

VERESEN

Financial Report 2015

www.vereseninc.com/financialreport2015

CORPORATE PROFILE

Veresen is a publicly-traded dividend paying corporation based in Calgary, Alberta that owns and operates energy infrastructure assets across North America.

Veresen is engaged in three principal businesses: a pipeline transportation business comprised of interests in the Alliance Pipeline, the Ruby Pipeline and the Alberta Ethane Gathering System; a midstream business which includes a partnership interest in Veresen Midstream Limited Partnership which owns assets in western Canada, an ownership interest in Aux Sable, a world-class natural gas liquids (NGL) extraction facility near Chicago, and other natural gas and NGL processing energy infrastructure; and a power business comprised of a portfolio of assets in Canada. Veresen is also developing Jordan Cove LNG, a six million tonne per annum natural gas liquefaction facility proposed to be constructed in Coos Bay, Oregon, and the associated Pacific Connector Gas Pipeline. In the normal course of business, Veresen regularly evaluates and pursues acquisition and development opportunities.

Veresen's Common Shares and Cumulative Redeemable Preferred Shares Series A, Series C and Series E trade on the Toronto Stock Exchange under the symbols "VSN", "VSN.PR.A", "VSN.PR.C" and "VSN.PR.E", respectively.

TABLE OF CONTENTS

1	2015 Highlights	24	Dividends
2	Management's Discussion and Analysis	26	Financial Instruments
2	Financial and Operating Highlights	28	Contractual Obligations and Commitments
3	Overall Financial Performance	28	Risks
3	Adjusted Net Income attributable to Common Shares	29	Business-Specific Risks
4	Net Income attributable to Common Shares	31	Market Pricing Risks
5	Distributable Cash	32	Common Business Risks
6	Cash from Operating Activities	36	Critical Accounting Policies
6	Accounting Standards and Basis of Presentation	36	Critical Accounting Estimates
6	Forward-Looking and Non-GAAP Information	37	New Accounting Standards
7	Business Overview	39	Non-GAAP Financial Measures
10	Description of Business	41	Selected Quarterly Financial Information
15	Results of Operations – By Business Segment	41	Related Party Transactions
15	Pipeline Business	41	Disclosure Controls And Procedures
17	Midstream Business	42	Internal Controls Over Financial Reporting
21	Power Business	43	Consolidated Financial Statements
21	Veresen – Corporate and Project Development	73	Corporate Information
22	Liquidity and Capital Resources		
23	Investing Activities		
23	Financing Activities		
24	Equity Financing Activities		
24	Debt Financing Activities		

2015 HIGHLIGHTS

Veresen is focused on building the best connected network of natural gas and natural gas liquids infrastructure in its geographic footprint, and we have built our business to be resilient through cyclical commodity price environments. Importantly, 75% of our fee-based earnings are generated from customers who are investment grade. On this solid base, we are executing on a large-scale, contracted growth program which will deliver sector-leading growth over the next five years.

In March 2016, the Cutbank Ridge Partnership (“CRP”) approved the \$930 million Saturn Phase 2 processing facility, the third major facility now under construction as part of the Veresen Midstream infrastructure development. Saturn Phase 2 is a fully contracted expansion to the recently constructed Saturn compressor station, and will add 200 million cubic feet per day (“MMcf/d”) of compression and 400 MMcf/d of processing, and significant inlet liquids and NGL handling facilities.

2015 FINANCIAL HIGHLIGHTS

- Distributable cash¹ of \$93 million or \$0.31 per Common Share for the fourth quarter and \$310 million or \$1.06 per Common Share for the year.
- Adjusted net income attributable to Common Shares² of \$15 million or \$0.05 per Common Share for the fourth quarter and \$66 million or \$0.23 per Common Share for the year.
- Net income attributable to Common Shares of \$14 million or \$0.05 per Common Share for the fourth quarter and \$60 million or \$0.21 per Common Share for the year.
- Cash from operating activities of \$76 million for the fourth quarter and \$287 million for the year.

(1) This is not a standard measure under GAAP and may not be comparable to similar measures used by other entities. See the reconciliation to the nearest GAAP measure provided in the MD&A.

(2) See the reconciliation of adjusted net income attributable to Common Shares to net income attributed to Common Shares in the tables provided in the MD&A.

KEY STRATEGIC INITIATIVES

- Veresen has successfully executed on its business plan over the past two years as demonstrated by the material growth in the Company’s fee-based cash flows. Today, the vast majority of Veresen’s distributable cash is generated from take-or-pay or fee-for-service contracts with no volume or direct commodity exposure, from a diverse portfolio of creditworthy counterparties.
- In 2015, Veresen completed a transformational transaction with the creation of Veresen Midstream Limited Partnership (“Veresen Midstream”), jointly owned and controlled by Veresen and affiliates of Kohlberg Kravis Roberts & Co. L.P. (“KKR”). Through this transaction, Veresen Midstream has become a leading independent natural gas gathering and processing business in the heart of the Montney.
- Alliance successfully recontracted its firm pipeline capacity and transitioned into its new market-focused services offering on December 1, 2015. Alliance has established a strong business model that is competitive in today’s market to ensure that the pipeline is in demand and generating stable cash flows for many years to come.
- Veresen advanced key activities related to Jordan Cove LNG and Pacific Connector Gas Pipeline (“Pacific Connector”). Veresen reached a significant regulatory milestone when the Federal Energy Regulatory Commission (“FERC”) issued a final Environmental Impact Statement (“EIS”) for the project in September 2015.

MANAGEMENT'S DISCUSSION AND ANALYSIS

For the year ended December 31, 2015

FINANCIAL AND OPERATING HIGHLIGHTS

(\$ Millions, except where noted)	Year ended December 31		
	2015	2014	2013
Operating Highlights (100%)			
Pipeline			
Alliance – billion cubic feet per day	1.488	1.556	1.565
Ruby – billion cubic feet per day	0.805	1.020	–
AEGS – thousand barrels per day ⁽¹⁾	285.6	289.1	293.0
Midstream			
Hythe/Steepprock – million cubic feet per day ⁽²⁾	392.6	399.9	412.9
Dawson – million cubic feet per day ⁽²⁾	634.1	–	–
Aux Sable – thousand barrels per day	66.5	70.2	70.4
Power – gigawatt hours (net)	603.0	638.0	561.5
Financial Results			
Equity income and dividend income	193	162	163
Operating revenues	187	302	292
Adjusted net income attributable to Common Shares ⁽³⁾⁽⁴⁾	66	25	41
Per Common Share (\$) – basic and diluted	0.23	0.11	0.21
Net income attributable to Common Shares	60	52	53
Per Common Share (\$) – basic and diluted	0.21	0.24	0.27
Cash from operating activities	287	215	217
Distributable cash ⁽³⁾⁽⁵⁾	310	253	229
Per Common Share (\$) – basic and diluted	1.06	1.12	1.15
Dividends paid/payable ⁽⁶⁾	291	227	200
Per Common Share (\$)	1.00	1.00	1.00
Capital expenditures ⁽⁷⁾	58	148	46
Financial Position			
Cash and short-term investments	58	51	25
Total assets	4,571	4,737	2,973
Senior debt	1,100	1,811	1,188
Subordinated convertible debentures	–	–	86
Shareholders' equity	3,087	2,532	1,306
Common Shares			
Outstanding – as at year end ⁽⁸⁾	298,979,989	285,029,036	201,476,244
Average daily volume	854,092	701,764	302,801
Price per Common Share – close (\$)	8.86	18.36	14.27

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

(2) Average daily volume for Hythe/Steepprock and Dawson is based on fee volumes and throughput volumes, respectively.

(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 adjusted net income attributable to Common Shares to net income attributable to Common Shares in the "Non-GAAP Financial Measures" section of this MD&A.

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

(6) Includes \$182 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 year ended December 31, 2015 (2014 – \$81 million).

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

(8) As at the close of markets on March 4, 2016 we had 303,096,627 Common Shares outstanding.

This MD&A, dated March 9, 2016, provides a review of the significant events and transactions that affected our performance during the year ended December 31, 2015 relative to December 31, 2014. It should be read in conjunction with our consolidated financial statements and notes as at and for the year ended December 31, 2015, prepared in accordance with accounting principles generally accepted in the United States ("US GAAP").

OVERALL FINANCIAL PERFORMANCE

Against the backdrop of a very challenging environment, Veresen delivered solid financial results in 2015. Our results highlight the sound underpinning of our business model – a diversified portfolio of well-located, high quality infrastructure assets supported by long-term fee-based contracts with a strong counterparty credit profile. Although Aux Sable, our one commodity-exposed business, continues to operate in a weak NGL market, the balance of our business is healthy, providing a stable foundation that will allow us to maintain performance through this cycle.

Adjusted Net Income attributable to Common Shares

(\$ Millions, except per Common Share amounts)	Three months ended December 31		Year ended December 31	
	2015	2014	2015	2014 ⁽²⁾
Adjusted net income before tax ⁽¹⁾				
Pipeline	67	44	256	137
Midstream	(1)	21	6	81
Power	8	1	11	6
Veresen – Corporate and Project Development	(44)	(43)	(157)	(161)
Tax expense	(8)	(10)	(26)	(22)
Adjusted net income	22	13	90	41
Preferred Share dividends	(7)	(4)	(24)	(16)
Adjusted net income attributable to Common Shares	15	9	66	25
Per Common Share (\$)	0.05	0.03	0.23	0.11

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

(2) Certain comparative figures for the year ended December 31, 2014 have been adjusted. Refer to the reconciliation noted above in the “Non-GAAP Financial Measures” section of this MD&A.

Adjusted net income attributable to Common Shares represents net income adjusted for specific items that are significant, but are not reflective of our underlying operations. We have presented adjusted net income attributable to Common Shares in order to enhance the comparability of our earnings. See the *Non-GAAP Financial Measures* section of this MD&A for the full definition of this term and the reconciliation to net income attributable to Common Shares.

For the year ended December 31, 2015, we generated adjusted net income attributable to Common Shares of \$66 million or \$0.23 per Common Share compared to an adjusted net income of \$25 million or \$0.11 per Common Share in 2014.

Our adjusted earnings reflect the benefits of diversification achieved through our strategic initiatives with a full year of earnings from our interest in the Ruby Pipeline and the successful re-contracting of the Alliance Pipeline under a new business model effective December 2015. The advancement of our Jordan Cove liquefied natural gas (“LNG”) development project continues to be a key component of our strategy. Funding requirements during the development phase are expensed.

Adjusted earnings from our Pipeline business increased year over year, resulting from our full-year ownership in the Ruby Pipeline, acquired November 6, 2014. We earned \$116 million from our interest in Ruby in 2015 compared to \$16 million in 2014. Alliance also contributed to higher adjusted earnings.

Power earnings were also higher this year with the incremental contributions from our new run-of-river hydro and wind facilities.

The increases in Pipeline and Power earnings were partially offset by lower Midstream adjusted earnings, driven by continuing weak NGL margins as a result of low propane prices, and reduced ownership in the Hythe/Steeprock business resulting from the sale of these facilities to Veresen Midstream in the first quarter of 2015.

Corporate costs in 2015 were relatively consistent with the prior year as higher Jordan Cove project spending was offset by lower general and administrative costs due to the revaluation of our long-term incentive plans.

Fourth quarter adjusted earnings reflect the same underlying factors as discussed above for the full year.

Net Income attributable to Common Shares

(\$ Millions, except per Common Share amounts)	Three months ended December 31		Year ended December 31	
	2015	2014	2015	2014
Net income before tax				
Pipeline	67	44	256	137
Midstream	(18)	21	(33)	81
Power	13	(3)	10	(2)
Veresen – Corporate and Project Development	(44)	(9)	(157)	(122)
Gain on sale of assets (impairment)	–	(5)	37	9
Tax expense	3	(13)	(19)	(25)
Net income from continuing operations	21	35	94	78
Net loss from discontinued operations	–	(10)	–	(10)
Net income, before extraordinary loss	21	25	94	68
Extraordinary loss, net of tax	–	–	(10)	–
Net income	21	25	84	68
Preferred Share dividends	(7)	(4)	(24)	(16)
Net income attributable to Common Shares	14	21	60	52
Per Common Share (\$)	0.05	0.08	0.21	0.24

For the year ended December 31, 2015, we generated net income attributable to Common Shares of \$60 million or \$0.21 per Common Share. In 2014, we generated net income of \$52 million or \$0.24 per Common Share.

In addition to factors impacting adjusted net income, as previously discussed, the following items are reflected in net income.

Midstream results include a non-cash provision of \$32 million related to Aux Sable and a \$37 million pre-tax gain relating to the sale of our Hythe/Steeprock assets to Veresen Midstream.

Power results include the impact of the revaluation of interest rate hedges resulting in an aggregate pre-tax \$1 million loss in 2015 compared to a pre-tax \$12 million loss last year.

Corporate results in 2014 included a \$39 million pre-tax gain associated with forward foreign exchange contracts we entered into to manage the foreign exchange exposure relating to the acquisition of our 50% convertible interest in Ruby that closed in the fourth quarter of 2014.

During 2014 we generated a pre-tax gain of \$14 million from the sale of certain power development projects and recorded a \$5 million impairment loss on land we hold in Ontario.

During the second quarter of 2015 we recognized an extraordinary after-tax loss of \$10 million representing the one-time net effect of Alliance's de-recognition of certain regulatory assets and liabilities.

Fourth quarter earnings were impacted by a provision of \$16 million related to Aux Sable and the revaluation of interest rate hedges within our Power segment resulting in an aggregate pre-tax \$5 million gain in 2015 compared to a \$4 million loss in 2014. During the fourth quarter of 2014, we recognized a \$34 million pre-tax gain associated with the foreign exchange contracts relating to our acquisition of Ruby, a \$12 million impairment of the three U.S. gas-fired assets sold, and a \$5 million land impairment.

Distributable Cash

(\$ Millions, except per Common Share amounts)	Three months ended December 31		Year ended December 31	
	2015	2014	2015	2014
Pipeline	83	57	302	180
Midstream	19	34	76	131
Power	14	8	43	47
Veresen – Corporate	(9)	(18)	(53)	(66)
Current tax	(7)	(9)	(34)	(23)
Preferred Share dividends	(7)	(4)	(24)	(16)
Distributable Cash⁽¹⁾	93	68	310	253
Per Common Share (\$)	0.31	0.26	1.06	1.12

(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 year ended December 31, 2015, we generated distributable cash of \$310 million or \$1.06 per Common Share, compared to \$253 million or \$1.12 per Common Share in 2014.

Increased cash flows generated by our Pipeline businesses and reduced Corporate costs were partially offset by reduced cash flows from our Aux Sable midstream business, and higher cash taxes and preferred share dividends.

Alliance generated an additional \$22 million of distributable cash compared to 2014, largely driven by the effects of a weaker Canadian dollar and the discontinuance of rate regulated accounting. A full year of earnings from Ruby, acquired in the fourth quarter of 2014, provided an additional \$100 million of distributable cash.

Distributions from Aux Sable decreased by \$46 million from 2014 due to the effect of weaker NGL market conditions and negative pipeline capacity margins. Overall, the Veresen Midstream transaction has been neutral to distributable cash, as the reduced contribution from Hythe/Steeprock, resulting from the change in ownership, has been offset by reduced Corporate administrative and interest costs.

Lower distributable cash from our power business in the year compared to 2014 resulted from the sale of our U.S. gas-fired cogeneration facilities in the first quarter of 2015, partially offset by incremental earnings from our Dasque-Middle run-of-river hydro and St. Columban and Grand Valley Phase III wind facilities, which commenced operations in 2015.

2015 Corporate costs were lower than last year, primarily due to lower general and administrative costs driven by the revaluation of our long-term incentive plans.

Current tax in the year was higher due to higher U.S. pipeline earnings and the impact of a weaker Canadian dollar on U.S.-based taxes. Our April 1, 2015 issuance of Series E Preferred Shares resulted in higher Preferred Share dividends in 2015.

Distributable cash increased in the fourth quarter of 2015 due to the same factors discussed above with the exception of the sale of our U.S. gas-fired cogeneration facilities in the first quarter of 2015. These facilities did not have a material impact on fourth quarter 2014 cash flows.

Distributable cash on a per share basis in 2015 was impacted by common shares issued in April and October 2014 to fund our growth initiatives.

Cash from Operating Activities

(\$ Millions)	Three months ended December 31		Year ended December 31	
	2015	2014	2015	2014
Pipeline	80	58	302	182
Midstream	19	47	94	138
Power	24	(2)	74	38
Power – operating working capital from discontinued operations	–	7	–	12
Veresen – Corporate and Project Development	(47)	(39)	(183)	(155)
	76	71	287	215

For the year ended December 31, 2015, we generated \$287 million of cash from operating activities compared to \$215 million in 2014. Higher operating cash flows during the fourth quarter from our Pipeline business, partially offset by a decrease in our Midstream business, generally reflect the same factors impacting distributable cash, as well as changes in non-cash working capital.

ACCOUNTING STANDARDS AND BASIS OF PRESENTATION

Our consolidated financial statements as at and for the year ended December 31, 2015 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 2015 consolidated financial statements. Additional information concerning our business is available on SEDAR at www.sedar.com or on our website at 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 impact of Alliance's new services framework on Alliance's future earnings;
- Aux Sable's ability to realize upon the extraction agreements with producers;
- the 2016 pricing environment for ethane and propane;
- the timing of the completion of construction and in-service date of the Sunrise and Tower gas plants, the Saturn compression station expansion and the Hythe liquids recovery project;
- the projected date for a final investment decision on Jordan Cove LNG and Pacific Connector Gas Pipeline;
- the effective elimination of cash taxes for approximately the next five years, excluding Part VI.1 taxes on Preferred Share dividends, as a result of our U.S.-based organizational restructuring
- the projected date for commencing LNG production from Jordan Cove LNG;
- 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.

BUSINESS OVERVIEW

We are a Canadian corporation committed to actively managing and growing our pipeline transportation, midstream services, power generation, and liquefied natural gas businesses. We focus on high-quality, long-life infrastructure assets in North America with diversity in asset type and geography, and which contribute toward stable cash flow generation. Our businesses are underpinned by a prudent capital structure and investment-grade credit ratings.

Strategy

Our strategy is to continue building the best contracted network of natural gas and NGL infrastructure in our geographic footprint. We are focused on owning the right infrastructure in the right places to support long-term trends in gas and NGL flows and to add value to our customers. In executing this strategy, we adhere to the following key principles:

- Own, build, operate and provide services with natural gas and NGL processing, transportation, and storage infrastructure that best connect competitive supply with high-value markets;
- Focus on primarily fee-based commercial structures that are responsive to customers and generate predictable, long-term earnings and cash flows;
- Pursue focused growth within our existing footprint, which gives us a strong competitive advantage;
- Consistently deliver safe and reliable operations, cost control, and effective project development and construction management; and
- Maintain a strong balance sheet and ample liquidity to adapt to market conditions and opportunities, with a prudent capital structure that supports investment grade credit ratings.

Over the last five years, our strategy has materially grown our fee-based cash flows to reduce exposure to Aux Sable, our only business with direct commodity price exposure. A large majority of our distributable cash is now generated from take-or-pay contracts with no volume or commodity price risk.

Our take-or-pay and fee-based cash flows are supported by diverse businesses and long-term contracts. We've improved the diversity and contribution of the fee-based business by:

- Acquiring our preferred interest in the Ruby pipeline in late-2014;
- Creating Veresen Midstream which will drive growth in fee-based cash flow in 2018 and beyond; and
- Growing our Power portfolio, with new renewable resource-based facilities commencing operations in 2015.

Advancement of Strategy in 2015

In 2015, we made significant progress in the advancement of our strategy, as detailed below.

Alliance

December 1, 2015 marked a significant, new chapter in Alliance's history as it began operating under its new, market-focused service model.

On June 30, 2015 and July 9, 2015, the National Energy Board of Canada ("NEB") and the U.S. Federal Energy Regulatory Commission ("FERC") each approved, as filed by Alliance, the new services and associated terms and conditions, as well as the firm tolls effective December 1, 2015 for the new Canadian and U.S. service offerings, respectively. In addition, regulatory approval was received to change the Hydrocarbon Dewpoint ("HCDP") gas quality specification from -10 degrees Celsius to -5 degrees Celsius, effective December 1, 2015. The new HCDP specification changes in both Canada and the U.S. will enhance shipper access to rich gas transportation and facilitate an increase in the NGL content of the gas Alliance transports.

The approvals allowed Alliance to move forward with its new market-focused services and the conversion of its executed precedent agreements into firm transportation contracts.

Alliance successfully re-contracted its receipt capacity through 2018, and approximately 90% of firm receipt capacity in 2019 and 2020, with average contract lengths of 5.3 years. With demand far in excess of available capacity, Alliance successfully contracted all of its available winter 2015/2016 and summer 2016 seasonal firm capacity, as well as additional short-term firm service contracts with terms up to 90 days to capture this strong demand for transportation service. In December 2015, Alliance's average daily throughput to the Aux Sable inlet was 1.65 bcf/d. This includes the marketing of available interruptible transportation services, resulting in an average of 73 mmcf/d of interruptible receipt service and 77 mmcf/d of interruptible delivery service during the month. Alliance will continue to use its flexible and competitive suite of new services, along with the operational capabilities and reliability of its system, to optimize the physical and economic utilization of its pipeline.

The liquids-rich natural gas transported on the Alliance pipeline under the new contracts increase the need for NGL fractionation capacity at Aux Sable's Channahon facility. As a result, the owners of Aux Sable, including us, approved the construction of a 24,500 barrels per day expansion of the fractionation facility, which is expected to be in service in mid-2016.

Alliance's new services offerings are further discussed in the *Description of Business – Pipeline Business – Alliance Pipeline* section of this MD&A.

Veresen Midstream LP

On December 22, 2014, a new entity, Veresen Midstream Limited Partnership ("Veresen Midstream"), was formed, which is jointly owned and controlled by us and affiliates of Kohlberg Kravis Roberts & Co. L.P. ("KKR"), a global investment firm. On March 31, 2015, we funded our interest in Veresen Midstream by contributing our Hythe/Steeprook gathering and processing assets. Veresen Midstream also closed the acquisition of natural gas gathering and compression assets in the Dawson area of northeastern British Columbia from Encana Corporation ("Encana") and the Cutbank Ridge Partnership ("CRP") on March 31, 2015. As part of this transaction, Veresen Midstream agreed to undertake up to \$5 billion of new midstream expansion for Encana and CRP in the Montney region over a five year period. CRP is a partnership between Encana and Cutbank Dawson Gas Resources Ltd., a subsidiary of Mitsubishi Corporation.

All infrastructure acquired and to be developed associated with this transaction, collectively the "Dawson Assets", is supported by 30-year fee-for-service arrangements with Encana and CRP. Veresen Midstream is our primary growth vehicle for our Canadian natural gas and NGL midstream business.

Veresen Midstream established us as a leading player in the core of the Montney, one of North America's most prolific and competitive resource plays. The partnership required no up-front funding from us as it was funded initially through non-recourse debt and a cash contribution from KKR, while we funded our initial investment by contributing our Hythe/Steeprock assets. The definitive agreements provide Veresen Midstream with a large multi-year capital program to construct contracted midstream infrastructure under favourable economic terms, and a powerful platform to pursue additional third-party growth opportunities.

On October 6, 2015, CRP sanctioned the 400 mmcf/d Sunrise gas plant. The estimated capital cost for the project (plant and ancillary facilities) is \$860 million (gross). Construction of the Sunrise gas plant is now underway. On December 7, 2015, CRP sanctioned the \$715 million (gross) 200 mmcf/d Tower rich gas processing complex, which is the second major new gas plant now under construction. Both Sunrise and Tower are expected to be in service in late 2017.

On March 9, 2016, we announced the sanctioning of the 200 mmcf/d Saturn compression station expansion ("Saturn Phase II"). The estimated cost of the fully contracted expansion project is \$930 million (gross) with an anticipated in-service date in mid-2018. Veresen Midstream is also advancing other projects, including enhanced liquids recovery at the Hythe gas processing facility which was recently sanctioned. The enhanced liquids recovery project is expected to be in-service during the third quarter of 2016 with an estimated capital cost of \$25 million (gross).

The Veresen Midstream transaction and expansion projects are further discussed in the *Description of Business – Midstream Business – Veresen Midstream* section of this MD&A.

Burstall Ethane Storage Facility

We will build and operate a new wholly-owned ethane storage facility located near Burstall, Saskatchewan, approximately 20 kilometres north of the Empress NGL complex. The salt cavern facility will have capacity to store approximately 1 million barrels of ethane, and will be connected via pipeline to our Alberta Ethane Gathering System. The expected capital cost of the storage facility and related infrastructure is approximately \$140 million. The Burstall facility will provide our customers with valuable operational storage as ethane imports to Empress from the North Dakota Bakken grow.

We have entered into an agreement with NOVA Chemicals Corporation ("NOVA") where NOVA will use the majority of the storage capacity under a 20-year arrangement. Subject to final regulatory approvals, the facility is expected to be in service in the second half of 2018. Once operational, we expect the storage facility to provide stable cash flows, comprised largely of fixed payments which are not dependent on utilization levels.

Jordan Cove LNG Development Project

During 2015, we continued to make steady progress in advancing the development of our Jordan Cove LNG and Pacific Connector Gas Pipeline ("Pacific Connector") projects. On September 30, 2015, the FERC issued a final Environmental Impact Statement ("EIS") for Jordan Cove LNG and Pacific Connector, marking a significant regulatory milestone. We expect the FERC to issue a final order and certificate for Jordan Cove LNG and Pacific Connector in due course. We are comfortable with the mitigation conditions recommended in the conclusions of the final EIS.

Financing Strategy

During 2015 we undertook a number of steps to strengthen our liquidity, reduce borrowing costs and reduce leverage. On March 31, 2015 we used the \$420 million in cash we received from Veresen Midstream to partially repay our Acquisition Credit Facility related to the Ruby acquisition in the fourth quarter of 2014. On April 1, 2015 we issued 8.0 million Cumulative Redeemable Preferred Shares, Series E ("Series E Preferred Shares") at a price of \$25.00 per share for total gross proceeds of \$200 million. Proceeds from our issuance of the Series E Preferred Shares were further used to repay a portion of the Acquisition Credit Facility.

On July 31, 2015, our Revolving Credit Facility was increased from \$550 million to \$750 million and the term extended such that it now matures on May 31, 2019. In August 2015, we drew from our Revolving Credit Facility to repay the remaining outstanding balance of the Acquisition Credit Facility.

As a result of the above activities, we reduced our debt to total capitalization ratio from 42% to 26% over the course of the year.

DESCRIPTION OF BUSINESS

Pipeline Business

Our Pipeline business represented 58% of our total asset base as at December 31, 2015 and is comprised of:

- Alliance Pipeline (50% ownership);
- Ruby Pipeline (50% convertible preferred ownership) and
- Alberta Ethane Gathering System (“AEGS”) (wholly-owned).

Ruby and AEGS are stable cash flow generators that are supported by take-or-pay transportation agreements. Alliance has re-contracted all of its year-round firm receipt capacity through 2018, and approximately 90% of firm capacity in 2019 and 2020, with average contract durations of 5.3 years.

Alliance Pipeline

Alliance owns and manages an integrated, high-pressure natural gas and natural gas liquids pipeline that extends approximately 3,000 kilometres across North America. The system is capable of transporting 1.65 billion cubic feet per day of liquids-rich natural gas. 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. At its terminus, the Alliance pipeline connects with five interstate natural gas pipelines and two local natural gas distribution systems with an aggregate of over 6 billion cubic feet per day of production physically connected into the Pipeline. These connected pipelines and local distribution systems serve major natural gas consuming areas in the midwestern United States and Ontario. The Alliance pipeline also connects at its terminus with Aux Sable's extraction facility, in which we hold a 42.7% ownership interest.

Alliance's new services offering, effective December 1, 2015, includes full-path service from Canadian receipt points to the delivery point at the Canada-USA border, and on to the delivery points near Chicago via the US leg of the pipeline. Segmented services are also offered, including the option of nominating volumes from a Canadian receipt point, in one of two zones, to the new Canadian Alliance Trading Pool (“ATP”). These services offer shippers competitive fixed tolls for terms out to ten years, and biddable tolls for interruptible and seasonal firm service. The design of the new services offering also includes rich gas services and the ability to stage contract commitments.

Alliance's new services include the following key service elements:

- ATP – a new Canadian trading pool allowing receipt and delivery shippers to trade gas. The ATP is a notional point connecting the receipt zones to the delivery zone (which extends from the ATP to the Canada-USA border), where the Canadian portion of the pipeline connects with the US leg of the pipeline. The introduction of the ATP facilitates the segmentation of services on the pipeline into receipt and delivery services, providing a platform for receipt and delivery shippers to transfer title and allowing shippers to access Term Park and Loan services.
- Firm Receipt Service includes two zones with fixed volumetric tolls, allowing shippers to move gas from their contract receipt point(s) to the ATP. Firm receipt shippers will also have access to a Priority Interruptible Transportation Service (PITS) that can provide additional transportation access as production volumes grow. PITS is available to Firm Receipt Service shippers with terms of three years or more and allows them to flow up to 25% more volume at their contracted receipt points.
- Firm Delivery Service allows shippers to deliver gas from the ATP to the Canada-USA border. Fixed tolls are offered on one to ten year contract terms.
- Firm Full Path Service is volumetrically tolled service from Canadian receipt points to Chicago with fixed tolls.

Pipeline Abandonment Costs

The NEB Land Matters Consultation Initiative is an initiative that requires NEB regulated pipelines to set aside funds to cover future abandonment costs. The NEB provided several key guiding principles under this initiative, including the position that abandonment costs are legitimate costs of providing transportation services and are recoverable, upon NEB approval, from shippers.

Alliance collects abandonment funds through a pipeline abandonment demand surcharge. These funds are set aside in a trust until such time that the funds are required to settle abandonment-related expenditures.

Ruby Pipeline

Ruby is a 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 us), 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, operates Ruby on a day-to-day basis.

Long-term take-or-pay contracts are in place with a strong mix of investment grade shippers for approximately 1.1 bcf/d with a weighted average remaining contract term of approximately seven years.

AEGS

AEGS is an integrated pipeline system that transports purity ethane from various Alberta ethane extraction plants to major petrochemical complexes located near Joffre and Fort Saskatchewan, Alberta. The system also transports ethane to and from third party underground storage in Fort Saskatchewan. Expansion projects commissioned in 2012 near Fort Saskatchewan increased the overall length of AEGS to 1,330 km. These projects included additional pipeline and metering to directly connect AEGS to the major petrochemical complex in Fort Saskatchewan, and the installation of a new pipeline leg for the receipt of ethane from Aux Sable's Heartland Off-gas facility.

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

Midstream Business

As at December 31, 2015, our Midstream business represented 17% of total assets.

Veresen Midstream

On March 31, 2015, we funded our interest in Veresen Midstream by contributing our Hythe/Steeprock gathering and processing assets valued at \$920 million, and in exchange received from Veresen Midstream \$420 million in cash, resulting in a 50% equity position valued at \$500 million. KKR funded its 50% interest in Veresen Midstream by contributing \$500 million in cash.

Veresen Midstream closed the acquisition of natural gas gathering and compression assets in the Dawson area of northeastern British Columbia from Encana and CRP on March 31, 2015. The aggregate purchase price of the acquisition was approximately \$760 million, comprised of approximately \$435 million for operating compression facilities and pipelines, \$155 million for work in progress associated with the Saturn compressor station, and \$170 million for other work in progress, including the Sunrise and Tower gas plants and additional gas gathering pipelines. All infrastructure acquired and to be developed associated with this transaction is supported by 30-year fee-for-service arrangements with Encana and CRP.

On March 31, 2015, Veresen Midstream closed a US\$575 million drawn Term Loan B and established \$1,350 million in credit facilities. Proceeds from these facilities, which are non-recourse to us, were used to fund the initial acquisition of assets from Encana and CRP, as well as ongoing construction.

Veresen Midstream will fund approximately 55% to 60% of the construction costs of the Sunrise, Tower and Saturn gas plants with its existing \$1.275 billion credit facility and additional non-recourse debt at the partnership level, with the balance to be contributed over time by us and KKR. We are funding and intend to fund the majority of our share of future contributions to Veresen Midstream with ongoing proceeds received from equity issued in connection with our Premium Dividend™ and Dividend Reinvestment Plan.

Veresen Midstream is currently comprised of:

- Hythe Processing Facility, with 176 mmcf/d of sour gas processing capacity and 340 mmcf/d of sweet gas processing capacity. It is connected to the Alliance and TransCanada gas pipeline systems. The Hythe facility includes a sulphur plant with a capacity of approximately 120 tonnes/d;
- Steeprock Processing Facility, with capacity of 198 mmcf/d, is connected to the Hythe gas plant and the Alliance and TransCanada natural gas pipeline systems;
- Gathering and Compression System, consisting of 900 km of gas gathering lines and 100,000 horsepower of compression operated by Encana on behalf of Veresen Midstream;
- Saturn Compression Station (“Saturn Phase I”), with 200 mmcf/d of compression capacity, which commenced operations in June 2015 ahead of schedule and under budget at a cost of \$155 million;
- Tower Gas Plant, a 200 mmcf/d facility under construction with an anticipated in-service date in late 2017 and an expected cost of \$715 million;
- Sunrise Gas Plant, a 400 mmcf/d facility under construction with an anticipated in-service date in late 2017 and an estimated cost of \$860 million; and
- Saturn Phase II, representing an additional 200 mmcf/d of compression and 400 mmcf/d of refrigeration, with an anticipated in-service date in mid-2018 and an expected cost of \$930 million.

Hythe/Steeprock earnings are primarily generated from a long-term take-or-pay midstream services agreement, referred to as the “Hythe/Steeprock MSA”, entered into on February 9, 2012 with Encana. The Hythe/Steeprock 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.

Dawson earnings, representing the Gathering and Compression System, Saturn Phase I and gas plants currently under construction, are and will be primarily generated from fee-for-service agreements. Under these agreements, unit capital fees are set for individual components in order to achieve a target rate of return based on invested capital and expected throughput. Facility fees will be fixed 12 months after commercial operations, and gathering fees will be reset at defined periods based on actual throughput. These and other contract mechanisms are in place to provide strong expected returns on capital, with downside financial protection. One such downside protection is a potential payout of minimum costs associated with certain gathering and compression assets. The potential payout of minimum costs will be assessed in the eighth year of the assets’ service period and is based on whether there is an overall shortfall of total system cash flows from natural gas gathered and compressed under certain service agreements. The potential payout amount can be reduced in the event Veresen Midstream markets unutilized capacity to third party users.

All of our and half of KKR’s Veresen Midstream equity is held in partnership units that are eligible to receive cash distributions. The remaining half of KKR’s initial equity investment is in the form of payment-in-kind (“PIK”) units which do not receive cash distributions and instead accrete at a rate equal to the cash yield on the remaining equity plus 4% per year. The PIK units are convertible to cash-paying units after four years from the initial issuance at either KKR’s or our option.

This structure provides us with a disproportionately higher share of cash flow during the construction period, prior to the Sunrise and Tower gas plants being placed in-service. The transaction has been neutral to our distributable cash in 2015 and is expected to be accretive as new capital projects are placed in-service. We and KKR will have equal governance rights in Veresen Midstream so long as either partner’s equity interest remains above 35%.

Aux Sable

Aux Sable is comprised of:

- Aux Sable Liquid Products (42.7% ownership), which owns the Channahon Facility, a world-scale NGL extraction and fractionation facility near the terminus of the Alliance pipeline, capable of recovering up to 107,000 barrels per day of ethane, propane, normal butane, iso-butane and natural gasoline;
- Aux Sable Midstream (42.7% ownership), which owns the following assets:
 - the Palermo Conditioning Plant in the Bakken region of North Dakota, with a processing capacity to 80 mmcf/d, which removes the heavier hydrocarbon compounds from the rich gas delivered into the Prairie Rose Pipeline, while leaving the majority of the natural gas liquids;
 - the Prairie Rose Pipeline, a 12-inch diameter, 133-km (83-mile) pipeline with an estimated capacity of 110 mmcf/d, which gathers liquids-rich gas from the Palermo Plant and other sources for delivery into the Alliance pipeline system; and
 - storage facilities, downstream NGL pipelines and loading facilities adjacent to the Channahon facility;
- Aux Sable Canada (50% ownership), which owns:
 - NGL injection facilities on the Alliance pipeline in Alberta and B.C.;
 - a minority interest in the Septimus and Wilder Gas Plants, two natural gas processing plants with a processing capacity of 75 mmcf/d and 60 mmcf/d, respectively, located in the liquids-rich Montney region of British Columbia;
 - the Septimus Pipeline, a 20-km pipeline capable of delivering 400 mmcf/d of natural gas from the Septimus Gas Plant to the Alliance pipeline; and
 - the Heartland Off-gas Facility, an off-gas processing facility located in Fort Saskatchewan, Alberta; and
- Alliance Canada Marketing (42.7% ownership), which holds long-term firm natural gas transportation capacity on the Alliance pipeline used for balancing makeup gas for Aux Sable's Channahon Facility.

Pursuant to a long-term NGL Sales Agreement with BP Products North America Inc., Aux Sable sells all production from its Channahon Facility 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. The percentage share of net margins varies and depends upon specified thresholds being reached. In addition, BP compensates Aux Sable for all associated operating and maintenance costs, and subject to certain limits, costs incurred to source feedstock gas supply and capital costs associated with its Channahon Facility.

Aux Sable Midstream's Palermo Conditioning Plant and Prairie Rose Pipeline in the Bakken earns processing and pipeline transportation fees, respectively, and retains a margin on the NGLs recovered.

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 were focused on working with producers who were developing liquids-rich fields in the Montney and Duvernay which were not yet connected to the Alliance Pipeline system. Aux Sable offered Rich Gas Premium agreements which include sharing 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 Canada may have gas positions in multiple locations on the Alliance pipeline as a result of the RGP agreements. In conjunction with its RGP agreement contracting, Aux Sable has developed gas marketing, transportation and commercial arrangements to support and manage the supply of liquids-rich natural gas to the Channahon Facility. This business may involve Aux Sable purchasing and selling natural gas and/or holding transportation on Alliance pipeline or adjacent transportation systems, in order to mitigate potential exposure to commodity prices or basis differentials.

Aux Sable has executed several Rich Gas Premium agreements and, as a result, Aux Sable's ability to extract additional NGLs at the Channahon Facility has reached the plant's current capacity. In response to customer demand, the owners of Aux Sable, including us, 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). In November 2015, Aux Sable entered into an agreement with a third party for the sale of substantially all of the expanded propane capacity.

Power Business

We have grown our Power business through greenfield development and acquisitions into a diverse portfolio of power generation facilities capable of generating 888 MW (gross). A significant portion of our power facilities is underpinned with long-term capacity payment-based energy contracts that provide stable cash flows not significantly influenced by commodity prices or volumes of electricity generated. Our power assets represented 23% of our total asset base as determined at December 31, 2015 and are comprised of (wholly-owned except where stated otherwise):

- Gas-fired generation and district energy
 - York Energy Centre generation facility in Ontario (400 MW; 50% ownership);
 - East Windsor cogeneration facility in Ontario (86 MW);
 - London cogeneration and district energy facility in Ontario (17 MW);
 - P.E.I. Energy Systems, a district energy facility in Charlottetown, P.E.I.;
- Waste heat
 - two EnPower facilities in B.C. (10 MW);
 - four NRGreen facilities in Saskatchewan (20 MW; 50% ownership) and one in Alberta (13 MW; 50% ownership);
- Run-of-river hydro
 - Glen Park in New York (33 MW);
 - Furry Creek in B.C. (11 MW; 99% ownership);
 - Upper and Lower Clowhom in B.C. (22 MW);
 - Dasque-Middle in B.C. (20 MW);
- Wind power
 - Grand Valley phases I, II and III in Ontario (9 MW, 11 MW and 40 MW, respectively; 75% ownership); and
 - St. Columban in Ontario (33 MW; 90% ownership).

Gas-fired and District Energy Facilities

Each of our gas-fired generation facilities in Ontario sells capacity and electricity pursuant to long-term power purchase agreements with investment-grade counterparties. The power purchase agreements are structured to pay the facilities contracted rates for having capacity available and for the recovery of fuel costs. As a result, earnings and cash flows from the facilities are realized primarily by capacity payments and are not significantly impacted by the volume of electricity produced or by commodity price fluctuations. In addition to capacity payments, the majority of these facilities have the opportunity to earn energy margins.

Our district energy systems in Ontario and Prince Edward Island consist of central production plants which 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.

On January 8, 2015, we closed the sale of our gas-fired generation facilities located in Colorado and California for a sale price of US\$27 million.

Renewables

Waste Heat Facilities

Our waste heat facilities in Saskatchewan, Alberta and British Columbia use Energy Recovery Generation (ERG[®]) technology and waste heat generated by certain Alliance and Spectra pipeline compressor stations. Electricity generated in Saskatchewan and British Columbia is sold to Saskatchewan Power Corporation and to BC Hydro, respectively, under long-term power purchase agreements. NRGreen, in which we hold a 50 percent ownership interest, completed the 13-MW Whitecourt, Alberta waste heat power generation facility, and commenced operations on December 8, 2014. Electricity generated from the Whitecourt facility is sold into the Alberta Power Pool on a spot basis.

Run-of-River Facilities

We own four run-of-river hydroelectric facilities in British Columbia with an aggregate 53 MW of generation capacity. These facilities sell power to BC Hydro under long-term electricity purchase agreements. We are paid for the volume of electricity actually delivered based on fixed, inflation-escalated prices. The Dasque-Middle run-of-river hydro facility was placed into commercial service on May 21, 2015.

Our portfolio of run-of-river facilities also includes the 33-MW Glen Park facility, located in upstate New York. Glen Park sells all of its output at prevailing market terms on a month-to-month basis.

Wind Power Facilities

We hold a 75% ownership interest in the Ontario-based Grand Valley wind facilities, which sell power to the Ontario Power Authority (OPA) under long-term contracts. Phase III commenced operations on December 4, 2015.

The St. Columban wind project commenced operations on July 16, 2015.

RESULTS OF OPERATIONS – BY BUSINESS SEGMENT

Pipeline Business

(\$ Millions, except where noted)	Three months ended December 31, 2015				Three months ended December 31, 2014			
	Total	Alliance	Ruby ⁽³⁾	AEGS	Total	Alliance	Ruby ⁽³⁾	AEGS
Equity income	34	34	–	–	26	26	–	–
Dividend income	31	–	31	–	16	–	16	–
Earnings before interest, tax depreciation and amortization (“EBITDA”)⁽¹⁾	6	–	–	6	7	–	–	7
Depreciation and amortization	(3)	–	–	(3)	(4)	–	–	(4)
Interest and other finance	(1)	–	–	(1)	(1)	–	–	(1)
Net income before tax	67	34	31	2	44	26	16	2
Distributable cash	83	47	31	5	57	36	16	5
Volumes (100%)		1.481	1.013	279.6		1.547	0.845	296.8
		bcf/d	bcf/d	mbbls/d⁽²⁾		bcf/d	bcf/d	mbbls/d ⁽²⁾

(\$ Millions, except where noted)	Year ended December 31, 2015				Year ended December 31, 2014			
	Total	Alliance	Ruby ⁽³⁾	AEGS	Total	Alliance	Ruby ⁽³⁾	AEGS
Equity income	131	131	–	–	112	112	–	–
Dividend income	116	–	116	–	16	–	16	–
Earnings before interest, tax depreciation and amortization (“EBITDA”)⁽¹⁾	28	–	–	28	28	–	–	28
Depreciation and amortization	(14)	–	–	(14)	(14)	–	–	(14)
Interest and other finance	(5)	–	–	(5)	(5)	–	–	(5)
Net income before tax	256	131	116	9	137	112	16	9
Distributable cash	302	167	116	19	180	145	16	19
Volumes (100%)		1.488	0.805	285.6		1.556	1.020	289.1
		bcf/d	bcf/d	mbbls/d⁽²⁾		bcf/d	bcf/d	mbbls/d ⁽²⁾

(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.

(3) We acquired the 50% convertible preferred interest in Ruby Pipeline on November 6, 2014.

Alliance Pipeline

Operational Highlights

Transportation deliveries for the year ended December 31, 2015 averaged 1.488 bcf/d, compared to 1.556 bcf/d in 2014. After the implementation of the new services model on December 1, 2015, transportation deliveries averaged 1.65 bcf/d for the month of December, reflecting strong demand for interruptible service. Alliance also contracted 73 mmcf/d of interruptible receipt service and 77 mmcf/d of interruptible delivery service through a bidding process in December. Toll rates for interruptible service ranged from 108% to 129% of firm rates.

On August 7, 2015, the Alliance Pipeline system was shut down for approximately one week following the detection of hydrogen sulphide (“H2S”) that entered the system as a result of complications experienced by an upstream operator. During that time, Alliance reduced the amount of H2S in the pipeline to a safe level through flaring within the confines of Alliance’s Alameda compressor station in Saskatchewan. Alliance followed regulatory procedures and took additional precautionary measures to protect people, the site and the surrounding area. Monitoring stations were installed to ensure that air quality standards were being met. The incident did not damage or impact the integrity of the pipeline system.

Financial Highlights

Distributable cash for the year ended December 31, 2015 was \$167 million compared to \$145 million in 2014. The increase was largely driven by a weaker Canadian dollar, higher negotiated depreciation rates applicable to the first 11 months of 2015 and the discontinuance of rate regulated accounting.

Net income before tax for the year ended December 31, 2015 was \$131 million compared to \$112 million for 2014. The increases primarily reflect the same factors impacting distributable cash, partially offset by the impact of the H2S shutdown. The financial impact of the shutdown was not material to us. Alliance is pursuing avenues for the recovery of the costs associated with this incident.

Fourth quarter results reflect the same factors discussed above excluding the H2S shutdown which impacted third quarter earnings. December results were impacted by lower toll rates under the new services model, partially offset by lower operating costs.

Ruby Pipeline

Operational Highlights

Long-term ship-or-pay contracts are in place for approximately 1.1 bcf/d, or 71%, of the pipeline’s capacity, 90% of which are held by investment grade shippers. The average remaining length of the contracts is over seven years. Transportation deliveries for the year ended December 31, 2015 averaged 0.805 bcf/d compared to 1.020 bcf/d in 2014. Volumes are lower than the contracted levels as a result of downstream pipeline maintenance, mild weather and less demand for volumes into storage.

Financial Highlights

Distributable cash and net income for the year ended December 31, 2015 was \$116 million representing annual distributions we are entitled to as holders of the convertible preferred interest. Distributable cash and net income for the year ended December 31, 2014, was \$16 million, representing our portion of the annual distributions from the date of acquisition.

AEGS

Operational Highlights

Toll volumes for the year ended December 31, 2015 were 285.6 mbbls/d, consistent with volumes of 289.1 mbbls/d for 2014.

Financial Highlights

For the year ended December 31, 2015, AEGS generated \$19 million in distributable cash and \$9 million in net income before tax, consistent with last year’s results.

Midstream Business

(\$ Millions, except where noted)	Three months ended December 31, 2015				Three months ended December 31, 2014		
	Total	Hythe/ Steepprock	Veresen ⁽¹⁾ Midstream	Aux Sable	Total	Hythe/ Steepprock	Aux Sable
Equity income (loss)	(18)	–	2	(20)	13	–	13
EBITDA	–	–	–	–	18	18	–
Depreciation and amortization	–	–	–	–	(10)	(10)	–
Net income (loss) before tax	(18)	–	2	(20)	21	8	13
Distributable cash	19	–	15	4	34	17	17
Volumes (100%)							
Hythe/Steepprock ⁽²⁾		–	391.9			400.8	
Dawson ⁽³⁾		–	709.0			–	
Ethane				26.5			21.0
Propane plus				46.1			46.7
		–	1,100.9	72.6		400.8	67.7
		mmcf/d	mmcf/d	mbbls/d		mmcf/d	mbbls/d

(\$ Millions, except where noted)	Three months ended December 31, 2015				Three months ended December 31, 2014		
	Total	Hythe/ Steepprock	Veresen ⁽¹⁾ Midstream	Aux Sable	Total	Hythe/ Steepprock	Aux Sable
Equity income (loss)	(44)	–	(1)	(43)	48	–	48
EBITDA	21	21	–	–	73	73	–
Depreciation and amortization	(10)	(10)	–	–	(40)	(40)	–
Net income (loss) before tax	(33)	11	(1)	(43)	81	33	48
Distributable cash	76	20	45	11	131	74	57
Volumes (100%)							
Hythe/Steepprock ⁽²⁾⁽⁴⁾		393.8	392.6			399.9	
Dawson ⁽³⁾⁽⁴⁾		–	634.1			–	
Ethane				21.4			22.6
Propane plus				45.1			47.6
		393.8	1,026.7	66.5		399.9	70.2
		mmcf/d	mmcf/d	mbbls/d		mmcf/d	mbbls/d

(1) Veresen Midstream results are for the applicable periods from April 1 to December 31, 2015.

(2) Hythe/Steepprock 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.

(3) Dawson throughput volumes represent actual volumes processed from our primary customer.

(4) Veresen Midstream volumes include volumes from Hythe/Steepprock and Dawson from April 1 to December 31, 2015.

Hythe/Steepprock

In the first quarter of 2015, the Hythe/Steepprock assets, while wholly owned by us, generated \$20 million of distributable cash and \$11 million of net income prior to the Veresen Midstream transaction closing on March 31, 2015. Results for the last nine months of the year for the Hythe/Steepprock assets form part of Veresen Midstream's results, discussed below.

Veresen Midstream

Operating and financial results of the Hythe/Steepprock assets within Veresen Midstream exclude first quarter results when they were wholly owned by us.

The net book value of the Hythe/Steepprock assets contributed by us to fund our interest in Veresen Midstream on March 31, 2015 was \$839 million, resulting in a pre-tax gain on sale to \$37 million attributable to the monetary portion of the transaction.

Operational Highlights

During the fourth quarter of 2015, actual volumes received from Encana and CRP at Dawson averaged 709.02 mmcf/d, compared to 584.7 mmcf/d and 607.8 mmcf/d during the second and third quarters respectively. The increased throughput is a result of the resolution of bottleneck issues in the northern part of Dawson. Reduced throughput volumes in the southern portion of Dawson resulting from integrity maintenance-related curtailments imposed by downstream pipelines were resolved by the end of the fourth quarter.

Fee volumes at Hythe/Steepprock averaged 391.9 mmcf/d and 392.9 mmcf/d for the three and twelve months ending December 31, 2015. Fee volumes are comprised of the minimum volume commitment under the Hythe/Steepprock MSA and natural gas from third party producers. Compared to the same periods last year, the Hythe/Steepprock fee volumes decreased two percent in line with the contractual commitment. During the three and twelve months ending December 31, 2015, the Hythe and Steepprock facilities operated at reliability factors of 99.8% and 99.9%, respectively, exceeding their respective target factors under the MSA.

To fund the initial acquisition of assets from Encana and CRP, as well as ongoing construction, Veresen Midstream had fully drawn its US\$575 Term Loan B and \$370 million from its \$1,275 million expansion credit facility as at December 31, 2015. By the end of the year, Veresen Midstream had invested \$312 million in the Sunrise and Tower facilities.

Financial Highlights

	Three months ended December 31	Nine months ended December 31
(Veresen's share; \$ Millions)	2015	2015
Hythe/Steepprock EBITDA	10	30
Dawson EBITDA	10	23
Corporate general and administrative	(2)	(5)
Depreciation and amortization	(9)	(26)
Interest and other finance	(6)	(19)
Unrealized loss on translation of US dollar debt	(12)	(37)
Unrealized gain on cross currency swap	11	32
Other foreign exchange	–	1
Net income (loss) before tax / equity income (loss)	2	(1)

During the nine months ending December 31, 2015, Veresen Midstream generated \$45 million of distributable cash and a net loss of \$1 million before tax, in line with expectations.

Hythe/Steepprock and Dawson generated \$30 million and \$23 million of EBITDA, respectively, for the period ended December 31, 2015. The EBITDA generated by Hythe/Steepprock is mainly comprised of the minimum volume and fee commitment provided by the MSA. Dawson's EBITDA is based on actual throughput being received from Encana and CRP and fee for service revenues governed under a long-term MSA.

On December 31, 2015, Veresen Midstream paid a distribution of \$23 million, of which our share is \$15 million. The PIK structure allowed us to receive two-thirds of the cash distributions while we were entitled to approximately 49.6% of the net income during the nine months ending December 31, 2015.

Results for the period ending December 31, 2015 include a \$32 million fair value gain on Veresen Midstream's cross currency swap, offset by a \$37 million foreign exchange loss on the revaluation of Veresen Midstream's US dollar denominated Term Loan (discussed in the *Financial Instruments* section of this MD&A) and the expensing of \$2 million of deferred financing costs resulting

from the re-pricing of Veresen Midstream's Term Loan in the second quarter. There were no operating earnings or distributions from Veresen Midstream during the first quarter of 2015 as its operating assets, including Hythe/Steeprock, were not acquired until March 31, 2015.

During the fourth quarter of 2015, Veresen Midstream paid a distribution of \$15 million. Hythe/Steeprock and Dawson both generated \$10 million of EBITDA, and net income includes an \$11 million fair value gain on Veresen Midstream's cross currency swaps and an \$12 million loss on the revaluation of its US dollar-denominated Term Loan.

Aux Sable

NGL Market Overview

	Three months ended December 31		Year ended December 31	
	2015	2014	2015	2014
Average USGC ethane margin (US\$/gallon)	0.03	(0.05)	0.03	(0.02)
Average USGC propane plus margin (US\$/gallon)	0.31	0.52	0.30	0.75
Average USGC propane (US\$/gallon)	0.42	0.77	0.46	1.04
Average Henry Hub natural gas (US\$/mmbtu)	2.24	3.75	2.61	4.34
Average Chicago Citygate natural gas (US\$/mmbtu)	2.16	3.90	2.69	5.57
Average WTI crude oil (US\$/bbl)	42.18	73.24	48.29	93.02
Average Chicago-AECO differential (\$/mmbtu)	0.42	0.88	0.80	1.61

U.S. Gulf Coast ("USGC") ethane margins remained weak throughout 2015 due to continued oversupply.

Propane inventory levels in the U.S. remained at elevated levels through 2015, depressing USGC propane plus margins relative to 2014. U.S. propane stocks ended 2015 at an estimated 93 million barrels, 21 million barrels above levels from the same period last year and 39 million barrels above the five-year average. Seasonal demand factors such as winter heating and crop drying were insufficient to work down high inventory levels. USGC propane prices averaged US\$0.42 per gallon in the fourth quarter of 2015 compared to US\$0.77 per gallon during the same period in 2014, reflecting the high inventory levels and downward pressure on natural gas liquids prices stemming from a steep decline in crude oil prices. USGC propane prices for the year decreased US\$0.58 compared to 2014.

Natural gas prices declined throughout the fourth quarter of 2015, reflecting high inventory levels resulting from strong North American natural gas production, despite lower prices and persistent warm temperatures during the winter months. The first quarter of 2014 experienced higher gas prices as a result of the extremely cold temperatures in the U.S. Mid-West. The Chicago Citygate gas price averaged US\$2.16 per mmbtu during the fourth quarter of 2015, decreasing US\$1.74 per mmbtu over the same period last year.

Operational Highlights

During the year ended December 31, 2015, Aux Sable processed 93% of the natural gas delivered by Alliance compared to 96% last year. The decrease primarily relates to bypassing volumes due to high inventory volumes, uneconomic margins and planned downtime.

Receipts into the Prairie Rose Pipeline in North Dakota averaged 101 mmcf/d during the year ended December 31, 2015, compared to 98 mmcf/d for the same period last year. The increase was primarily due to planned volume growth from the Bakken producers and extremely cold temperatures hampering producer field gathering systems early in the first quarter of 2014, partially offset by the August 2015 Alliance pipeline shutdown.

Propane plus sales volumes were 45.1 million mbbls/d for the year ended December 31, 2015 compared to 47.6 mbbls/d last year, driven by reinjection due to oversupply in the market and the Alliance pipeline shutdown in August. Aux Sable produced 21 mbbls/d of ethane during 2015 to satisfy certain commercial arrangements. Volumes in 2015 were lower than last year due to a continued market oversupply of ethane.

Financial Highlights

Components of Aux Sable Equity Income:

(Veresen's share; \$ Millions)	Three months ended December 31		Year ended December 31	
	2015	2014	2015	2014
Margin based lease revenues				
Amount generated during period	1	5	4	23
Margin recognized from prior period	–	3	–	–
(Unrecognized margin in period)	–	–	–	–
Amount recognized as revenue	1	8	4	23
Pipeline capacity margin	(6)	–	(14)	6
Other margin based activities	1	5	(2)	16
Fixed fee activities	10	9	39	35
General, administrative, operating and maintenance	(6)	(6)	(23)	(21)
Provision for potential customer settlement	(16)	–	(32)	–
Depreciation and amortization	(4)	(3)	(15)	(11)
Interest and other finance	–	–	–	–
Net income (loss) before tax / equity income (loss)	(20)	13	(43)	48

For the year ended December 31, 2015, Aux Sable generated \$11 million of distributable cash and \$43 million in net losses before tax, compared to \$57 million of distributable cash and \$48 million in net income before tax in 2014.

During 2015, Aux Sable's NGL Sales Agreement provided downside protection against the continued weak NGL market environment, delivering the fixed fee and covering the Channahon facility's operating costs with no meaningful margin based lease revenues being generated.

Losses were incurred this year with respect to Aux Sable's pipeline capacity business, due to temporary disruptions in pipeline takeaway capacity creating gas market supply demand imbalances during the third and part of the fourth quarter of 2015, and narrowing of the AECO-Chicago natural gas price differential. Last year saw the widening of the AECO-Chicago natural gas price differential in the first quarter of 2014, largely driven by the extreme cold temperatures in the U.S. Mid-West, resulting in higher pipeline capacity earnings in 2014.

Aux Sable's other margin-based activities decreased due to lower NGL fractionation margins realized at its Palermo Conditioning Plant in North Dakota.

In the fourth quarter of 2015, an additional \$16 million provision was recognized in respect of potential adjustments relating to Aux Sable customer obligations.

Fourth quarter distributable cash and net income decreased relative to the same period in 2014 due to the same factors discussed above. AECO – Chicago natural gas price differentials narrowed significantly in the fourth quarter of 2015 relative to the same period last year, resulting in losses in Aux Sable's pipeline capacity business.

Power Business

(\$ Millions, except where noted)	Three months ended December 31		Year ended December 31	
	2015	2014	2015	2014
Gain (loss) on interest rate hedges	5	(4)	(1)	(12)
Other equity income	3	2	5	10
Equity Income (loss)	8	(2)	4	(2)
EBITDA	15	9	46	40
Depreciation and amortization	(10)	(7)	(33)	(27)
Interest and other finance	(3)	(3)	(10)	(13)
Foreign exchange and other	3	–	3	–
Net income (loss) before tax	13	(3)	10	(2)
Distributable cash	14	8	43	47
Volumes (GWh)				
Gross	190	182	716	766
Net	156	151	603	638

Operational Highlights

Our power facilities performed reliably in 2015. We completed construction of our Ontario-based St. Columban and Grand Valley Phase III wind projects and Dasque / Middle BC run-of-river hydro project during the year; all facilities are operating as expected.

Financial Highlights

For the year ended December 31, 2015, our power facilities generated \$43 million of distributable cash, a \$4 million decrease compared to last year. The decrease was mainly attributable to the sale of our U.S. gas-fired facilities in January 2015 and the receipt of a \$4 million retroactive adjustment in relation to York Energy Centre's power purchase agreement with the Ontario Power Authority ("OPA") during the second quarter of 2014, partially offset by the incremental earnings from our new wind and run-of-river hydro projects commencing operations in 2015.

For the year ended December 31, 2015, net income before tax was \$10 million compared to a net loss of \$2 million in 2014. Higher operating earnings from our facilities during the year and lower losses on interest rate hedges was partially offset by incremental depreciation on our new facilities and the receipt of the \$4 million retroactive adjustment from the OPA in the second quarter of 2014.

Distributable cash for the quarter ending December 31, 2015 increased by \$6 million due to incremental cash flows from our new facilities. The U.S. gas-fired facilities sold in the first quarter did not have a material impact on fourth quarter 2014 cash flows. Net income for the quarter ending December 31, 2015 increased due to higher operating earnings and gains on interest rate hedges, partially offset by incremental depreciation on our new facilities.

Veresen – Corporate and Project Development

(\$ Millions)	Three months ended December 31		Year ended December 31	
	2015	2014	2015	2014
Equity loss	4	4	14	12
General and administrative	2	7	22	29
Project development	29	20	85	79
Depreciation and amortization	1	–	3	2
Interest and other finance	7	13	38	41
Foreign exchange and other	1	(35)	(5)	(41)
Net expenses before tax	44	9	157	122
Distributable cash	(9)	(18)	(53)	(66)

For the year ended December 31, 2015, we incurred \$157 million of net corporate expenses before taxes, a \$35 million increase compared to the previous year. The increase was due to a \$39 million pre-tax gain on forward foreign exchange contracts entered into to manage the foreign exchange exposure related to the Ruby acquisition in the fourth quarter of 2014 and higher project development spending related to our Jordan Cove LNG project. This was partially offset by lower general and administrative costs driven by the revaluation of our long-term incentive plans.

Interest was lower in the fourth quarter of 2015 due to the repayment of the Acquisition Facility throughout 2015.

Taxes

(\$ Millions)	Three months ended December 31		Year ended December 31	
	2015	2014	2015	2014
Net income from continuing operations before tax	18	48	113	103
Current tax	(6)	(10)	(37)	(30)
Deferred tax	9	(3)	18	5
Total tax	3	(13)	(19)	(25)
Effective rate	(16.7)%	27.1%	16.8%	24.3%

Our effective tax rate for 2015 is lower than in 2014 due to a recovery of prior year foreign taxes and Alliance's discontinuation of rate-regulated accounting. Effective January 1, 2016, we implemented a U.S.-based organizational restructuring which effectively eliminates cash taxes, with the exception of Part VI.1 taxes on our Preferred Share dividends, for approximately the next five years.

LIQUIDITY AND CAPITAL RESOURCES

(\$ Millions, except where noted)	Three months ended December 31		Year ended December 31	
	2015	2014	2015	2014
Cash flows				
Operating activities	76	71	287	215
Investing activities	(24)	(1,689)	366	(1,794)
Financing activities	(105)	1,645	(658)	1,606
	December 31, 2015		December 31, 2014	
Cash and short-term investments	58		51	
Capitalization				
Senior debt ⁽¹⁾	1,100	26%	1,811	42%
Shareholders' equity	3,087	74%	2,532	58%
	4,187	100%	4,343	100%

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

In 2015 we advanced our goal of reducing leverage and borrowing costs and improving liquidity. As discussed below under Equity Financing Activities and Debt Financing Activities, we used cash proceeds from the Veresen Midstream transaction and issuance of preferred shares to repay a portion of the Acquisition Credit Facility. As a result of these transactions, we reduced our debt to total capitalization ratio from 42% at the end of 2014 to 26% at the end of 2015.

We expect to continue to utilize cash from operations, drawings on our Revolving Credit Facility and cash raised through our DRIP to fund liabilities as they become due, finance capital expenditures, fund debt repayments, pay dividends and to provide flexibility for new investment opportunities. As at December 31, 2015, we had \$750 million of committed credit facilities of which \$169 million was drawn, including \$21 million in letters of credit.

At December 31, 2015, we had cash and short-term investments of \$58 million (December 31, 2014 – \$51 million) and non-cash working capital deficit of \$17 million (December 31, 2014 – \$22 million excess).

Investing Activities

For the year ended December 31, 2015, we generated \$366 million of cash from investing activities, compared to \$1,794 million of cash used in 2014 to fund our investing activities. Significant investing activities for the year ended December 31, 2015 and 2014 are presented in the table below.

(\$ Millions)	Year ended December 31	
	2015	2014
Acquisitions and dispositions		
Ruby acquisition, net of gains on forward foreign exchange contracts	–	(1,597)
Proceeds from sale of assets	420	19
	420	(1,578)
Investments in jointly-controlled businesses		
Equity contributions	(60)	(74)
Return of capital	30	11
	(30)	(63)
Capital expenditures		
Midstream	(9)	(14)
Dasque-Middle run-of-river hydro facility	(6)	(47)
St. Columban wind project	(29)	(83)
Operating power facilities	(7)	(2)
Other capital expenditures	(7)	(2)
	(58)	(148)
Other	–	(1)
Cash provided (used) in discontinued operations	34	(4)
Investing	366	(1,794)

Financing Activities

For the year ended December 31, 2015, we used \$658 million of cash to settle financing obligations, compared to \$1,606 million of cash inflows in 2014. Financing activities for the year ended December 31, 2015 and 2014 included:

(\$ Millions)	Year ended December 31	
	2015	2014
Common Share dividend payments	(107)	(156)
Common Share issuance, net of issue costs	–	1,157
Net draws (repayments) on Revolving Credit Facility	25	(41)
Senior debt repayments	(738)	(262)
Senior debt issued, net of issue costs	–	920
Preferred Shares issued, net of issue costs	194	–
Preferred Share dividend payments	(24)	(16)
Other	(8)	4
Financing	(658)	1,606

Equity Financing Activities

Commencing with the cash dividend payable to shareholders of record on October 31, 2014, eligible shareholders may participate in the Premium Dividend™ component of the Dividend Reinvestment Plan (“DRIP”) which will entitle such shareholders to reinvest their dividends in Common Shares issued from treasury and to have such Common Shares exchanged for a premium cash payment equal to 102% of the cash dividend that such shareholders would otherwise be entitled to receive on the applicable dividend payment date. The availability of the Premium Dividend (™ Trademark of Canaccord Genuity Corp.) to shareholders has substantially increased participation in our DRIP program, proving us with additional cash to fund our various growth initiatives.

On April 1, 2015 we issued 8.0 million Cumulative Redeemable Preferred Shares, Series E (“Series E Preferred Shares”) at a price of \$25.00 per share for total gross proceeds of \$200 million.

The Series E Preferred Shares are redeemable by us, in whole or in part, on June 30, 2020 and on June 30 of every fifth year thereafter at a price of \$25.00 per share plus accrued and unpaid dividends.

Debt Financing Activities

On March 31, 2015 we used the \$420 million in cash we received from Veresen Midstream to partially repay our Acquisition Credit Facility related to the Ruby acquisition in the fourth quarter of 2014. Proceeds from our April 1, 2015 issuance of the Series E Preferred Shares were used to repay an additional portion of the Acquisition Credit Facility.

On July 31, 2015, our Revolving Credit Facility was increased from \$550 million to \$750 million and the term extended such that it now matures on May 31, 2019. In August 2015, we drew from our Revolving Credit Facility to repay the remaining \$112 million outstanding balance of the Acquisition Credit Facility.

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.

The holders of Series E 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 June 30, 2020 and every five years thereafter based on then-market rates. The holders of Series E Preferred Shares will have the right to convert all or any part of their shares into Cumulative Redeemable Preferred Shares, Series F (“Series F Preferred Shares”), subject to certain conditions, on June 30, 2020, and on June 30 of every fifth year thereafter. The holders of Series F Preferred Shares will be entitled to receive quarterly floating rate cumulative dividends, as and when declared by our Board of Directors of Veresen, at a rate 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 elsewhere in this MD&A.

Dividends Paid

For the year ended December 31, 2015 we declared dividends on our common shares of \$291 million (2014 – \$227 million), of which \$109 million (2014 – \$146 million) was paid to common shareholders in cash and \$182 million (2014 – \$81 million) was paid in Common Shares issued under our DRIP.

Restrictions on Dividends

Our ability to pay dividends to common shareholders is dependent on the applicable terms of certain financing and security agreements. Our Revolving Credit Facility restricts us from paying dividends to common shareholders when an Event of Default has occurred or is continuing. On December 31, 2015 no Event of Default under any of these arrangements had occurred or was continuing that would restrict dividends being paid.

Our investments in our operating businesses have been made through debt and equity investments in subsidiary partnerships and corporations. In general, other than covenant restrictions contained in applicable debt arrangements, 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.

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

(\$ Millions)	Three months ended December 31		Year ended December 31	
	2015	2014	2015	2014
Cash from operating activities	76	71	287	215
Net income attributable to Common Shares	14	21	60	52
Dividends paid/payable	73	66	291	227
Less dividends paid in Common Shares under DRIP	(45)	(42)	(182)	(81)
Net dividends paid/payable	28	24	109	146
Excess of cash from operating activities over net dividends paid/payable	48	47	178	69
Deficiency of net income attributable to Common Shares over net dividends paid/payable	(14)	(3)	(49)	(94)

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 year ended December 31, 2015, equity income from our Power business includes a pre-tax \$1 million unrealized mark-to-market loss associated with interest rate hedges. For 2014, equity income includes a pre-tax \$12 million unrealized mark-to-market loss (\$9 million after tax).

During the first quarter of 2015, Veresen Midstream entered into a cross currency swap to manage both interest rate and foreign exchange rate exposures on its US\$575 drawn Term Loan B. For the year ended December 31, 2015, equity income from Veresen Midstream includes a pre-tax \$32 million unrealized mark-to-market gain (\$23 million after tax) associated with the cross currency swap.

The following table summarizes our financial instrument carrying and fair values as at December 31, 2015:

(\$ Millions)	Financial assets at amortized cost	Financial liabilities at amortized cost	Non-financial instruments	Total	Fair value ⁽¹⁾
Assets					
Cash and short-term investments	58			58	58
Restricted cash	7			7	7
Distributions receivable	52			52	52
Accounts receivable and other	23		5	28	23
Due from jointly-controlled businesses	50			50	50
Investments held at cost	1,981			1,981	2,010
Other assets	12		1	13	12
Liabilities					
Accounts payable and other		65		65	65
Dividends payable		25		25	25
Senior debt		1,100		1,100	1,143
Other long-term liabilities		9	27	36	9

(1) Fair value excludes non-financial instruments.

The following table summarizes our financial instrument carrying and fair values as at December 31, 2014:

(\$ Millions)	Financial assets at amortized cost	Financial liabilities at amortized cost	Non-financial instruments	Total	Fair value ⁽²⁾
Assets					
Cash and short-term investments	51			51	51
Restricted cash	5			5	5
Distributions receivable	46			46	46
Accounts receivable and other	55			55	55
Due from jointly-controlled businesses	44			44	44
Assets held for sale	6		33	39	6
Investments held at cost	1,660			1,660	1,660
Other assets	1		17	18	1
Liabilities					
Accounts payable and other		69	2	71	69
Dividends payable		8		8	8
Liabilities associated with assets held for sale		4		4	4
Senior debt		1,811		1,811	1,864
Other long-term liabilities		14	39	53	14

(2) Fair value excludes non-financial instruments.

For the years ended December 31, 2015 and 2014 the following amounts were recognized in income:

(\$ Millions)	2015	2014
Total interest expense, recorded with respect to other financial liabilities, calculated using the effective rate method	53	59

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, distributions receivable, receivables and accrued receivables, due from jointly-controlled businesses, other assets, payables, interest payable, accrued payables, dividends 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 value of the investment held at cost is based on a number of factors, including the present value of anticipated distributable cash flows to be produced from the underlying operations of the Ruby investment. Assessing these cash flows required the use of assumptions related to the future demand for Ruby's operations, forecasted commodity prices and interest rates, anticipated economic conditions, timing of conversion of the preferred interest into a common equity interest, and other inputs, many of which are not available as observable market data. The fair values of senior debt are 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.

US GAAP 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.

We have categorized senior debt as Level 2 and investments held at cost as Level 3.

Financial instruments measured at fair value as of December 31, 2015 were:

(\$ Millions)	Level 1	Level 2	Level 3	Total
Cash and short-term investments		58		58
Restricted cash		7		7

Maturity Analysis of Financial Liabilities

The tables below summarize our financial liabilities into relevant maturity groupings based on the remaining period at the balance sheet date to the contractual maturity date. The amounts disclosed in the table are the undiscounted cash flows.

The following table summarizes the maturity analysis of financial liabilities as of December 31, 2015:

(\$ Millions)	<1 year	1-3 years	4-5 years	Over 5 years
Accounts payable and other	65			
Dividends payable	25			
Senior debt	13	640	288	159
Other long-term liabilities		9		

The following table summarizes the maturity analysis of financial liabilities as of December 31, 2014:

(\$ Millions)	<1 year	1-3 years	4-5 years	Over 5 years
Payables, interest payable and accrued payables	71			
Dividends payable	8			
Liabilities associated with assets held for sale	4			
Senior debt	11	1,174	394	232
Other long-term liabilities		14		

CONTRACTUAL OBLIGATIONS AND COMMITMENTS

The Court of Appeal for Ontario denied our appeal of a portion of the decision issued earlier this year by an Ontario court in respect of an option held by Energy Fundamentals Group Inc. (“EFG”) to acquire up to 20% of our equity interest in the Jordan Cove LNG terminal. We will not appeal this matter further and will determine the information to be provided to EFG in connection with the option in compliance with the terms of the original decision.

On April 15, 2015, Aux Sable received a Notice and Finding of Violation from the United States Environmental Protection Agency (“EPA”) for exceedances of permitted limits for Volatile Organic Compounds at Aux Sable’s Channahon, Illinois Facility. Aux Sable is engaged in discussions with the EPA to resolve the matter. The initial EPA proposal confirms the settlement amount will not be material.

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

(\$ Millions)	Total	Payments due by period			
		Less than 1 year	1-3 years	4-5 years	After 5 years
Senior debt	1,100	13	640	288	159
Operating leases	50	6	10	10	24
Other long-term obligations	37	1	9	–	27
	1,187	20	659	298	210

RISKS

The Company’s business objectives, financial condition, future prospects and reputation are impacted by risks and uncertainties. Our objective is to manage these risks and uncertainties in a balanced manner, seeking to mitigate risk while maximizing total shareholder returns. It is senior management’s and the applicable business functional head’s responsibility to identify and to effectively manage the risks of each business including the development of risk management strategies, policies, processes and systems. Risk management strategies include the use of a prudent third party insurance program, financial and physical hedging of specific risks, and the development of internal policies and practices to optimize functions such as project management, safety, environmental and regulatory compliance, and reputation management. The company is exposed to common business risks as well as business risks associated with our Pipeline, Midstream and Power businesses. Some risks and uncertainties are market-related systemic risks, while others are either common to all of our businesses or unique to our Pipeline, Midstream or Power businesses. The more significant business risks and uncertainties affecting our businesses are set out below.

Business-Specific Risks

Risks Specific to Our Pipeline Business

Extension of Transportation Contracts; Supply and Demand

Each of Alliance, Ruby, and AEGS derive revenues from transportation contracts with varying terms. Alliance contracts have an average contract term length of five years. Ruby's weighted average primary contract term extends for more than seven years from November 2015. AEGS has primary terms ending in three years. 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 for Alliance and AEGS, respectively, produced from western Canada and natural gas produced from the U.S. Rockies for Ruby, and the ability of these pipelines to compete at the supply and demand ends of their respective systems.

Supply depends upon a number of factors including the:

- level of exploration, drilling, reserves and production of natural gas;
- price of natural gas and NGLs;
- 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;
- regulatory environments in Canada and the United States; and
- transportation pricing of competitors.

Demand for natural gas depends, among other things, on weather, price and consumption, and alternative energy sources. Upon maturity of the existing transportation contracts, Alliance and Ruby face competition in pipeline transportation to the Chicago area and Pacific Northwest delivery points, respectively, from both existing pipelines and proposed projects. Any new or upgraded pipelines could either allow shippers and competing pipelines to have greater access to natural gas markets served by Alliance and Ruby and the pipelines to which they are connected. Competitors could further offer natural gas transportation services that are more desirable to shippers than those provided by Alliance or Ruby due to location, facilities or other factors. In addition, competing pipelines could charge rates or provide transportation services to locations that result in greater net profit for shippers, which could result in reduced revenues and cash flows for Alliance and Ruby.

With respect to Alliance, excess natural gas pipeline capacity out of the Western Canadian Sedimentary Basin and a sustained period of low natural gas and crude prices could result in a significant reduction or deferral of investment in upstream gas development, and could negatively impact our ability to re-contract Alliance. Additionally, increased supply from new shale developments including the Marcellus and Utica shale plays could displace gas from the WCSB to the United States Midwest, further increasing re-contracting risk.

With respect to Ruby, the level of commitment for transport on the Ruby pipeline may be negatively affected by reduced supply in the U.S. Rockies due to low natural gas prices. U.S. Rockies natural gas production also has transportation options out of the basin toward the midwestern and northeastern U.S. on competing pipelines. Although current U.S. supply/demand dynamics indicate that future U.S. Rockies supply will favour a U.S. west coast alternative, there is no assurance that U.S. west coast demand and/or U.S. west coast export opportunities will materialize to the degree necessary to ensure that Ruby can access sufficient volumes at sufficient prices to maintain revenues and cash flow. This risk is partially mitigated by our convertible preferred interest ownership in Ruby which provides for a fixed annual distribution before any distributions are made to the holders of common shares.

With respect to AEGS, two large petrochemical companies, each of whom own and operate world-class petrochemical facilities in Alberta, drive the demand for ethane shipped on AEGS. 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. This risk is mitigated by AEGS' take-or-pay contracts with shippers until 2018. Further, AEGS is the only Pipeline in Alberta capable of transporting Ethane.

We can give no assurance as to the abilities of Alliance, AEGS, and Ruby to replace contract commitments from shippers or to negotiate terms similar to those under current transportation contracts upon their expiry.

Rate Regulation

Alliance is subject to Canadian and United States federal regulation by the NEB and the FERC, respectively. AEGS is subject to Canadian provincial regulation by the Alberta Utilities Commission. Ruby is subject to United States federal regulation by the FERC. The ability of our pipelines 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; and
- any other adverse change to the rates on the respective rate structures or terms and conditions of service.

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 fail to provide heat content management services to Alliance U.S. for any reason, the 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 Veresen Midstream

Natural Gas Throughput

Facilities within Veresen Midstream face the risk of lower throughput due to potential production declines, particularly at times of lower drilling activity in the industry. Earnings and cash flows from the Hythe/Steepprock assets are insulated from volume risk as the long-term Hythe/Steepprock MSA with Encana is a take-or-pay contract. The Dawson Assets have a 30-year fee-for-service arrangement. The risk of lower throughput for the Dawson Assets is mitigated by commercial guarantees including financial protections. Under the arrangement, unit capital fees are set for individual components in order to achieve a target rate of return based on invested capital and expected throughput. Facility fees will be fixed 12 months after commercial operations, and gathering fees will be reset at defined periods based on actual throughput. Another financial protection is a mechanism which provides for the payout of minimum costs associated with certain gathering and compression assets. The potential payout of minimum costs will be assessed in the eighth year of the assets' service period and is based on whether there is an overall shortfall of total system cash flows from natural gas gathered and compressed under certain service agreements. The potential payout amount can be reduced in the event Veresen Midstream markets unutilized capacity to third party users.

Volume risk is mitigated by the continued high level of exploration and development activity in the Montney production area of British Columbia and Alberta, where the Veresen Midstream assets are located, an area widely recognized as one of North America's most promising and competitive natural gas resource plays. In addition, commercial efforts are underway to attract further third party volumes to Veresen Midstream's facilities.

Risks Specific to the Power Business

Gas Supply

The operation of our gas-fired power generation and London district energy facilities requires the delivery of natural gas. If there is any interruption in the provision of natural gas for any of these facilities, the ability to generate electricity and, in the case of the cogeneration facilities, steam or distilled water, will be negatively affected and may have a negative impact on our earnings and cash flows. These facilities are dependent on pipeline deliveries of natural gas and a functioning and integrated North America supply grid. We have attempted to mitigate this risk by purchasing natural gas at major supply hubs and entering into firm delivery contracts with major transporters of natural gas.

Market Pricing Risks

Commodity Price

Our earnings and cash flows are subject to movements in certain commodity prices. Our most significant current commodity price exposures are in Aux Sable's midstream 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 specification NGL products. 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. Aux Sable's NGL Sales Agreement is with an international, integrated energy company, which mitigates the downside risk of low NGL prices while retaining significant upside when NGL margins are favourable.

Based on our plan assumptions, if propane plus fractionation spreads strengthen by ten cents per U.S. gallon, or weaken by five cents, the impact on 2016 estimated distributable cash would be \$12 million and \$(5) million, respectively.

Aux Sable Canada may have gas positions in multiple locations on the Alliance pipeline as a result of the RGP agreements. In conjunction with its RGP agreement contracting, Aux Sable has developed gas marketing, transportation and commercial arrangements to support and manage the supply of liquids-rich natural gas to the Channahon Facility. This business may involve Aux Sable purchasing and selling natural gas and/or holding transportation on Alliance pipeline or adjacent transportation systems, in order to mitigate potential exposure to commodity prices or basis differentials. Basis differentials are impacted by a number of factors, including weather events and forecasts, regional supply/demand dynamics, operational issues on adjacent transportation systems and overall pricing of North American natural gas. Aux Sable continues to implement strategies to minimize the financial impact of these commodity price and basis exposures.

Based on our plan assumptions, if the Chicago-AECO basis differential widens or narrows by US\$0.15 per mmbtu, the impact on 2016 distributable cash would be \$7 million and \$(11) million, respectively.

We are also exposed to movements in energy costs at some of our power facilities where the cost of fuel is not fully recoverable. A significant portion of earnings from our Power business is comprised of fixed capacity payments and, as such, these earnings are not significantly influenced by variability in the commodity price of electricity or natural gas.

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 contractual arrangements qualify for hedge accounting treatment, 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 debt and equity from banks and the 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 shareholder 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. Standard & Poor's Rating Services LLC and DBRS Limited have both recently reaffirmed Veresen's BBB Stable corporate credit ratings; and
- sufficient liquidity through cash balances, excess cash flow, committed revolving credit facilities, and our DRIP 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 unfavourable. We have summarized recent changes to 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. In 2014, we entered into forward foreign exchange contracts to manage the foreign exchange exposure relating to the Ruby acquisition. To date, we have not entered into any other foreign currency hedges to reduce our currency risk in respect of our net U.S. dollar investment.

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

On December 31, 2015, approximately 61% of our total assets were denominated in U.S. dollars. For the year ended December 31, 2015, we recorded an unrealized foreign exchange gain of \$424 million in other comprehensive income on the re-translation of our U.S. net assets. At December 31, 2015, 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 \$20 million, \$1 million, and \$2 million, respectively, lower or higher.

Interest Rate

We have financed portions of our operations 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 primarily comprised of drawdowns under committed bank credit facilities. 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. From an accounting perspective, to the extent these hedges are deemed to be effective, we record any such gains or losses in other comprehensive income. On December 31, 2015, 13% of our consolidated long-term debt was floating-rate debt. At December 31, 2015, 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 million lower or higher.

As part of York Energy Centre's and Grand Valley's debt financings in 2010 and 2015, respectively, they in aggregate entered into three interest rate hedges. These hedges were entered into to manage the exposure to changes in interest rates whereby York Energy Centre and Grand Valley receive variable interest rates and pay fixed interest rates. As at December 31, 2015, two interest rate hedges remained. Future changes in interest rates will affect the fair value of the remaining hedge, impacting the amount of unrealized gains or losses recognized in the period through equity income. For the three months and twelve months ended December 31, 2015, equity income includes a \$5 million unrealized mark-to-market gain and \$1 million unrealized mark-to-market loss, respectively, associated with these hedges.

Common Business Risks

Investment

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

- the availability of potential projects where we have a strategic advantage;
- securing necessary regulatory and environmental approvals and permits;
- integrating acquisitions in an optimal manner and achieving expected synergies;
- accessing capital on a cost-competitive basis;
- completing late-stage development projects on time and within budget; and
- achieving 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. We also use a structured project gate process that ensures that a detailed risk assessment is performed, and the use of detailed financial modeling and an assessment of the project's impact on our financial results, risk profile and capital structure. Senior management and the applicable board of directors review every significant investment to ensure it meets our key investment criteria. These activities require substantial management expertise and resources, which, from time to time, may strain our ability to manage existing operations and possibly other strategic growth 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 a diversified set of counterparties, a significant number of which are currently 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.

Over the past year, energy prices have seen significant declines and volatility that affected companies throughout the oil and gas industry. A reduction in producers' capital and operating budgets and the impact of reduced revenues on corporate liquidity positions has resulted in an increase in potential credit risk to Alliance and Ruby. There is a risk that suitable replacement shippers could not be found. Requiring shippers to provide letters of credit or other suitable security, unless the shippers maintain specified credit ratings or a suitable financial position, mitigates Alliance's and Ruby's exposure. As at December 31, 2015, 58% of firm capacity on the Alliance pipeline is contracted to shippers who either have an investment grade rating or acceptable credit status. Ruby's largest shipper is a major Northern Californian utility. Investment-grade shippers represent 90% of Ruby's contracted capacity.

In the case of AEGS, we are primarily dependent on two customers, both large petrochemical companies with world-scale petrochemical facilities located in Alberta. AEGS represents a critical component in securing ethane feedstock for these petrochemical facilities. In the case of Veresen Midstream, we are currently dependent on Encana and CRP, a partnership between Encana and Cutbank Dawson Gas Resources Ltd., a subsidiary of Mitsubishi Corporation. Mitsubishi possesses an investment-grade credit rating. Encana is currently rated as investment grade with Standard & Poor's (BBB) and Dominion Bond Rating Service (BBB), while Moody's Investor Service has rated Encana as Ba2. In the case of Aux Sable's midstream business, earnings and cash flows are primarily dependent upon the long-term NGL Sales Agreement with 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, gas-fired and BC run-of-river hydro 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 where appropriate; and
- using contractual arrangements 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.

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 third party insurance coverage at industry acceptable levels in the case of an incident. However, there can be no assurance that these measures will be effective in preventing events that adversely impact the operations of our businesses or that insurance proceeds will be adequate to cover lost earnings and cash flows.

Competition

All of our businesses participate in competitive markets and compete with other companies. Substantially 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.

We also compete with other businesses for growth and business opportunities, which could impact our ability to grow through acquisitions.

Environmental, Health and Safety

Our businesses are subject to extensive federal, provincial, state, and local environmental, health and safety laws and regulations typical for the industries and jurisdictions within which they operate, including requirements for compliance obligations pertaining to discharges to air, land and water. Our facilities could experience environmental, health and safety incidents including spills, emission exceedances, or other unplanned events that could result in:

- fines or penalties;
- operational interruptions;
- physical injury to our employees, contractors, or general public;
- 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 nitrous oxides and greenhouse gas emissions, which could result in more stringent and costly compliance requirements.

The Alberta government announced changes to their Specified Gas Emitters Regulation (SGER) in June of 2015, which maintained its requirement that facilities annually emitting 100,000 tonnes or more of greenhouse gas emissions (“GHG”) reduce their site-specific emissions intensity by 12%. However, this target increases to 15% as of January 1, 2016 and 20% as of January 17, 2017. Alliance has mitigated the impacted of the SGER program by building a system that is more modern and efficient than older, conventionally designed natural gas pipelines. While GHG emissions have been reduced by using high efficiency gas turbines, achieving the mandated GHG reductions will be difficult to achieve without the need to either purchase Alberta Climate Change Fund credits at \$15 per credit (1 credit = 1 tonne of CO₂ emission reductions) or to purchase offsets from qualified projects.

The cost to purchase such credits is not expected to be material to us. At present, the change to SGER will not have an impact on AEGS and Veresen Midstream's Hythe gas processing facility as these facilities annually emit less than 100,000 tonnes of GHGs.

We are not aware of any other federal, provincial or state regulations governing GHG emissions that would materially impact our facilities at this time.

Our businesses may also be subject to opposition by special interest groups which could result in schedule delays and increased costs. These special interest groups have the ability to participate in various regulatory processes and proceedings in an effort to influence the outcome.

As part of the consultative process, our businesses work with Aboriginal groups, local landowners, special interest groups, counties, and municipalities. Stakeholder engagement is aimed at providing interested members of the public with information regarding our businesses and addresses their concerns. Stakeholder consultation does not assure that all risks associated with community opposition can be mitigated.

On April 15, 2015, Aux Sable received a Notice and Finding of Violation from the EPA for exceedances of permitted limits for Volatile Organic Compounds at Aux Sable's Channahon, Illinois Facility. Aux Sable is engaged in discussions with the EPA to resolve the matter. The initial EPA proposal confirms the settlement amount will not be material. We are unaware of any other outstanding orders, fines, penalties or litigation for our businesses related to EH&S.

The EH&S Committee reports to our Board of Directors to provide corporate oversight regarding EH&S compliance for our businesses. Alliance and Aux Sable also have EH&S Committees which report to their respective board of directors. Through regular reporting, the EH&S Committees ensure compliance with our EH&S corporate policy, including compliance 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, and practices, including performance targets and reporting to senior management. Our policies, programs and practices are managed by experienced personnel and periodically reviewed and modified to ensure they comply 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, with insurers consistent with industry best practice. 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

Many of our businesses and material assets 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 100% approval of the owners. While we believe we have prudent governance and contractual rights in place, there can be no assurance that we will not encounter disputes with partners that may impact operations or cash flows.

Third Party Operators

Certain of our assets are operated by unrelated third party entities. The business success of these assets is to some extent dependent on the expertise and ability of these entities to successfully operate and maintain the assets. While we rely on the judgement and operating expertise of these operators, we mitigate this risk by exercising prudent management oversight and relying on operators that have proven track records of success in operating like assets.

Development Risk

In the normal course of business growth, we participate in the design, construction and operation of new facilities. In developing new projects, we may be required to incur significant preliminary engineering, environmental, permitting and legal-related expenditures prior to determining whether a project is feasible and economically viable. In the event a project is not completed or does not operate at anticipated performance levels, we may be unable to recover our investment. There is a risk that projects under development or construction may not be completed on time, on budget or at all. Projects may have delays or increased costs due to many factors.

From time to time, due to long lead times required for ordering equipment, we may place orders for equipment and make deposits thereon or advance projects before obtaining all requisite permits and licenses. We only take such actions where we reasonably believe such licenses or permits will be forthcoming in due course prior to the requirement to expend the full amount of the purchase price. However, any delay in permitting or failure to obtain the necessary permits could adversely affect our earnings and cash flows.

Projects are approved for development on a project-by-project basis after considering strategic fit, the inherent risks, and expected financial returns. A structured gating process that evaluates projects at various stages in the development process is conducted for every project. We believe this approach to project development, combined with an experienced management team, staff and contract personnel, minimizes development costs and execution risk.

CRITICAL ACCOUNTING POLICIES

Alliance's collection of abandonment costs is subject to rate regulation in Canada. Our consolidated financial statements are prepared in accordance with US 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 were recognized in equity income from Alliance differently than would otherwise be expected under US GAAP applicable to non-regulated businesses.

CRITICAL ACCOUNTING ESTIMATES

The preparation of our consolidated financial statements requires us to make judgements, estimates and assumptions about future events when applying US 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 more detailed disclosures of our significant accounting policies.

Impairment of Long-lived Assets, Investments in Jointly-Controlled Businesses and Investments Held at Cost

We evaluate, at least annually, our long-lived assets, investments in jointly-controlled businesses and investments held at cost 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.

On January 8, 2015, we closed the sale of our gas-fired generation facilities located in Colorado and California for a sale price of US\$27 million. As a result, we recognized a \$12 million impairment loss in the fourth quarter of 2014. We also recognized a \$5.0 million impairment loss on land we hold in Ontario.

We did not recognize any impairments of our long-lived assets, investments in jointly-controlled businesses or investments held at cost in 2015.

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. 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 comprehensive 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 the AEGS pipeline system, Veresen Midstream, and the EnPower, East Windsor Cogeneration, Furry Creek, Clowhom and St. Columban power facilities.

With respect to our jointly-controlled businesses, Aux Sable's Septimus and Heartland facilities, and the NRGreen and Grand Valley power facilities have each recognized provisions for asset retirement obligations. Aux Sable has not recognized a provision for asset retirement obligations in respect of its U.S.-based assets as the expected legal obligations are not material. Alliance has not recognized an asset retirement obligation provision for the Alliance pipeline. It is not currently possible to make a reasonable estimate of the fair value of the liability for the Alliance pipeline due to the indeterminate timing and scope of the asset retirement. The NEB's Abandonment Funding Initiative, previously discussed in the *Description of Business* section of this MD&A, addresses the need for a collection method for funding pipeline abandonment costs. The NEB's initiative is not a method for determining the timing of retirement obligations. However, in the event the initiative results in a reasonable estimate of asset retirement obligations for accounting purposes, financial statement recognition of those obligations may be made in future periods. As a result, regulatory assets and liabilities may be recognized to the extent the timing of recovery from shippers differs from the recognition of abandonment costs for accounting purposes. 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 net income.

NEW ACCOUNTING STANDARDS

Effective January 1 2015, we adopted Accounting Standards Update ("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 was applied prospectively and did not have a material impact.

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. In August 2015, the FASB issued ASU 2015-014, *"Revenue from Contracts with Customers: Deferral of the Effective date"*. This ASU amends the effective date of Update 2014-09 for all entities by one year. We are currently evaluating the impact of the standard.

In June 2014, the FASB issued ASU 2014-10, *"Development Stage Entities: Elimination of Certain Financial Reporting Requirements, Including an Amendment to Variable Interest Entities Guidance in Topic 810, Consolidation"*. This ASU eliminates the concept of a development-stage entity from US GAAP along with the associated presentation and disclosure requirements for development-stage entities. The removal of the development stage entity reporting requirements is effective for annual reporting periods beginning after December 15, 2014 and is not expected to have a material impact to us. The consolidation guidance was also amended to eliminate the development stage entity relief when applying the variable interest entity model and evaluating the sufficiency of equity at risk. We are currently evaluating the impact of the amendment to the consolidation guidance, which is effective for annual reporting periods beginning after December 15, 2015. The new standard requires these amendments be applied retrospectively.

In November 2014, the FASB issued ASU 2014-16, *“Derivatives and Hedging.”* This ASU provides guidance to clarify the criteria in evaluating the economic characteristics and risks of a host contract in a hybrid financial instrument that is issued in the form of a share. This guidance is effective for annual and interim periods beginning after December 15, 2015, and is to be applied prospectively. We are currently evaluating the impact of the standard.

In January 2015, the FASB issued ASU 2015-01, *“Income Statement – Extraordinary and Unusual Items”*. This ASU simplifies income statement classification by removing the concept of extraordinary items from US GAAP. This guidance is effective for annual and interim periods beginning after December 15, 2015, and may be applied prospectively or retrospectively. We are currently evaluating the impact of the standard.

In February 2015, the FASB issued ASU 2015-02, *“Consolidation: Amendments to the Consolidation Analysis”*. This ASU amends the current consolidation guidance, specifically the guidance in determining whether or not an entity is a variable interest entity. This guidance is effective for annual and interim periods beginning after December 15, 2015, and may be applied on a full or modified retrospective basis. We are currently evaluating the impact of the standard.

In April 2015, the FASB issued ASU 2015-03, *“Interest – Simplifying the Presentation of Debt Issuance Costs”*. This ASU changes the presentation of debt issue costs in financial statements. Under the ASU, an entity presents such costs in the balance sheet as a direct reduction from the related debt liability rather than as an asset. Amortization of the costs is reported as interest expense. This guidance is effective for annual and interim periods beginning after December 15, 2015, and is to be applied retrospectively. We are currently evaluating the impact of the standard.

In June 2015, the FASB issued ASU 2015-010, *“Technical Corrections and Improvements”*. This ASU represent changes to clarify the Codification, correct unintended application of guidance, or make minor improvements to the Codification that are not expected to have a significant effect on current accounting practice. This guidance is effective for annual and interim periods beginning after December 15, 2015. We are currently evaluating the impact of the standard.

In November 2015, the FASB issued ASU 2015-017, *“Income Taxes: Balance Sheet Classification of Deferred Taxes”*. This ASU changes the classification of deferred tax liabilities and assets. Under the ASU, an entity classifies deferred tax liabilities and assets as non-current in the statement of financial position. This guidance is effective for annual and interim periods beginning after December 15, 2016 and is to be applied on a retrospective or prospective basis. The standard is not expected to have a material impact.

In January 2016, the FASB issued ASU 2016-01, *“Financial Instruments – Overall: Recognition and Measurement of Financial Assets and Liabilities”*. This ASU addresses certain aspects of the guidance regarding recognition, measurement, presentation and disclosure of financial instruments, specifically the guidance for measuring the fair value of equity investments. This guidance is effective for annual and interim periods beginning after December 15, 2017, and is to be applied by means of a cumulative-effect adjustment to the Statement of Financial Position as of the beginning of the fiscal year of adoption, with amendments related to equity securities without readily determinable fair values to be applied prospectively. We do not expect the standard to have a material impact.

In February 2016, the FASB issued ASU 2016-02, *“Leases”*. This ASU addresses the recognition, measurement, presentation and disclosure in the financial statements of the assets and liabilities related to operating leases. This guidance is effective for annual and interim periods beginning after December 15, 2018. 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 costs incurred in conjunction with acquisitions and dispositions. 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 acquisition and disposition costs, including associated taxes, to be unrelated to our operating businesses. Operating cash flows provided by our jointly-controlled businesses in the form of operating loans are included in distributable cash. The investment community uses distributable cash to assess the source and sustainability of our dividends.

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

- distributions received/receivable from our jointly-controlled businesses and cash flows from our wholly-owned and majority-controlled 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 each 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 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 December 31		Year ended December 31, 2015	
	2015	2014	2015	2014
Cash from operating activities	76	71	287	215
Add (deduct):				
Project development costs ⁽¹⁾	29	20	85	79
Change in non-cash working capital and other	(3)	(13)	(19)	(2)
Principal repayments on senior notes	(3)	(3)	(12)	(12)
Maintenance capital expenditures	(2)	(1)	(4)	(6)
Distributions earned greater (less) than distributions received ⁽²⁾	3	(2)	(3)	(5)
Preferred Share dividends	(7)	(4)	(24)	(16)
Distributable cash	93	68	310	253

(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 months and year ended December 31, 2015 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.

Adjusted Net Income attributable to Common Shares – 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, gains or losses on sales of assets, certain fair value adjustments, and asset impairment losses. We believe our use of adjusted net income attributable to Common Shares 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 attributable to Common Shares to net income attributable to Common Shares.

(\$ Millions)	Three months ended December 31		Year ended December 31	
	2015	2014	2015	2014
Adjusted net income attributable to Common Shares	15	9	66	25
Extraordinary loss, net of tax ⁽¹⁾	–	–	(10)	–
Midstream – gain on sale of assets ⁽²⁾	–	–	37	–
Midstream – unrealized loss on revaluation of Veresen Midstream debt ⁽³⁾	(12)	–	(37)	–
Midstream – unrealized gain on Veresen Midstream cross currency swap ⁽⁴⁾	11	–	32	–
Midstream – write-down of deferred financing costs ⁽⁵⁾	–	–	(2)	–
Midstream – potential customer settlement ⁽⁶⁾	(16)	–	(32)	–
Power – loss from discontinued operations before tax ⁽⁷⁾	–	(16)	–	(16)
Power – unrealized gain (loss) on interest rate hedge ⁽⁸⁾	5	(4)	(1)	(12)
Power – one time York OPA settlement ⁽⁹⁾	–	–	–	4
Corporate – gain on sale of assets ⁽¹⁰⁾	–	–	–	14
Corporate – gain on forward foreign exchange contracts	–	34	–	39
Corporate – asset impairment loss ⁽¹¹⁾	–	(5)	–	(5)
Taxes ⁽¹²⁾	5	3	5	3
Effect of corporate tax rate changes ⁽¹³⁾	6	–	2	–
Net income attributable to Common Shares	14	21	60	52

Net income attributable to Common Shares includes the following items which are non-operating in nature and/or unusual items and which we do not expect to recur:

- (1) Loss due to the de-recognition of regulatory assets and liabilities related to Alliance.
- (2) Gain on the sale of the Hythe/Steeprock assets to Veresen Midstream on March 31, 2015.
- (3) Loss on the revaluation of US dollar-denominated Term Loan B held by Veresen Midstream.
- (4) Gain on the Veresen Midstream cross currency swap entered into to hedge the impact of changes in foreign exchange and interest rates on the Term Loan B held by Veresen Midstream.
- (5) Adjustment to deferred financing costs related to fees incurred on a modification to Veresen Midstream's debt.
- (6) Provision recognized in 2015 in respect of potential adjustments relating to Aux Sable customer obligations.
- (7) Results relating to U.S. gas-fired assets that were sold January 8, 2015.
- (8) Gain (loss) on revaluation of interest rate hedges held by York Energy Centre and Grand Valley Wind Farms.
- (9) Retroactive adjustment received in relation to York Energy Center's purchase agreement with the OPA.
- (10) Gains on the sale of the Culliton Creek run-of-river development project and our 50% interest in Alton Gas Storage.
- (11) Impairment of land we own in Ontario.
- (12) The related taxes on the adjusting items described above.
- (13) Impact of increased corporate income tax rate in the province of Alberta and a lower rate in the U.S. due to a U.S.-based organizational restructuring.

SELECTED QUARTERLY FINANCIAL INFORMATION

(\$ Millions, except where noted)	2015				2014			
	Q4	Q3	Q2	Q1	Q4	Q3 ⁽¹⁾	Q2 ⁽¹⁾	Q1 ⁽¹⁾
Operating revenues	40	38	37	72	68	68	79	87
Net income (loss) attributable to Common Shares	14	8	(12)	50	21	3	(3)	31
Net income (loss) per Common Share (\$)								
– basic and diluted	0.05	0.03	(0.04)	0.17	0.08	0.01	(0.01)	0.16
Distributable cash	93	71	65	81	68	55	64	66
Distributable cash per Common Share (\$)								
– basic and diluted	0.31	0.25	0.22	0.28	0.26	0.24	0.29	0.33
Cash from operating activities	76	77	101	33	71	50	49	45

(1) Comparative figures in this table have been reclassified. See Note 5 in our December 31, 2014 consolidated financial statements

Significant items that affected quarterly financial results include the following:

- Fourth quarter 2015 reflects a continuation of low fractionation margins at Aux Sable and higher Jordan Cove-related spending.
- Third quarter 2015 reflects lower earnings from Aux Sable driven by low fractionation margins.
- Second quarter 2015 reflected lower earnings from Aux Sable driven by low fractionation margins and the provision recognized relating to Aux Sable customer obligations.
- First quarter 2015 reflected a full quarter of Ruby distributions and higher Jordan Cove-related project development costs.
- Fourth quarter 2014 reflected new distributions received from Ruby, higher Jordan Cove-related project development costs and lower earnings from Aux Sable driven by weak commodity prices.
- Third quarter 2014 reflected lower earnings from Aux Sable and higher Jordan Cove related project development costs.
- Second quarter 2014 reflected lower earnings from Aux Sable and higher project development costs.
- First quarter 2014 reflected higher earnings from Aux Sable.

RELATED PARTY TRANSACTIONS

On March 30, 2012, we provided a \$47 million amortizing term loan to Grand Valley, a jointly-controlled business. Principal and interest are payable on a quarterly basis. The loan bears interest of 5.2% and the maturity date is December 31, 2031. At December 31, 2015, the outstanding balance was \$42 million (2014 – \$44 million).

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 December 31, 2015.

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 December 31, 2015, 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.

Effective July 1, 2015, we successfully implemented an Enterprise Resource Planning (“ERP”) system and made changes to certain related processes. As a result of the ERP system, certain processes supporting our internal control over financial reporting changed in 2015.

Other than the ERP system implementation there have been no changes made to internal controls over financial reporting during the period ended December 31, 2015 that have materially affected, or are reasonably likely to materially affect, internal controls over financial reporting. Although the ERP implementation changed certain specific activities within the accounting function, it did not significantly affect the overall controls and procedures we follow in establishing internal controls over financial reporting.

MANAGEMENT'S REPORT

To the Shareholders of Veresen Inc.

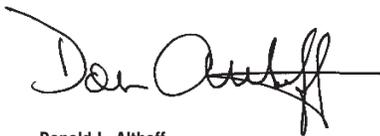
The consolidated financial statements of Veresen Inc. ("Veresen") and all information contained in this annual report are the responsibility of management. The consolidated financial statements have been prepared by management in accordance with accounting principles generally accepted in the United States of America (US GAAP). If alternative accounting methods exist, management has chosen those it deems most appropriate in the circumstances. Financial statements are not precise since they include certain amounts based on estimates and judgements. Actual results may differ from these estimates and judgements. Management has ensured that these consolidated financial statements are presented fairly in all material respects.

Management maintains internal accounting and administrative controls designed to provide reasonable assurance that the financial information contained in this annual report is, in all material respects, relevant, reliable and accurate, and that assets are appropriately accounted for and adequately safeguarded.

The Board of Directors is responsible for reviewing and approving Veresen's annual consolidated financial statements and, primarily through its Audit Committee, for ensuring that management fulfills its responsibilities for financial reporting and internal control.

The Audit Committee is comprised of four independent and financially literate board members that meet regularly during the year with management and the external auditors to satisfy itself that management's responsibilities are being discharged; to review and approve the interim consolidated financial statements, Management's Discussion and Analysis and other information contained in Veresen's interim reports prior to their release; and to review the annual consolidated financial statements, Management's Discussion and Analysis and other information contained in Veresen's Annual Report, as well as its Annual Information Form prior to submitting them to the Board of Directors for approval.

The independent external auditors, PricewaterhouseCoopers LLP, have been appointed by the shareholders of Veresen to express an opinion as to whether the consolidated financial statements of Veresen present fairly, in all material respects, its financial position as at December 31, 2015 and 2014 and its results of operations and cash flows for the years then ended in accordance with US GAAP.



Donald L. Althoff
President and Chief Executive Officer



Theresa Jang
Senior Vice President, Finance and Chief Financial Officer

March 9, 2016

INDEPENDENT AUDITOR'S REPORT

To the Shareholders of Veresen Inc.

We have audited the accompanying consolidated financial statements of Veresen Inc., which comprise the consolidated statements of financial position as at December 31, 2015 and December 31, 2014 and the consolidated statements of income, comprehensive income, shareholders' equity and cash flows for the years then ended, and the related notes, which comprise a summary of significant accounting policies and other explanatory information.

Management's responsibility for the consolidated financial statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with accounting principles generally accepted in the United States of America, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditor's responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of Veresen Inc. as at December 31, 2015 and December 31, 2014 and the results of its operations and its cash flows for the years then ended in accordance with accounting principles generally accepted in the United States of America.

PricewaterhouseCoopers LLP

Chartered Professional Accountants
Calgary, Alberta, Canada

March 9, 2016

CONSOLIDATED STATEMENT OF FINANCIAL POSITION

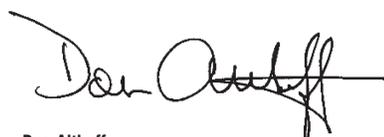
(Canadian \$ Millions; number of shares in Millions)

	December 31, 2015	December 31, 2014
Assets		
Current assets		
Cash and short-term investments	58	51
Restricted cash	7	5
Distributions receivable	52	46
Accounts receivable and other (note 8)	36	68
Assets held for sale (note 5)	–	39
	153	209
Investments in jointly-controlled businesses (note 7)	1,312	885
Investments held at cost (note 4)	1,981	1,660
Rate-regulated asset (note 19)	–	24
Pipeline, plant and other capital assets (note 9)	919	1,504
Intangible assets (note 10)	151	393
Due from jointly-controlled businesses (note 21)	42	44
Other assets	13	18
	4,571	4,737
Liabilities		
Current liabilities		
Accounts payable and other (note 11)	65	71
Deferred revenue	2	2
Dividends payable	25	8
Current portion of long-term senior debt (note 12)	13	11
Liabilities associated with assets held for sale (note 5)	–	4
	105	96
Long-term senior debt (note 12)	1,087	1,800
Deferred tax liabilities (note 14)	256	256
Other long-term liabilities (note 13)	36	53
	1,484	2,205
Shareholders' Equity		
Share capital (note 15)		
Preferred shares	536	342
Common shares (299 and 285 outstanding at December 31, 2015 and December 31, 2014, respectively)	3,354	3,186
Additional paid-in capital	4	4
Cumulative other comprehensive income (loss)	359	(65)
Accumulated deficit	(1,166)	(935)
	3,087	2,532
	4,571	4,737

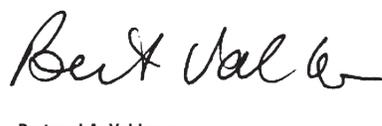
Commitments and Contingencies (note 16)

See accompanying Notes to the Consolidated Financial Statements

Approved by the Board of Directors of Veresen Inc.



Don Althoff
Director



Bertrand A. Valdman
Director

CONSOLIDATED STATEMENT OF INCOME

(Canadian \$ Millions, except per Common Share amounts (note 15))	Year ended December 31	
	2015	2014
Equity income (note 7)	77	146
Dividend income (note 4)	116	16
Operating revenues	187	302
Operations and maintenance	(76)	(141)
General and administrative	(38)	(49)
Project development	(85)	(79)
Depreciation and amortization	(60)	(83)
Interest and other finance	(53)	(59)
Foreign exchange and other (note 17)	8	41
Gain on sale of assets, net of impairment loss (note 5, 6 and 10)	37	9
Net income before tax	113	103
Current tax (note 14)	(37)	(30)
Deferred tax (note 14)	18	5
Net income from continuing operations	94	78
Discontinued operations (note 5)		
Net loss from discontinued operations before tax	-	(16)
Income tax on discontinued operations	-	6
Discontinued operations loss	-	(10)
Net income, before extraordinary loss	94	68
Extraordinary loss, net of tax (note 19)	(10)	-
Net income	84	68
Preferred Share dividends	(24)	(16)
Net income attributable to Common Shares	60	52
Net income per Common Share, basic and diluted		
Continuing operations	0.25	0.28
Discontinued operations	-	(0.04)
Extraordinary loss	(0.04)	-
	0.21	0.24

See accompanying Notes to the Consolidated Financial Statements

CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME

(Canadian \$ Millions)	Year ended December 31	
	2015	2014
Net income	84	68
Other comprehensive income		
Unrealized foreign exchange gain on translation	424	69
Other comprehensive income	424	69
Comprehensive income	508	137
Preferred Share dividends	(24)	(16)
Comprehensive income attributable to Common Shares	484	121

See accompanying Notes to the Consolidated Financial Statements

CONSOLIDATED STATEMENT OF CASH FLOWS

(Canadian \$ Millions)	Year ended December 31	
	2015	2014
Operating		
Net income	84	68
Net loss from discontinued operations	–	10
Equity income (note 7)	(77)	(146)
Distributions from jointly-controlled businesses	237	225
Depreciation and amortization	60	83
Foreign exchange and other non-cash items	6	9
Deferred tax	(18)	(5)
Gain on sale of assets, net of impairment loss (note 5, 6 and 10)	(37)	(9)
Extraordinary loss, net of tax (note 19)	10	–
Foreign exchange gain on investment activities	–	(39)
Changes in non-cash working capital (note 20)	22	7
Cash provided by continuing operations	287	203
Cash provided by discontinued operations (note 5)	–	12
	287	215
Investing		
Acquisitions, net of cash acquired	–	(1,635)
Foreign exchange gain on investment activities	–	39
Proceeds from sale of assets (note 5 and 6)	420	19
Investments in jointly-controlled businesses	(60)	(74)
Return of capital from jointly-controlled businesses	30	11
Pipeline, plant and other capital assets	(58)	(148)
Other	–	(2)
Cash provided (used) by continuing operations	332	(1,790)
Cash provided (used) by discontinued operations (note 5)	34	(4)
	366	(1,794)
Financing		
Long-term debt issued, net of issue costs	–	920
Long-term debt repaid	(738)	(262)
Net change in credit facilities, net of issue costs	25	(41)
Common Shares issued, net of issue costs	–	1,157
Preferred Shares issued, net of issue costs	194	–
Common Share dividends paid	(107)	(156)
Preferred Share dividends paid	(24)	(16)
Other	(8)	4
	(658)	1,606
Increase (decrease) in cash and short-term investments	(5)	27
Effect of foreign exchange rate changes on cash and short-term investments	12	(1)
Cash and short-term investments at the beginning of the year	51	25
Cash and short-term investments at the end of the year	58	51
Supplemental disclosure of cash flow information		
Interest paid	52	64
Taxes paid, net of refunds received	42	14

See accompanying Notes to the Consolidated Financial Statements

CONSOLIDATED STATEMENT OF SHAREHOLDERS' EQUITY

(Canadian \$ Millions)	Year ended December 31	
	2015	2014
Preferred Shares		
January 1	342	342
Series E Preferred Shares issued, net of issue costs (note 15)	194	–
Balance at the end of the year	536	342
Common Shares		
January 1	3,186	1,849
Convertible debentures converted into Common Shares, net of issue costs (note 15)	–	86
Common Shares issued under Premium Dividend and Dividend Reinvestment Plan (“DRIP”)	168	65
Common Shares issued, net of issue costs	–	1,170
December 31	3,354	3,170
Common Shares to be issued under DRIP ⁽¹⁾	–	16
Balance at the end of the year	3,354	3,186
Additional paid-in capital		
Balance at the beginning and end of the year	4	4
Cumulative other comprehensive income (loss)		
January 1	(65)	(134)
Other comprehensive income	424	69
Balance at the end of the year	359	(65)
Accumulated deficit		
January 1	(935)	(755)
Net income	84	68
Preferred Share dividends	(24)	(16)
Common Share dividends	(291)	(232)
Balance at the end of the year	(1,166)	(935)
Shareholders' Equity	3,087	2,532

(1) Common Shares to be issued under DRIP in respect of the December dividend declared are classified as dividends payable in 2015 (\$15 million).

See accompanying Notes to the Consolidated Financial Statements

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

Year ended December 31, 2015 and 2014 (Canadian \$ Millions, except where noted)

1. Description of Business

Veresen Inc. (“Veresen” or the “Company”) is a publicly-traded energy infrastructure company based in Calgary, Alberta, Canada.

Veresen operates in three business segments, Pipelines, Midstream, and Power. At December 31, 2015 the Company’s businesses were comprised of the following:

Entity ⁽¹⁾	Business Description	Ownership Interest (%)
CONTROLLED		
Pipeline Business		
Alberta Ethane Gathering System L.P. (“AEGS”)	AEGS owns a 1,330-kilometre pipeline system that transports purity ethane from various Alberta ethane extraction plants to Alberta’s major petrochemical complexes located near Joffre and Fort Saskatchewan, Alberta.	100
Midstream Business		
Burstall NGL Storage L.P. (“Burstall”)	Burstall owns a salt cavern ethane storage facility with a capacity of approximately 1 million barrels under construction near Burstall, Saskatchewan.	100
Power Business		
Gas-Fired Generation		
East Windsor Cogeneration L.P. (“East Windsor Cogeneration”)	An 86-MW cogeneration facility located in Windsor, Ontario.	100
London Cogeneration	A 17-MW cogeneration facility located in London, Ontario.	100
District Energy		
London District Energy	A district energy system that produces and distributes steam and chilled water fueled primarily by natural gas, located in London, Ontario	100
PEI District Energy	A district energy system that produces and distributes steam, hot water and electricity fueled primarily by biomass and waste fuel, located in Charlottetown, P.E.I.	100
Run-of-River Hydro		
Northbrook New York, LLC (“Northbrook”)	A 33-MW run-of-river hydroelectric power facility (“Glen Park”) located on the Black River near Watertown, New York.	100
Swift Power L.P. (“Swift”)	A 20-MW run-of-river hydroelectric power facility (“Dasque-Middle”) located near Terrace, B.C.	100
Furry Creek Power Ltd. (“Furry Creek”)	An 11-MW run-of-river power facility located 30 km north of Vancouver, B.C.	99
Clowhom Power L.P. (“Clowhom”)	Two 11-MW run-of-river power facilities located 65 km northwest of Vancouver, B.C.	100
Waste Heat		
EnPower Green Energy Generation Limited Partnership (“EnPower”)	Two 5-MW waste-heat power generation facilities located at Spectra pipeline’s 150 Mile House and Savona, B.C. compressor stations.	100
Wind Power		
St. Columban Energy L.P. (“St. Columban”)	A 33-MW wind power facility in the County of Huron, Ontario	90
INVESTMENTS HELD AT COST		
Pipeline Business		
Ruby Pipeline Holding Company L.L.C.	The Ruby Pipeline system is a 680-mile, 42-inch pipeline system that transports natural gas between the Opal hub in Wyoming and the Malin hub in Oregon.	50 ⁽²⁾ (note 4)

Entity ⁽¹⁾	Business Description	Ownership Interest (%)
JOINTLY-CONTROLLED		
Pipeline Business		
Alliance Pipeline Limited Partnership (“Alliance Canada”) Alliance Pipeline L.P. (“Alliance U.S.”) (Collectively “Alliance” or “Alliance Pipeline”)	Alliance owns a 3,000-kilometre natural gas pipeline comprised of a mainline and various connecting lateral pipelines. The Alliance pipeline extends from northeastern B.C. to points near Chicago, Illinois.	50
Midstream Business		
Aux Sable Canada L.P. Sable NGL Services L.P. (“Sable NGL Services”) (Collectively “Aux Sable Canada”)	<i>Aux Sable Canada owns:</i> NGL injection facilities on the Alliance pipeline in Alberta and B.C.; An off-gas processing facility in Fort Saskatchewan, Alberta; A natural gas processing plant in northeastern B.C.; and A natural gas pipeline to connect its gas processing plant to the Alliance pipeline.	50
Aux Sable Liquid Products L.P. (“ASLP”) Aux Sable Midstream LLC (“ASM”) Alliance Canada Marketing L.P. (“ACM”) (Collectively “Aux Sable U.S.”)	<i>Aux Sable U.S. owns:</i> A natural gas liquids (“NGL”) extraction and fractionation facility near the terminus of the Alliance pipeline; A natural gas processing plant in the Bakken region of North Dakota; A natural gas pipeline which connects the gas processing plant to the Alliance pipeline; Storage facilities, downstream NGL pipelines and loading facilities adjacent to the NGL extraction and fractionation facility; and Short-term and long-term natural gas transportation capacity on the Alliance pipeline.	42.7
Veresen Midstream LP (“Veresen Midstream”)	Comprised of natural gas processing, gathering, and compression assets, including the 200 mmcf/d Saturn compression station and the 200 mmcf/d Tower and 400 mmcf/d Sunrise gas plants under construction, located in the Cutbank Ridge region of Alberta and British Columbia. Adjacent to this infrastructure is the Hythe/Steepprock complex, comprised of two natural gas processing plants with combined functional capacity of 516 mmcf/d, as well as approximately 40,000 horsepower of compression and 370 km of gas gathering lines.	50 ⁽³⁾ (note 6)
Power Business		
Gas-Fired Generation		
York Energy Centre L.P. (“York Energy Centre”)	A 400-MW simple cycle gas turbine peaking generation facility in the York region, Ontario	50
Waste Heat		
NRGreen Power Limited Partnership (“NRGreen”)	Four 5-MW waste heat power generation facilities located at Alliance’s Saskatchewan compressor stations; and, A 13-MW waste heat power generation facility located at Alliance’s Windfall compressor station in Alberta.	50
Wind Power		
Grand Valley I and II Limited Partnership (“Grand Valley”)	Three wind power facilities, 9 MW, 11 MW and 40 MW, respectively, near Grand Valley, Ontario.	75

As at December 31, 2015 the Company's significant development projects consisted of the following:

Entity ⁽¹⁾	Business Description	Ownership Interest (%)
CONTROLLED		
Jordan Cove Energy Project L.P.)	The Jordan Cove LNG terminal is a development project that is proposed to export liquefied natural gas from Coos Bay, Oregon.	100
JOINTLY-CONTROLLED		
Pacific Connector Gas Pipeline L.P.	The Pacific Connector Gas Pipeline, a proposed 232-mile pipeline, is a development project that is proposed to connect the Jordan Cove LNG terminal to a natural gas hub at Malin, Oregon.	50

(1) Where applicable, defined entities include the respective managing general partner.

(2) Ownership percentage represents convertible preferred interest in Ruby Pipeline Holding Company, L.L.C., a parent of Ruby Pipeline L.L.C., holder of the Ruby pipeline system (note 4).

(3) On a fully-diluted basis, the Company's ownership interest as at December 31, 2015 was 48.5%. Prior to March 31, 2015 the Company owned 100% of the Hythe/Steeprock complex (note 6).

2. Basis of Presentation

These consolidated financial statements have been prepared by management in accordance with accounting principles generally accepted in the United States of America ("US GAAP").

Amounts are stated in millions of Canadian dollars unless otherwise indicated.

The preparation of financial statements in accordance with US GAAP requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues, expenses, financial instruments and taxes. Actual amounts could differ from these estimates. Significant estimates used in the preparation of these consolidated financial statements relate to the determination of any impairment in the carrying value of long-term assets, the estimated useful lives over which certain assets are depreciated or amortized, and the measurement of asset retirement obligations, and contingencies.

These consolidated financial statements include the accounts of the Company and its subsidiaries. The Company consolidates its interest in entities over which it is able to exercise control. To the extent there are interests owned by other parties, the other parties' interests are included in Non-Controlling Interest. Veresen accounts for its jointly-controlled businesses using the equity method, and its investment in Ruby Pipeline Holding Company LLC ("Ruby") using the cost method.

Reporting in Accordance with US GAAP

In February 2014 the Alberta Securities Commission ("ASC") and Ontario Securities Commission ("OSC") issued a relief order which permits the Company to continue to prepare its financial statements in accordance with US GAAP until the earliest of: (i) January 1, 2019; (ii) the first day of the financial year that commences after the Company ceases to have activities subject to rate regulation; or (iii) the effective date prescribed by the International Accounting Standards Board for the mandatory application of a standard within International Financial Reporting Standards specific to entities with activities subject to rate regulation. This ASC/OSC relief order effectively replaced and extended the previous relief order, which was due to expire effective January 1, 2015.

3. Summary of Significant Accounting Policies

New Accounting Pronouncements

The following new Accounting Standards Updates ("ASU") have been issued, as of December 31, 2015.

Effective January 1, 2015, the Company adopted 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 was applied prospectively and did not have a material impact to the Company.

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. In August 2015, the FASB issued ASU 2015-14, *“Revenue from Contracts with Customers – Deferral of the effective date”*. This ASU defers the effective date of Update 2014-09 for all entities by one year. This guidance is therefore effective for annual and interim periods beginning after December 15, 2017. The Company is currently evaluating the impact of the standard.

In June 2014, the FASB issued ASU 2014-10, *“Development Stage Entities: Elimination of Certain Financial Reporting Requirements, Including an Amendment to Variable Interest Entities Guidance in Topic 810, Consolidation”*. This ASU eliminates the concept of a development-stage entity from US GAAP along with the associated presentation and disclosure requirements for development-stage entities. The removal of the development stage entity reporting requirements is effective for annual reporting periods beginning after December 15, 2014 and does not have a material impact to the Company. The consolidation guidance was also amended to eliminate the development stage entity relief when applying the variable interest entity model and evaluating the sufficiency of equity at risk. The Company is currently evaluating the impact of the amendment to the consolidation guidance, which is effective for annual reporting periods beginning after December 15, 2015. The new standard requires these amendments be applied retrospectively.

In November 2014, the FASB issued ASU 2014-16, *“Derivatives and Hedging”*. This ASU provides guidance to clarify the criteria in evaluating the economic characteristics and risks of a host contract in a hybrid financial instrument that is issued in the form of a share. This guidance is effective for annual and interim periods beginning after December 15, 2015, and is to be applied prospectively. The Company is currently evaluating the impact of the standard.

In January 2015, the FASB issued ASU 2015-01, *“Income Statement – Extraordinary and Unusual Items”*. This ASU simplifies income statement classification by removing the concept of extraordinary items from US GAAP. This guidance is effective for annual and interim periods beginning after December 15, 2015, and may be applied prospectively or retrospectively. The Company is currently evaluating the impact of the standard.

In February 2015, the FASB issued ASU 2015-02, *“Consolidation: Amendments to the Consolidation Analysis”*. This ASU amends the current consolidation guidance, specifically the guidance in determining whether or not an entity is a variable interest entity. This guidance is effective for annual and interim periods beginning after December 15, 2015, and may be applied on a full or modified retrospective basis. The Company is currently evaluating the impact of the standard.

In April 2015, the FASB issued ASU 2015-03, *“Interest – Simplifying the Presentation of Debt Issuance Costs”*. This ASU changes the presentation of debt issue costs in financial statements. Under the ASU, an entity presents such costs in the balance sheet as a direct reduction from the related debt liability rather than as an asset. Amortization of the costs is reported as interest expense. This guidance is effective for annual and interim periods beginning after December 15, 2015, and is to be applied retrospectively. The Company is currently evaluating the impact of the standard.

In June 2015, the FASB issued ASU 2015-10, *“Technical Corrections and Improvements”*. This ASU represents changes to clarify the Codification, correct unintended application of guidance, or make minor improvements to the Codification that are not expected to have a significant effect on current accounting practice. This guidance is effective for annual and interim periods beginning after December 15, 2015. The Company is currently evaluating the impact of the standard.

In November 2015, the FASB issued ASU 2015-017, *“Income Taxes: Balance Sheet Classification of Deferred Taxes”*. This ASU changes the classification of deferred tax liabilities and assets. Under the ASU, an entity classifies deferred tax liabilities and assets as non-current in the statement of financial position. This guidance is effective for annual and interim periods beginning after December 15, 2016 and is to be applied on a retrospective or prospective basis. The Company does not expect the standard to have a material impact.

In January 2016, the FASB issued ASU 2016-01, “*Financial Instruments – Overall: Recognition and Measurement of Financial Assets and Liabilities*”. This ASU addresses certain aspects of the guidance regarding recognition, measurement, presentation and disclosure of financial instruments, specifically the guidance for measuring the fair value of equity investments. This guidance is effective for annual and interim periods beginning after December 15, 2017, and is to be applied by means of a cumulative-effect adjustment to the Statement of Financial Position as of the beginning of the fiscal year of adoption, with amendments related to equity securities without readily determinable fair values to be applied prospectively. The Company does not expect the standard to have a material impact.

In February 2016, the FASB issued ASU 2016-02, “*Leases*”. This ASU addresses the recognition, measurement, presentation and disclosure in the financial statements of the assets and liabilities related to operating leases. This guidance is effective for annual and interim periods beginning after December 15, 2018. The Company is currently evaluating the impact of the standard.

Cash and Short-Term Investments

Cash and short-term investments comprise cash and highly liquid investments with original maturities of 90 days or less and carrying values which approximate market value. A portion of these short-term investments are held in trust accounts, the majority of which are permitted to be used for operating, capital expenditure and working capital purposes.

Investments in Jointly-Controlled Businesses

Investments over which the Company exercises significant influence, but does not have controlling financial interests, are accounted for using the equity method. Equity investments are initially measured at cost and are adjusted for the Company's proportionate share of undistributed equity earnings or loss. Equity investments are increased for contributions made to and decreased for distributions received from the investees.

Pipeline, Plant and Other Capital Assets

Fixed asset category	Measurement	Depreciation policy and rates (per annum)
Pipeline	Cost	Straight-line basis with a rate of 4%
Plant	Cost	Straight-line basis over the life of the asset with rates ranging from 3% to 33%
Power facilities	Cost	Straight-line basis over the life of the asset with rates ranging from 3% to 33%
Administrative	Cost	Straight-line basis over the life of the asset or the term of the lease, where applicable, with rates ranging from 20% to 33%
Capital spares	Lower of average cost or net realizable value	Not depreciated
Land	Cost	Not depreciated

Expenditures that increase or prolong the service life or capacity of an asset are capitalized. Maintenance and repair costs are expensed as incurred. Construction work in progress, which includes capitalized interest, will be reclassified to pipeline, plant and power facilities and depreciated over the estimated useful life upon commencement of operations.

Intangible Assets

Intangible assets predominantly consist of an acquired customer relationship and service agreement, ethane transportation agreements (“ETAs”), power purchase agreements, computer software and water licenses. Intangible assets are amortized on a straight-line basis over their respective useful lives ranging from 11 to 40 years.

Impairment of Long-Lived Assets Investments in Jointly-Controlled Businesses and Investments Held at Cost

The Company evaluates, at least annually, the long-lived assets such as pipeline, plant and other capital assets and intangible assets, the investments in jointly-controlled businesses and investments held at cost for impairment when events or changes in circumstances indicate, in management’s judgment, that the carrying value of such assets may not be recoverable.

When such a determination is made for long-lived assets, management’s estimate of the sum of undiscounted future cash flows attributable to the assets is compared to the carrying value of the assets to determine whether the recoverability of the carrying value has been impaired. If the carrying value exceeds the sum of undiscounted cash flows, the carrying value of the assets is deemed to be impaired. The amount by which the carrying value exceeds the estimated fair value is recognized as an impairment loss.

When such a determination is made for investments in jointly-controlled businesses and investments held at cost, management's estimate of the sum of discounted cash flows attributable to the investments is compared to the carrying value of the investments. If the carrying value exceeds the sum of discounted cash flows, the carrying value of the investments is deemed to be impaired. The amount by which the carrying value exceeds the estimated fair value is recognized as an impairment loss.

Judgments and assumptions are inherent in management's estimate of both the undiscounted and discounted future cash flows used to determine recoverability of an asset and the estimate of an asset's fair value used to calculate the amount of any impairment.

Asset Retirement Obligations

The estimated fair value of asset retirement obligations associated with tangible long-lived assets are recognized in the period in which they are incurred if a reasonable estimate of a fair value can be determined. 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 the assets.

For some of the Company's assets, including those held by the Company's jointly-controlled businesses, it is not possible to make a reasonable estimate of ARO due to the indeterminate timing and scope of the asset retirements.

Revenue Recognition

Power revenue derived from the sale of energy in the form of electricity, steam, hot water and chilled water, is recognized on the accrual basis upon delivery at rates pursuant to the relevant agreements. In addition, the Company's gas-fired generation power facilities receive fixed capacity payments that are not dependent upon the amount of energy delivered to customers. This revenue is recognized as earned on a monthly basis.

AECS transportation revenue is based on toll charges and operating cost recoveries, including maintenance capital, as provided for under the ETAs. Revenue is recognized at each receipt point and is subject to minimum take-or-pay arrangements.

Hythe/Steepprock revenue is based on providing minimum volume capacity over an agreed upon period, and is recognized at the later of when committed volume capacity was provided under the agreement or when the counterparty's ability to apply deficiency volume credit had expired. Subsequent to the March 31, 2015 sale of Hythe/Steepprock to Veresen Midstream (note 6), Hythe/Steepprock revenues are recognized through the Company's equity income from Veresen Midstream.

Rate-Regulated Accounting

The Company has rate-regulated businesses, including Alliance which uses rate-regulated accounting for certain expenditures as approved by the National Energy Board ("NEB").

Project Development Costs

The Company expenses project development costs as incurred. Project development costs are only capitalized when, in management's judgment, certain commercial and regulatory criteria have been met, which make it probable that such costs will be recoverable from a project's future revenues. Capitalized project development costs are amortized on a systematic basis over the applicable project's useful life.

Capitalized Interest

The Company capitalizes interest costs which are directly attributable to the acquisition or construction of qualifying assets.

Foreign Currency Translation

The functional currency of the Company and its Canadian subsidiaries is the Canadian dollar. The Company's foreign operations are self-sustaining and are translated using the current rate method. Under this method all assets and liabilities are translated into Canadian dollars using the exchange rate in effect at the balance sheet date, and all revenues and expenses are translated into Canadian dollars at average exchange rates during the year. The resulting net cumulative translation gain or loss is deferred and reported as a separate component of other comprehensive income. A portion of such deferred translation gain or loss is recognized in net income when such a foreign subsidiary is disposed of or liquidated.

Long-term Incentive Compensation

The Company has a long-term employee incentive plan (“LTIP”) and a deferred share unit plan (“DSU”). Under each plan, notional common shares are granted to eligible employees. The notional shares are payable in cash at the date of vesting when certain conditions are met, including the employee’s continued employment during a specified period. Amounts payable under the LTIP are further dependent upon the achievement of specified performance targets. Expenses related to the various LTIPs and DSU plan are accounted for on an accrual basis.

Financial Instruments

Financial assets and financial liabilities are classified as held-for-trading, available-for-sale or at amortized cost. Financial instruments are initially recorded at fair value on the balance sheet. Subsequent measurement of each financial instrument is based on its classification. At December 31, 2015 and 2014, the Company did not have held-to-maturity instruments or instruments in qualifying hedging relationships.

Financial assets and liabilities classified as held-for-trading are measured at fair value with changes in fair value recognized in earnings.

Available-for-sale financial assets are measured at fair value with changes in fair value recognized in other comprehensive income.

The investment in Ruby is recorded at cost.

Income Tax

The Company uses the liability method of accounting for income taxes. Under this method, current income taxes are recognized for the estimated income taxes payable in respect of the current year, which includes an accrual for interest and penalties, if any. Deferred tax assets and liabilities are recognized for temporary differences between the tax and accounting asset and liability bases using enacted tax rates and laws expected to apply when the liabilities are settled and the assets realized. Deferred tax assets are recognized in circumstances where it is considered more likely than not the related income tax benefits will be realized.

When appropriate, the Company records a valuation allowance against deferred tax assets to reflect that these tax assets may not be realized. In determining whether a valuation allowance is appropriate, the Company considers whether it is more likely than not that all or some portion of its deferred tax assets will not be realized, based on management’s judgments using available evidence about future events.

At times, the Company may claim tax benefits that may be challenged by a tax authority. The Company recognizes tax benefits only for tax positions that are more likely than not to be sustained upon examination by tax authorities. The amount recognized is measured as the largest amount of benefit that has a greater than 50% likelihood to be realized upon settlement. A liability for “unrecognized tax benefits” is recorded for any tax benefits claimed in the Company’s tax returns that do not meet these recognition and measurement standards.

Share Issuance Costs

Costs directly attributable to the raising of equity are charged against the related share capital.

4. Acquisitions

Acquisition of a 50% Interest in Ruby Pipeline

On November 6, 2014, the Company acquired, through a wholly-owned subsidiary, two entities which hold an aggregate 50% convertible preferred interest in Ruby Pipeline Holding Company, LLC, which owns the Ruby pipeline system (“Ruby”), for cash consideration of US\$1.425 billion. The acquisition was funded with proceeds from the October 1, 2014 subscription receipt offering and from a new unsecured non-revolving term loan (“Acquisition Credit Facility”).

Ruby is a 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 billion cubic feet per day (“bcf/d”). Ruby originates at the Opal natural gas hub in Wyoming and extends to the Malin natural gas hub in Oregon.

The acquisition is accounted for as an investment using the cost method. Transaction costs of approximately \$7 million have been classified with the investment in Ruby on the consolidated statement of financial position in accordance with the cost method of accounting.

The purchase price has been allocated as follows:

Consideration	
Cash consideration paid	1,628
Allocation of Consideration	
Investment in convertible preferred units in Ruby Pipeline Holding Company, LLC	1,628
Transaction costs	7
Investment in Ruby Pipeline	1,635

The Company recorded dividend income related to the acquired business of \$16 million for the period November 6, 2014 to December 31, 2014 and \$116 million for the year ended December 31, 2015.

5. Disposals

Assets Held for Sale

On January 8, 2015, the Company closed the transaction with an unrelated third party to dispose of its power facilities located in California and Colorado in the United States for proceeds of approximately US\$27 million (\$34 million) plus working capital. As a result, the assets and liabilities of the facilities were classified as held for sale on the consolidated statement of financial position as at December 31, 2014 and the results of operations have been presented as discontinued operations on the consolidated statement of earnings, with comparatives.

The table below details the assets and liabilities held for sale as at December 31, 2014:

Assets	
Cash	3
Receivables	3
Other	2
Property, plant and equipment	24
Intangible assets	7
Assets held for sale	39
Liabilities	
Payables	1
Accrued payables	3
Liabilities associated with assets held for sale	4

The table below provides details on the results of the discontinued operations:

	2015	2014
Operating revenues	–	36
Operations and maintenance	–	(24)
General and administrative	–	(1)
Depreciation and amortization	–	(15)
Interest and other finance	–	–
Asset impairment loss	–	(12)
Net loss from discontinued operations before tax	–	(16)
Income tax from discontinued operations	–	6
Discontinued operations loss	–	(10)

Gain on Sale of Assets

During the year ended December 30, 2014, the Company sold its Culliton Creek run-of-river development project and its 50% interest in Alton Gas Storage for a combined total of \$19 million, generating a combined pre-tax gain of \$14 million.

6. Veresen Midstream Transaction

On December 22, 2014, a new entity, Veresen Midstream, was formed, which is jointly controlled by the Company and affiliates of Kohlberg Kravis Roberts & Co L.P. (“KKR”), a global investment firm. On March 31, 2015, the Company funded its interest in Veresen Midstream by contributing its Hythe/Steeprock gathering and processing assets valued at \$920 million, and in exchange received from Veresen Midstream \$420 million in cash, resulting in a 50% equity position valued at \$500 million. As at March 31, 2015, the net book value of the Hythe/Steeprock assets contributed was \$838 million, resulting in a pre-tax gain on sale to the Company of \$37 million attributable to the monetary portion of the transaction. KKR funded its 50% interest in Veresen Midstream by contributing \$500 million in cash.

The table below details the net book value of assets and liabilities contributed to Veresen Midstream:

Capital assets	618
Customer relationship and service agreement intangibles	238
Asset retirement obligation	(16)
Deferred revenue	(1)
Other	(1)
	838

All of the Company's and half of KKR's Veresen Midstream equity are held in partnership units that are eligible to receive cash distributions. The remaining half of KKR's initial equity investment is in the form of payment-in-kind (“PIK”) units which do not receive cash distributions and instead accrete at a rate equal to the cash yield on the remaining equity plus 4% per year. The PIK units are convertible to cash-paying units after four years at either KKR's or the Company's option. Such conversion of the PIK units will cause dilution in the Company's ownership interest in Veresen Midstream. During the year ended December 31, 2015, as a result of cash distributions paid by Veresen Midstream, the Company's ownership decreased from 50% to 48.5%. The Company and KKR will have equal governance rights in Veresen Midstream so long as either partner's equity interest remains above 35%.

7. Investments in Jointly-Controlled Businesses

Condensed financial information (100%) for the Company's jointly-controlled businesses:

100%	As at December 31, 2015					Year ended December 31, 2015			As at December 31, 2015	Year ended December 31, 2015	
	Current Assets	Non-Current Assets	Current Liabilities ⁽¹⁾	Non-Current Liabilities ⁽¹⁾	Senior Debt	Revenues	Expenses	Profit (Loss) before Tax	Ownership (%)	Equity Investment	Equity Income (Loss)
Alliance Canada ⁽²⁾	132	1,177	33	24	954	473	344	129	50	178	56
Alliance U.S. ⁽³⁾⁽⁷⁾	73	1,247	53	19	600	441	268	173	50	271	75
Aux Sable Canada	42	107	55	8	–	436	447	(11)	50	44	(5)
ASLP ⁽⁴⁾⁽⁷⁾	48	620	168	6	–	76	155	(79)	43	171	(31)
ASM ⁽⁷⁾	26	315	22	1	–	238	235	3	43	136	1
ACM	5	–	3	–	–	120	142	(22)	43	1	(7)
York Energy Centre ⁽⁵⁾	15	265	10	44	247	65	48	17	50	27	6
Grand Valley	22	179	16	4	149	10	10	–	75	24	–
Veresen Midstream ⁽⁶⁾	77	2,145	57	20	1,215	169	172	(3)	49	410	(1)
Other ⁽⁷⁾	9	133	2	6	33	12	46	(34)	50	50	(17)
										1,312	77

100%	As at December 31, 2014					Year ended December 31, 2014		As at December 31, 2014	Year ended December 31, 2014		
	Current Assets	Non- Current Assets	Current Liabilities ⁽¹⁾	Non- Current Liabilities ⁽¹⁾	Senior Debt	Revenues	Expenses	Profit (Loss) before Tax	Ownership (%)	Equity Investment	Equity Income (Loss)
Alliance Canada ⁽²⁾	148	1,284	77	11	1,037	486	368	118	50	187	52
Alliance U.S. ⁽³⁾⁽⁷⁾	105	1,158	86	19	602	376	246	130	50	243	60
Aux Sable Canada	58	108	52	9	–	734	715	19	50	51	10
ASLP ⁽⁴⁾⁽⁷⁾	41	478	45	10	21	189	150	39	43	151	18
ASM ⁽⁷⁾	29	259	19	1	–	490	455	35	43	112	15
ACM	12	–	10	–	–	253	254	(1)	43	1	2
York Energy Centre ⁽⁵⁾	19	275	7	45	287	73	78	(5)	50	33	(5)
Grand Valley	5	50	2	44	–	8	6	2	75	27	1
Veresen Midstream ⁽⁶⁾	–	50	–	–	–	–	–	–	50	25	–
Other ⁽⁷⁾	24	162	41	6	1	12	26	(14)	50	55	(7)
										885	146

Upon acquisition of investments accounted for under the equity method, the Company prepared purchase price allocations of the purchase price to the assets and liabilities of the underlying investee and adjusts equity method earnings for the amortization of purchase price adjustments allocated to depreciable assets.

(1) Current liabilities and non-current liabilities exclude senior debt.

(2) At December 31, 2015, the Company had a \$48 million (December 31, 2014 – \$54 million) increase in the carrying value of Alliance Canada compared to the underlying equity in the net assets primarily resulting from the purchase price discrepancy as part of the acquisitions in 1997, 2002, and 2003 resulting in 50% ownership.

(3) At December 31, 2015, the Company had a US\$14 million (December 31, 2014 – US\$ 12 million) decrease in the carrying value of Alliance U.S. compared to the underlying equity in the net assets primarily resulting from the purchase price discrepancy as part of the acquisitions in 1997, 2002, and 2003 resulting in 50% ownership.

(4) At December 31, 2015, the Company had a US\$28 million (December 31, 2014 – US\$ 29 million) decrease in the carrying value of ASLP compared to the underlying equity in the net assets primarily resulting from the purchase price discrepancy as part of the acquisitions in 1997, 2002, and 2003 resulting in 42.7% ownership. During the year ended December 31, 2015 a \$32 million provision was recognized in respect of potential adjustments relating to customer obligations and a US\$3 million provision was recognized related to an alleged violation of the United States Environmental Protection Agency's ("EPA") Clean Air Act.

(5) At December 31, 2015, the Company had a \$41 million (December 31, 2014 – \$43 million) increase in the carrying value of York Energy Centre compared to the underlying equity in the net assets primarily resulting from the purchase price discrepancy as part of the acquisition in 2010 resulting in 50% ownership. Expenses include unrealized gains or losses on the interest rate hedge (note 17).

(6) At December 31, 2015, the Company had a \$42 million (December 31, 2014 – \$Nil) decrease in the carrying value of Veresen Midstream compared to the underlying equity in the net assets primarily resulting from the unrecognized gain on sale relating to the non-monetary portion of the Veresen Midstream transaction, which, on the date of acquisition, March 31, 2015, resulted in 50% ownership.

(7) Assets and liabilities of these investments have been translated into Canadian dollars using the exchange rate in effect at the balance sheet date and revenues and expenses have been translated into Canadian dollars at average exchange rates during the period.

Variable Interest Entity

On March 31, 2015, Veresen Midstream entered into natural gas gathering and compression agreements with Encana Corporation ("Encana") and Cutbank Ridge Partnership ("CRP"), under an initial term of 30 years with two five-year renewal terms at Encana and CRP's option. In addition, Veresen Midstream also assumed certain natural gas gathering and processing agreements that provide services to Encana with remaining terms of 17 years and up to a maximum of 13 one-year renewal terms.

The Company has determined it holds a variable interest in Veresen Midstream, but is not the primary beneficiary as the Company does not have the power to direct the key activities that most significantly impact Veresen Midstream's economic performance. This variable interest entity ("VIE") remains unconsolidated as the power to direct the activities of the partnership is shared between the Company and KKR. The Company is using the equity method to account for this investment. Key activities relate to the construction, operation, maintenance and marketing of assets owned by Veresen Midstream. The variable interests arise from certain terms under the long-term service agreements. The Company is not required to provide any financial support or guarantees to Veresen Midstream.

8. Accounts receivable and other

	2015	2014
Receivables	11	39
Accrued receivables	12	16
Prepaid expenses and other	1	8
Inventory	4	5
Due from jointly-controlled businesses	8	2
Reclassified to assets held for sale (note 5)	–	(2)
	36	68

9. Pipeline, Plant, and Other Capital Assets

	2015			2014		
	Cost	Accumulated depreciation	Net book value	Cost	Accumulated depreciation	Net book value
Pipeline	318	(137)	181	470	(134)	336
Plant	–	–	–	516	(59)	457
Power facilities	775	(106)	669	626	(172)	454
Administrative	5	(4)	1	10	(6)	4
Capital spares	–	–	–	1	–	1
Land	52	–	52	42	–	42
Construction work in progress	16	–	16	234	–	234
Reclassified to assets held for sale (note 5)	–	–	–	(114)	90	(24)
	1,166	(247)	919	1,785	(281)	1,504

There were no pipeline, plant and other capital assets deemed to be under operating leases at December 31, 2015 (2014 – cost: \$106 million, accumulated depreciation: \$82 million) which includes assets held for sale. There were no operating lease revenues generated by such assets for the year ended December 31, 2015 (2014 – \$36 million).

Asset Impairment Loss

In 2014, the Company recognized a \$5 million impairment loss on land held in Ontario, Canada. This resulted from the Company engaging an unrelated third party to complete a market valuation assessment of the land.

10. Intangible Assets

	2015			2014		
	Cost	Accumulated depreciation	Net book value	Cost	Accumulated depreciation	Net book value
Midstream customer relationship and service agreement (note 6)	–	–	–	283	(41)	242
Power agreements and licenses	180	(38)	142	268	(115)	153
Ethane transportation agreements (“ETAs”)	16	(12)	4	16	(11)	5
Computer software	7	(2)	5	–	–	–
Reclassified to assets held for sale (note 5)	–	–	–	(93)	86	(7)
	203	(52)	151	474	(81)	393

Power purchase agreements and water licenses represent the value attributed to intangible assets upon various acquisitions related to the Company’s power business. Each of the Company’s gas-fired generation facilities hold long-term power purchase agreements, which provide for capacity payments and the sale of electricity to their respective markets or customers, as applicable. Northbrook holds a long-term Federal Energy Regulatory Commission (“FERC”) license under which it operates and maintains the Glen Park facility. Swift holds a long-term electricity purchase agreement, awarded by BC Hydro, which provides for the sale of power produced from the Dasque-Middle run-of-river facility. The Furry Creek and Clowhom run-of-river facilities each hold 40-year water licenses attached to the land for the use of water at their respective sites.

ETAs represent value attributed to AEGS' intangible assets upon Veresen's acquisition in December 2004. Under the ETAs, which expire on December 31, 2018, shippers are committed to pay a minimum firm toll based on 90% of total committed volume, and to reimburse AEGS for all operating costs, including maintenance capital.

The intangible assets are amortized on a straight-line basis. For the year ended December 31, 2015, total amortization expense for intangible assets was \$12 million (2014 – \$28 million). Annual amortization expense for each of the next 5 years is expected to be approximately \$13 million.

11. Accounts payable and other

	2015	2014
Payables	9	31
Interest payable	6	6
Accrued payables	50	34
	65	71

12. Long-term Debt

	2015	2014
Veresen		
Revolving credit facility	148	122
3.95% Medium term notes due 2017	300	300
4.0% Medium term notes due 2018	150	150
3.06% Medium term notes due 2019	200	200
5.05% Medium term notes due 2022	50	50
Acquisition credit facility due 2016	–	726
	848	1,548
Less: current portion	–	–
	848	1,548
AEGS		
5.565% Senior notes due 2020	81	84
Less: current portion	(4)	(3)
	77	81
East Windsor Cogeneration		
6.283% Senior bonds due 2029	143	149
Less: current portion	(7)	(6)
	136	143
Furry Creek		
7.2947% Term loan due 2024	9	10
Less: current portion	(1)	(1)
	8	9
EnPower		
6.65% Term loan due 2018	19	20
Less: current portion	(1)	(1)
	18	19
	1,087	1,800

Veresen

Revolving Credit Facilities

On July 31, 2015, the Revolving Credit Facility was increased from \$550 million to \$750 million and the term extended by one year to mature on May 31, 2019. Outstanding advances bear interest based on various quoted floating rates plus a margin. At December 31, 2015, the Facility was drawn by \$148 million (December 31, 2014 – \$122 million).

Veresen Acquisition Credit Facility

The Acquisition Credit Facility was a new unsecured non-revolving term loan used to fund the Ruby acquisition in 2014. The Acquisition Credit Facility was repaid in full in 2015.

Compliance with Debt Covenants

Each of Veresen and its businesses were in compliance with their respective debt covenants as at December 31, 2015, and 2014.

Scheduled Principal Repayments of Long-Term Senior Debt

Scheduled principal repayments of long-term senior debt, including the current portion thereof, are as follows:

	For the years ending December 31
2016	13
2017	460
2018	180
2019	214
2020	74
Thereafter	159
	1,100

13. Other Long-Term Liabilities

	2015	2014
Asset retirement obligations	27	39
Other	10	16
	37	55
Less: current portion	(1)	(2)
	36	53

Asset Retirement Obligations

At December 31, 2015, \$24 million of the consolidated asset retirement obligation (“ARO”) relates to AEGS (2014 – \$23 million). This represents management’s estimate of the cost to abandon the ethane transportation pipeline and the timing of the costs to be incurred. Estimated cash flows were discounted at AEGS’ weighted average credit-adjusted risk free rate of return of 6.3% (2014 – 6.3%) and an inflation rate of 2.3% (2014 – 2.3%). The total undiscounted amount of future cash flows required to settle the obligation is estimated to be \$111 million (2014- \$111 million). The estimated ARO costs reflect such activities as dismantling, demolition and disposal of a portion of the pipeline as well as remediation and restoration of the surface land. Payments to settle the obligation are not expected to occur prior to 2040.

On March 31, 2015, the Company funded its interest in Veresen Midstream by contributing its Hythe/Steepprock gathering and processing assets, including its asset retirement obligation (note 6).

	2015	2014
Asset retirement obligations, January 1	39	37
Sale of obligation to Veresen Midstream	(14)	–
Accretion expense	2	2
Asset retirement obligations, December 31	27	39

Other

Other long-term liabilities primarily represent \$8 million of accruals for LTIP and DSU (2014 – \$14 million). Payments made under the LTIP and DSU in 2015 were \$3 million (2014 – \$5 million).

14. Taxes

Components of Taxes

The following is a summary of the significant components of the Company's tax expense:

	2015	2014
Current tax expense	37	30
Deferred tax expense (recovery)		
Origination and reversal of temporary differences	(28)	(7)
Benefit of loss carry-forwards	8	(2)
Change in valuation allowance	2	4
Total deferred tax expense	(18)	(5)
Total tax expense	19	25

Geographical Components

Net income before tax and discontinued operations for the years ended 2015 and 2014 are as follows:

	2015	2014
Net income before tax and discontinued operations		
Canada	60	91
United States	53	12
Net income before tax and discontinued operations	113	103

Tax expense for the years ended 2015 and 2014 are as follows:

	2015	2014
Current tax expense		
Canada	3	10
United States	34	20
Total current tax expense	37	30
Deferred tax expense (recovery)		
Canada	20	20
United States	(38)	(25)
Total deferred tax expense (recovery)	(18)	(5)
Total tax expense	19	25

Components of Deferred Taxes

The provision for deferred taxes arises from temporary differences in the carrying values of assets and liabilities for financial statement and income tax purposes and the effect of loss carryforwards. The items comprising the deferred tax assets and liabilities are as follows:

	2015	2014
Deferred tax liabilities (assets)		
Investments in jointly-controlled businesses	360	263
Regulatory assets (note 19)	–	24
Pipeline, plant and other capital assets	14	82
Non-capital losses	(94)	(86)
Asset retirement obligations	(7)	(10)
Deferred revenue and costs	(17)	(17)
Total net deferred tax liabilities	256	256

The above deferred tax balances at December 31, 2015 and 2014 are net of valuation allowances of \$12 million and \$9 million, respectively.

Tax Reconciliation

The provision for taxes differs from the result that would be obtained by applying the combined Canadian federal and provincial statutory income tax rate to net income before tax and non-controlling interest. The difference results from a number of factors summarized in the following reconciliation:

	2015	2014
Net income before tax and discontinued operations	113	103
Canadian statutory income tax rate	26.0%	25.0%
Income tax at statutory rate	29	26
Increase (decrease) resulting from:		
Deferred taxes related to Canadian regulated operations	3	8
Higher income tax rates in other jurisdictions	–	3
Deductible intercompany interest expense	(13)	(7)
Change in valuation allowance	2	4
Change in tax rates	(2)	–
Adjustment in respect of prior periods	(3)	(3)
Taxable capital gains greater (less) than accounting gains	2	(6)
Other	1	–
Tax expense	19	25
Net income before discontinued operations	94	78
Effective tax rate	16.8%	24.3%

The Company has Canadian and U.S. non-capital losses of \$104 million (2014 – \$287 million) and \$168 million (2014 – \$32 million), respectively. Canadian losses expire beginning in 2025. U.S. losses will expire in varying amounts from 2027 to 2033.

The Company has no unrecognized tax benefits as the recognition and measurement criterion has been met. It is more likely than not that the Company will realize its tax positions.

The Company is subject to Canadian federal and provincial income tax, U.S. federal and state income tax, and other foreign federal taxes. All Canadian federal and provincial income tax returns are subject to examination by the taxation authorities. All U.S. federal income tax returns and generally all U.S. state income tax returns for 2011 and subsequent years continue to remain subject to examination by the taxation authorities, in addition to years relating to non-operating losses are subject to examination.

15. Share Capital

Authorized

The authorized capital of the Company consists of (i) an unlimited number of Common Shares and (ii) Preferred Shares, issuable in series, to be limited in number to an amount equal to not more than one-half of the Common Shares issued and outstanding at the time of issuance of such Preferred Shares.

Common Shares

Common Shares	2015		2014	
	Number	Value	Number	Value
January 1 Opening balance⁽¹⁾	286,052,797	3,186	201,736,655	1,849
Convertible Debentures converted into Common Shares, net of issue costs	–	–	5,887,565	86
Common Shares issued under Premium Dividend and Dividend Reinvestment Plan (“DRIP”) ⁽²⁾	12,927,192	168	4,034,816	65
Common Shares issued, net of issue costs	–	–	73,370,000	1,170
December 31	298,979,989	3,354	285,029,036	3,170
Common Shares to be issued under DRIP ⁽²⁾⁽³⁾	–	–	1,023,761	16
	298,979,989	3,354	286,052,797	3,186

(1) Includes 1,023,761 Common Shares valued at \$16 million (2014 – 260,411 Common Shares; \$4 million) subsequently issued under DRIP.

(2) Represents Common Shares issued to satisfy a portion of the Company’s dividends.

(3) Common shares to be issued under DRIP in respect of the December dividend declared are classified as dividends payable in 2015

The weighted average number of Common Shares outstanding used to determine net income per Common Share on a basic and diluted basis for the year ended December 31, 2015 was 291,081,484 (2014 – 225,724,157).

Dividends

For the year ended December 31, 2015, the Company declared and paid dividends to common shareholders in the amount of \$291 million or \$1.00 per Common Share (2014 – \$227 million or \$1.00 per Common Share).

Premium Dividend and Dividend Reinvestment Plan

The Company’s Premium Dividend and Dividend Reinvestment Plan (“DRIP”) allows eligible shareholders to elect to reinvest the eligible portion of the dividend declared by the Company in additional Common Shares at a 5% discount to the average market price or to receive the dividend in cash plus a 2% premium cash payment based on the eligible portion of the dividend. The Company reserves the right to determine, for each dividend declared, how much new equity would be issued under the DRIP.

Preferred Shares

On April 1, 2015, the Company issued 8 million Cumulative Redeemable Preferred Shares, Series E (“Series E Preferred Shares”) at a price of \$25 per Series E Preferred Share, generating \$194 million of cash proceeds net of \$6 million of issue costs. The holders of Series E Preferred Shares are entitled to receive fixed cumulative preferential cash dividends at an annual rate of 5.00%, payable quarterly for an initial period up to but excluding June 30, 2020, if and when declared by the Board of Directors. The dividend rate will reset on June 30, 2020 and every five years thereafter at a rate equal to the sum of the then five-year Government of Canada bond yield plus 4.27%. The Series E Preferred Shares are redeemable by the Company, at the Company’s option, on June 30, 2020 and on June 30 of every fifth year thereafter.

Holders of Series E Preferred Shares have the right to convert all or any part of their shares into Cumulative Redeemable Preferred Shares, Series F (“Series F Preferred Shares”) subject to certain conditions, on June 30, 2020 and on June 30 of every fifth year thereafter. The holders of Series F Preferred Shares are entitled to receive quarterly floating rate cumulative dividends at a rate equal to the sum of the then 90-day Government of Canada treasury bill rate plus 4.27%.

16. Commitments and Contingencies

Veresen has operating leases for office premises and vehicles. Included in general and administrative expense are lease expenses of \$4 million (2014 – \$4 million). Expected future minimum lease payments under the operating leases are as follows:

For the years ending December 31	Operating leases
2016	6
2017	5
2018	5
2019	5
2020	5
Thereafter	24
Total minimum lease payments(1)	50

(1) Total rental payments to be received in future periods under non-cancelable subleases are \$1 million.

The Court of Appeal for Ontario denied Veresen's appeal of a portion of the decision issued earlier this year by an Ontario court in respect of an option held by Energy Fundamentals Group Inc. ("EFG") to acquire up to 20% of Veresen's equity interest in the Jordan Cove LNG terminal. Veresen will not appeal this matter further and will determine the information to be provided to EFG in connection with the option in compliance with the terms of the original decision.

On April 15, 2015, Aux Sable received a Notice and Finding of Violation from the United States Environmental Protection Agency ("EPA") for exceedances of permitted limits for Volatile Organic Compounds at Aux Sable's Channahon, Illinois Facility. Aux Sable is engaged in discussions with the EPA to resolve the matter. The initial EPA proposal confirms the settlement will not be material to earnings.

On March 30, 2012, a Statement of Claim was filed against the Company's equity-accounted investees, Aux Sable Liquid Products, L.P., Aux Sable Canada L.P., Aux Sable Extraction LP and Aux Sable Canada Ltd., relating to differences in interpretation of certain terms of the NGL Sales Agreement. The Company's equity-accounted investees were served with this Statement of Claim on March 18, 2013. Further potential differences in interpretation of certain terms of the NGL Sales Agreement have also been identified on additional years not currently the subject of any claims. At this time, the Company is unable to predict the likely outcome of this matter. The Company will continue to assess the matter and the amount of loss accrued may change in the future.

17. Financial Instruments and Risk Management

Financial Instruments

The following table summarizes the Company's financial instrument carrying and fair values as at December 31, 2015:

	Financial assets at cost or amortized cost	Financial liabilities at amortized cost	Non-financial instruments	Total	Fair value ⁽¹⁾
Assets					
Cash and short-term investments	58			58	58
Restricted cash	7			7	7
Distributions receivable	52			52	52
Accounts receivable and other	23		5	28	23
Due from jointly-controlled businesses	50			50	50
Investments held at cost	1,981			1,981	2,010
Other assets	12		1	13	12
Liabilities					
Accounts payable and other		65		65	65
Dividends payable		25		25	25
Senior debt		1,100		1,100	1,143
Other long-term liabilities		9	27	36	9

(1) Fair value excludes non-financial instruments.

The following table summarizes the Company's financial instrument carrying and fair values as at December 31, 2014:

	Financial assets at cost or amortized cost	Financial liabilities at amortized cost	Non-financial instruments	Total	Fair value ⁽²⁾
Assets					
Cash and short-term investments	51			51	51
Restricted cash	5			5	5
Distributions receivable	46			46	46
Accounts receivable and other	55			55	55
Due from jointly-controlled businesses	44			44	44
Assets held for sale	6		33	39	6
Investments held at cost	1,660			1,660	1,660
Other assets	1		17	18	1
Liabilities					
Accounts payable and other	69		2	71	69
Dividends payable	8			8	8
Liabilities associated with assets held for sale	4			4	4
Senior debt	1,811			1,811	1,864
Other long-term liabilities	14		39	53	14

(2) Fair value excludes non-financial instruments.

For the years ended December 31, 2015 and 2014 the following amounts were recognized in income:

	2015	2014
Total interest expense, recorded with respect to other financial liabilities, calculated using the effective rate method	53	59

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, distributions receivable, receivables and accrued receivables, due from jointly-controlled businesses, other assets, payables, interest payable, accrued payables, dividends 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 value of the investment held at cost is based on a number of factors, including the present value of anticipated distributable cash flows to be produced from the underlying operations of the Ruby investment. Assessing these cash flows required the use of assumptions related to the future demand for Ruby's operations, forecasted commodity prices and interest rates, anticipated economic conditions, timing of conversion of the preferred interest into a common equity interest, and other inputs, many of which are not available as observable market data. The fair values of senior debt are 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.

The carrying value of investments held at cost are accounted for under the cost method. As part of the Company's impairment review, the Company performs a fair value assessment of the Company's investments held at cost on an annual basis using the most currently available information.

US GAAP 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.

Veresen has categorized senior debt as Level 2. At December 31, 2015 senior debt had a carrying value of \$1,100 million (December 31, 2014 – \$1,811 million) and fair value of \$1,143 million (December 31, 2014 – \$1,864 million). The investment held at cost is categorized as Level 3. At December 31, 2015 the investment held at cost had a carrying value of \$1,981 million (December 31, 2014 – \$1,660 million) and a fair value of \$2,010 million (December 31, 2014 – \$1,660 million).

Financial instruments measured at fair value as at December 31, 2015 were:

	Level 1	Level 2	Level 3	Total
Cash and short-term investments		58		58
Restricted cash		7		7

Maturity Analysis of Financial Liabilities

The tables below summarize the Company's financial liabilities into relevant maturity groupings based on the remaining period at the balance sheet date to the contractual maturity date. The amounts disclosed in the table are the undiscounted cash flows.

The following table summarizes the maturity analysis of financial liabilities as of December 31, 2015:

	<1 year	1-3 years	4-5 years	Over 5 years
Accounts payable and other	65			
Dividends payable	25			
Senior debt	13	640	288	159
Other long-term liabilities		9		

The following table summarizes the maturity analysis of financial liabilities as of December 31, 2014:

	<1 year	1-3 years	4-5 years	Over 5 years
Accounts payable and other	71			
Dividends payable	8			
Liabilities associated with assets held for sale	4			
Senior debt	11	1,174	394	232
Other long-term liabilities		14		

Currency Risk

From time to time, the Company has utilized U.S.-denominated debt to hedge a portion of the net investment in its self-sustaining U.S. operations. To the extent these hedges were deemed to be effective, any such gains or losses were recorded in other comprehensive income. For the years ended December 31, 2015 and December 31, 2014, there were no net investment hedges.

On December 31, 2015, approximately 61% of the Company's total assets were denominated in U.S. dollars (2014 – 50%).

Foreign Exchange Hedge

In 2014, the Company entered into forward foreign exchange contracts to manage the foreign exchange exposure relating to the Ruby acquisition (note 4). For the year ended December 31, 2014, the Company recognized a \$39 million realized pre-tax gain associated with the forward foreign exchange contracts, included within foreign exchange and other in the consolidated statement of income. No such hedge was entered into during the year ended December 31, 2015.

Cross Currency Swaps

As at December 31, 2015, Veresen Midstream, a jointly-controlled business, had one cross currency swap ("Swap"). This Swap was entered into to manage the exposure to changes in interest rates and foreign exchange whereby Veresen Midstream receives variable interest rates denominated in US dollars and pays fixed interest rates denominated in Canadian dollars. The Swap had an initial notional amount of US\$575 million which declines over the 4 year swap facility, ending March 31, 2019. On May 28, 2015, resulting from the re-pricing of Veresen Midstream's US dollar denominated Term Loan, the Swap was amended and made effective March 31, 2015, resulting in a reduction of 75 basis points. Future changes in interest rates and exchange rates will affect the fair value of the Swap, impacting the amount of unrealized gains or losses included in equity income from jointly-controlled businesses recognized in the period.

The following is a summary of the cross currency swap in place as at December 31, 2015:

Jointly-Controlled Business	Variable Debt Interest Rate	Fixed Rate	Notional Amount ⁽¹⁾	Fair Value ⁽¹⁾	Term
Veresen Midstream	USD-BA-LIBOR	5.81%	\$383	\$32	March 31, 2015 to March 31, 2019

The fair values approximate the amount that Veresen Midstream would have either paid or received to settle the contract, and are included in the Company's investment in Veresen Midstream.

(1) Veresen's interest in Veresen Midstream varies for items recognized within the consolidated statement of financial position and the consolidated statement of income. For the purposes of recognizing items in the consolidated statement of financial position, Veresen's ownership interest is based on Veresen's holdings on a fully diluted basis, as at the date of the statement of financial position. As at December 31, 2015, this ownership interest is 48.5%. For the purposes of recognizing items in the consolidated statement of income, Veresen's ownership interest is based on the weighted average of Veresen's holdings on a fully diluted basis during the financial statement period. For the year ended December 31, 2015 this ownership interest is 49.6%.

Interest Rate Risk

At December 31, 2015, 13% of consolidated long-term debt was floating-rate debt (2014 – 47%).

Veresen and its jointly-controlled businesses periodically enter into interest rate hedges to manage interest rate exposures. As at December 31, 2015, York Energy Centre and Grand Valley II Limited Partnership ("Grand Valley II"), both jointly-controlled business, had interest rate hedges. Future changes in interest rates will affect the fair value of the hedges, impacting the amount of unrealized gains or losses included in equity income from jointly-controlled businesses recognized in the period. The following is a summary of the interest rate hedges in place as at December 31, 2015:

Jointly-Controlled Business	Variable Debt Interest Rate	Fixed Rate	Notional Amount ⁽²⁾	Fair Value ⁽²⁾	Term
York Energy Centre	CAD-BA-CDOR	4.36%	\$122	\$(22)	April 30, 2012 to June 30, 2032
Grand Valley II	CAD-BA-CDOR	2.31%	\$86	\$(2)	December 31, 2015 to December 31, 2033

The following is a summary of the interest rate hedge in place as at December 31, 2014:

Jointly-Controlled Business	Variable Debt Interest Rate	Fixed Rate	Notional Amount ⁽²⁾	Fair Value ⁽²⁾	Term
York Energy Centre	CAD-BA-CDOR	4.36%	\$126	\$(23)	April 30, 2012 to June 30, 2032

(2) Veresen's interest in the York Energy Centre and Grand Valley II jointly-controlled businesses is 50% and 75% respectively.

The fair values approximate the amount that York Energy Centre and Grand Valley II would have either paid or received to settle the contract, and are included in the Company's investments in York Energy Centre and Grand Valley II.

Credit Risk

Veresen and its jointly-controlled businesses are exposed to credit risk as revenues are dependent upon the ability of customers to fulfill their contractual obligations, the failure of which could adversely affect the ability of Veresen and its jointly-controlled businesses to recover operating and financing costs or make dividends or distributions, as applicable. Alliance and Ruby's businesses are concentrated in the natural gas transportation industry and their revenue is dependent upon the ability of their shippers to pay their monthly demand charges. Exposure to this credit risk is mitigated by requiring shippers to provide letters of credit or other suitable security unless the shippers maintain specified credit ratings or a suitable financial position. As at December 31, 2015, Alliance held \$69 million in letters of credit and cash deposits as security from its shippers.

AEGS is primarily dependent upon two customers, both large petrochemical companies with world-scale petrochemical facilities located in Alberta. AEGS represents a critical component in securing ethane feedstock for these petrochemical facilities.

In the case of the Veresen Midstream, the Company is dependent on Encana and CRP, a partnership between Encana and Cutbank Dawson Gas Resources Ltd., a subsidiary of Mitsubishi Corporation. Mitsubishi possesses an investment-grade credit rating. Encana is currently rated as investment grade with Standard & Poor's (BBB) and Dominion Bond Rating Service (BBB), while Moody's Investor Service has rated Encana as Ba2.

Aux Sable's earnings and cash flows are primarily dependent upon a long-term NGL Sales Agreement with a large, integrated energy company.

The counterparty exposures associated with the Company's Power business are diverse and are spread across numerous entities (including a number of government entities in the case of the Company's district energy facilities) and individual counterparties.

None of the Company's financial assets are past due or impaired, nor have any terms been renegotiated. The Company is satisfied with the credit quality of its financial assets. The maximum exposure to credit risk related to non-derivative financial assets is their carrying value, as disclosed previously in the table "Financial Instruments".

Liquidity Risk

Veresen and its businesses manage their liquidity requirements utilizing cash from operations, excess cash and undrawn committed credit facilities. The Company believes these sources of funding are sufficient to meet its expected liquidity requirements.

All financial liabilities classified as current on the balance sheet are expected to be settled within one year.

18. Segmented Information

Year ended December 31	Pipelines		Midstream		Power		Corporate ⁽¹⁾		Total	
	2015	2014	2015	2014	2015	2014	2015	2014	2015	2014
Equity income (loss)	131	112	(44)	48	4	(2)	(14)	(12)	77	146
Dividend income	116	16	–	–	–	–	–	–	116	16
Operating revenues	58	61	33	133	96	108	–	–	187	302
Operations and maintenance	(28)	(31)	(11)	(55)	(37)	(55)	–	–	(76)	(141)
General and administrative	(2)	(2)	(1)	(5)	(13)	(13)	(22)	(29)	(38)	(49)
Project development	–	–	–	–	–	–	(85)	(79)	(85)	(79)
Depreciation and amortization	(14)	(14)	(10)	(40)	(33)	(27)	(3)	(2)	(60)	(83)
Interest and other finance	(5)	(5)	–	–	(10)	(13)	(38)	(41)	(53)	(59)
Foreign exchange and other	–	–	–	–	3	–	5	41	8	41
Gain on sale of assets, net of impairment loss	–	–	37	–	–	–	–	9	37	9
Net income (loss) before tax from continuing operations	256	137	4	81	10	(2)	(157)	(113)	113	103
Tax expense ⁽²⁾	–	–	–	–	–	–	(19)	(25)	(19)	(25)
Net income (loss) from continuing operations	256	137	4	81	10	(2)	(176)	(138)	94	78
Discontinued operations										
Net loss before tax from discontinued operations	–	–	–	–	–	(16)	–	–	–	(16)
Tax recovery from discontinued operations	–	–	–	–	–	6	–	–	–	6
Net loss from discontinued operations	–	–	–	–	–	(10)	–	–	–	(10)
Net income (loss), before extraordinary loss	256	137	4	81	10	(12)	(176)	(138)	94	68
Extraordinary loss, net of tax	(10)	–	–	–	–	–	–	–	(10)	–
Net income (loss)	246	137	4	81	10	(12)	(176)	(138)	84	68
Preferred Share dividends	–	–	–	–	–	–	(24)	(16)	(24)	(16)
Net income (loss) attributable to Common Shares	246	137	4	81	10	(12)	(200)	(154)	60	52
Total assets ⁽³⁾	2,674	2,359	785	1,228	1,057	682	55	468	4,571	4,737
Capital expenditures ⁽⁴⁾	–	–	9	14	42	132	7	2	58	148

(1) Reflects unallocated amounts applicable to Veresen's head office activities.

(2) The Company holds its ownership interests in multiple business lines through partnerships, which are consolidated into various corporate entities. Consequently, the tax provision is determined on a consolidated basis and, as such, the Company is not able to present income tax by segment.

(3) After giving effect to intersegment eliminations and allocations to businesses.

(4) Reflects capital expenditures related only to wholly-owned and majority-controlled businesses.

	2015		
	Canada	U.S.	Total
Dividend income	–	116	116
Operating revenues from continuing operations	182	5	187
Equity income from jointly-controlled businesses	47	30	77
Investments held at cost	–	1,981	1,981
Investments in jointly-controlled businesses	734	578	1,312
Pipeline, plant and other capital assets	830	89	919
	2014		
	Canada	U.S.	Total
Dividend income	–	16	16
Operating revenues from continuing operations	295	7	302
Equity income from jointly-controlled businesses	63	83	146
Investments held at cost	–	1,660	1,660
Investments in jointly-controlled businesses	378	507	885
Pipeline, plant and other capital assets	1,432	72	1,504

Revenues earned from one customer within the Company's Midstream segment represent approximately 17% (2014 – 39%) of the Company's 2015 operating revenues. Within the Power segment, revenues earned from one customer represented 21% (2014 – 9%) of the Company's 2015 operating revenues. No other customer represents over 10% of operating revenues in 2015 or 2014.

19. Extraordinary Loss

The extraordinary after-tax loss of \$10 million represents the one-time net effect of the de-recognition of Alliance's regulatory assets and liabilities.

As Alliance received regulatory approval from the NEB and the FERC to advance its new services offering effective December 1, 2015, it will be exposed to potential variability in certain future costs and throughput volumes. As such, the majority of Alliance's operations no longer meet all of the criteria required for the continued application of rate regulated accounting under US GAAP, thereby requiring the de-recognition of its regulatory balances as at June 30, 2015. Certain expenditures in Alliance, as approved by the NEB, will continue to be accounted for in accordance with Accounting Standards Codification 980 – Regulated Operations.

20. Supplemental Cash Flow Information

	2015	2014
Accounts receivable	21	11
Accrued receivables	12	(7)
Other assets	8	(5)
Payables	(16)	11
Interest payable	–	(7)
Deferred revenue	1	1
Accrued payables	(4)	3
Changes in non-cash operating working capital from continuing operations	22	7

21. Due from Jointly-Controlled Business

On March 30, 2012, the Company provided a \$47 million amortizing term loan to Grand Valley, a jointly-controlled business. Principal and interest are payable on a quarterly basis. The loan bears interest of 5.2% and the maturity date is December 31, 2031. At December 31, 2015, the outstanding balance was \$42 million (2014 – \$44 million).

22. Subsequent Events

Dividends

On February 18, 2016, the Company declared a quarterly dividend of \$0.275 per share for the period ending March 31, 2016 in respect of the Series A Preferred Shares, payable on March 31, 2015 to shareholders of record on March 15, 2016.

On February 18, 2016, the Company declared a quarterly dividend of \$0.3125 per share for the period ending March 31, 2016 in respect of the Series C Preferred Shares, payable on March 31, 2015 to shareholders of record on March 15, 2016.

On February 18, 2016, the Company declared a quarterly dividend of \$0.3125 per share for the period ending March 31, 2016 in respect of the Series E Preferred Shares, payable on March 31, 2016 to shareholders of record on March 15, 2016.

On January 20, 2016 and February 18, 2016, the Company declared dividends of \$0.0833 per Common Share for each of January and February 2016, respectively. These dividends are payable on February 23, 2016 to shareholders of record on January 29, 2016, and March 23, 2016 to shareholders of record on February 29, 2016, respectively.

CORPORATE INFORMATION

Senior Officers

Stephen W.C. Mulherin
Chairman

Don L. Althoff
President and Chief Executive Officer

Tom A. Day
Senior Vice President, Operations

Theresa Jang
*Senior Vice President, Finance
and Chief Financial Officer*

Kevan S. King
*Senior Vice President,
General Counsel*

Darren D. Marine
*Senior Vice President,
Business Joint Ventures*

Jesse D. Marble
*Senior Vice President,
Corporate Development and Strategy*

Elizabeth G. Spomer
*Executive Vice President,
President and CEO,
Jordan Cove LNG*

Directors

J. Paul Charron ^(2, 3)
Calgary, Alberta

Maureen E. Howe ^(1, 2)
Vancouver, British Columbia

Robert J. Iverach ^(2, 4)
Calgary, Alberta

Rebecca A. McDonald ^(1, 4)
Houston, Texas

Stephen W.C. Mulherin ^(2, 3)
Calgary, Alberta

Henry W. Sykes ^(3, 4)
Calgary, Alberta

Bertrand A. Valdman ^(1, 3)
Medina, Washington

Thierry Vandal ^(1, 4)
New York, New York

Don L. Althoff
Calgary, Alberta

(1) Member of the Audit Committee

(2) Member of the Corporate Governance and Nominating Committee

(3) Member of the Compensation Committee

(4) Member of the Environmental, Health and Safety Committee

Publicly Traded Securities

Listed on the Toronto Stock Exchange:

Common Shares

Trading Symbol: VSN

Dividend: Monthly

Record Date: Last business day of each month

Payment Date: 23rd day of the month following the
record date or, if not a business day,
the prior business day

Preferred Shares, Series A

Trading Symbol: VSN.PR.A

Fixed cumulative dividends at an annual rate of 4.40%,
payable quarterly

Preferred Shares, Series C

Trading Symbol: VSN.PR.C

Fixed cumulative dividends at an annual rate of 5.00%,
payable quarterly

Preferred Shares, Series E

Trading Symbol: VSN.PR.E

Fixed cumulative dividends at an annual rate of 5.00%,
payable quarterly

Transfer Agent and Registrar

Computershare Trust Company of Canada
600, 530 – 8th Avenue S.W.
Calgary, Alberta T2P 3S8

Phone: 1-800-564-6253

Toll Free Fax: 1-888-453-0330

Notice of Annual Meeting

2:00 pm, May 4, 2016

Livingston Club Conference Centre,
Livingston Place (South Tower)
Plus 15, 222 – 3rd Avenue S.W.
Calgary, Alberta

All shareholders are invited to attend.

VERESEN

Financial Report 2015

Veresen Inc.
Suite 900 Livingston Place South Tower
222 – 3rd Avenue SW
Calgary AB T2P 0B4