Veresen Inc.

Annual Information Form

Year Ended December 31, 2015

March 14, 2016

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WHAT IS THIS ANNUAL INFORMATION FORM?

Veresen Inc. is required by Canadian securities laws to file an Annual Information Form each year. The Annual Information Form is a disclosure document intended to provide material information about us and our business at a point in time in the context of our historical and possible future development. This Annual Information Form describes our company, operations and prospects, risks and other external factors that impact us specifically.

The disclosure in this Annual Information Form is supplemented throughout the year by subsequent continuous disclosure filings including news releases, financial statements and management's discussion and analysis and, where applicable, material change reports and business acquisition reports.

Unless otherwise noted, information is provided as at December 31, 2015.

All capitalized words used in this Annual Information Form which are not otherwise defined herein shall have the meanings ascribed thereto under *"Defined Terms"* in Appendix A.

ADDITIONAL INFORMATION ABOUT US

Our Information Circular dated March 16, 2015 relating to our annual meeting of holders of our common shares (Common Shares) held on May 6, 2015 and our Information Circular dated March 14, 2016 relating to our annual meeting of holders of Common Shares to be held on May 4, 2016, once filed, provide additional information about us, including:

- compensation and indebtedness of the directors and certain executive officers;
- the principal holders of our Common Shares; and
- securities authorized for issuance under our equity compensation plans, if any.

Our 2015 Financial Report, which includes our Management's Discussion and Analysis and our audited consolidated financial statements as at and for the year ended December 31, 2015, gives more financial information about us.

This Annual Information Form, the above noted Information Circulars and our 2015 Financial Report, are available, or will be available, as applicable, on our website at www.vereseninc.com and under our profile on SEDAR at www.sedar.com.

REFERENCES TO LEGISLATION

All references to legislation or policies of government agencies in this Annual Information Form include any amendments to such legislation or policies. References to legislation also include any regulations issued under such legislation.

CURRENCY REFERENCES AND EXCHANGE RATES

All references to "$" or "dollars" in this Annual Information Form are references to Canadian dollars unless otherwise noted. The noon-day Canadian to US dollar exchange rates for Cdn. $1.00, as reported by the Bank of Canada, were:

	2015	2014	2013	2012	2011
			(US$ per Cdn. $1.00)		
December 31	1.3840	0.8620	0.9402	1.0051	0.9833
Average	1.2787	0.9054	0.9710	1.0004	1.0111
High	1.3990	0.9422	1.0164	1.0299	1.0583
Low	1.1728	0.8589	0.9348	0.9599	0.9430

On March 14, 2016, the noon-day exchange rate was US $1.3293 per Cdn. $1.00.

FORWARD-LOOKING INFORMATION

Some of the information in this Annual Information Form is forward-looking information under Canadian securities laws. All statements, other than statements of historical fact included in this Annual Information Form which address activities, events or developments that we expect or anticipate may or will occur in the future, are 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 Annual Information Form include statements about the:

- anticipated cost to purchase GHG emission credits for the Alliance Pipeline and the adequacy of steps taken to mitigate environmental effects;
- utilization of the Alliance Pipeline under the new services framework;
- impact of growth initiatives being pursued by Aux Sable US;
- impact of Canadian and US federal and provincial emissions regulations on the Alliance Pipeline;
- timetable for the introduction of climate change proposals and regulations in Canada and the US;
- sources and timing of additional ethane supplies for transportation on AEGS and future ethane demand;
- NGL available to Aux Sable for processing sourced from shale developments;
- projected construction and in-service dates for, and utilization of, our power and Veresen Midstream facilities under construction, the proposed ethane storage facility and development of the Channahon facility fractionation expansion;
- emissions credit positions of our power and district energy facilities;
- development opportunities for us and each of our businesses;

- timing of and obtaining of regulatory approvals, the sources of natural gas available and possible strategic partners and customers for our Jordan Cove LNG terminal and Pacific Connector gas pipeline projects; and

- timing and scale of any new projects or funding requirements for Veresen Midstream's previous commitments of up to $5 billion of new projects.

The following discussion identifies certain factors, although not necessarily all factors, which could cause future outcomes to differ materially from those set forth in the forward-looking information. The risks and uncertainties that may cause actual results to vary from forward-looking information or may affect the operations, performance, development and 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 is included in our filings with the securities commissions or similar authorities in each of the provinces of Canada.

We caution you that this list of factors and risks is not exhaustive. The effect of any one risk, uncertainty or factor on a particular forward-looking statement is uncertain because these factors are independent and management's future course of action will depend on our assessment of all information at that time. Although we believe that the expectations in the forward-looking information are reasonable based on information currently available to us, we can give no assurances on future results, levels of activity and achievements.

You should not place undue reliance on the forward-looking information contained herein, as actual results achieved will vary from the forward-looking information provided herein and the variations may be material. We do not promise that actual results will be the same in whole or in part as those set out in

the forward-looking information. Furthermore, the forward-looking statements herein are made as of the date of this Annual Information Form, and, except as required by applicable law, we may not update publicly or revise any forward-looking information.

This cautionary statement qualifies all forward-looking information in this Annual Information Form.

VERESEN INC.

Veresen Inc. was incorporated as 1560941 Alberta Ltd. on October 1, 2010 pursuant to the provisions of the *Business Corporations Act* (Alberta) (ABCA). On October 15, 2010, 1560941 Alberta Ltd. filed articles of amendment to change its name to Veresen Inc. 1560941 Alberta Ltd. was incorporated for the sole purpose of participating in a plan of arrangement (Arrangement) whereby Fort Chicago Energy Partners L.P. (Fort Chicago) was converted to a corporate structure, as Veresen Inc., effective January 1, 2011. The principal place of business and registered office of Veresen Inc. is located at Suite 900, Livingston Place, 222 – 3rd Avenue S.W., Calgary, Alberta, Canada, T2P 0B4.

EMPLOYEES

On December 31, 2015, we had 259 employees as set forth below [(1)]:

Pipeline Business	2
Midstream Business	67
Power Business	78
Corporate Office[(2)]	112
Total	259

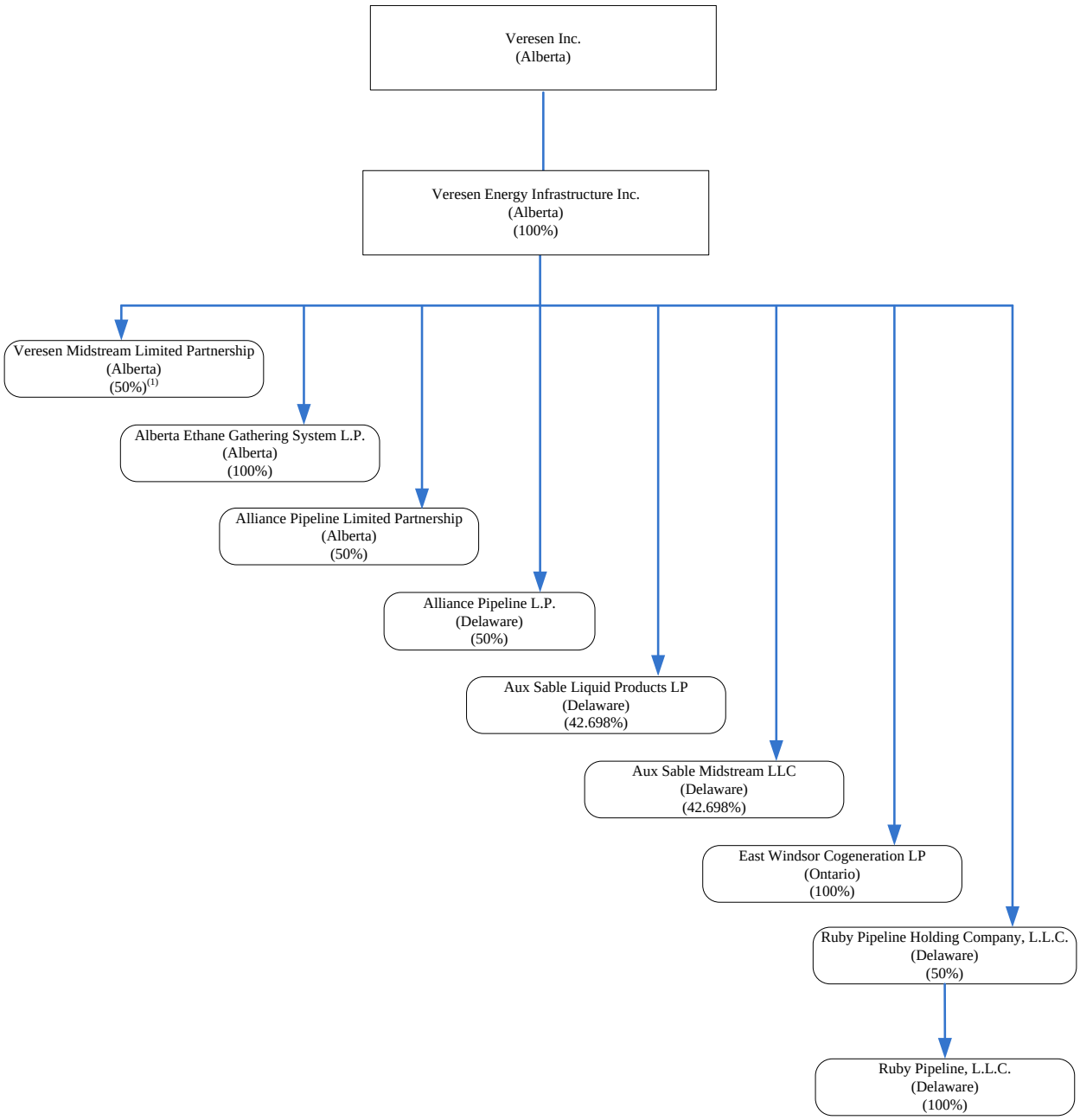
Note:

(1) Our Pipeline Business assets, and certain of our Midstream Business assets and Power Business assets are not operated by us.

(2) This includes 93 employees located in the Calgary Corporate Office, together with 19 employees located in Houston, Texas in connection with our Jordan Cove LNG project.

SUBSIDIARIES AND OPERATING ENTITIES

The following organization chart presents the name and jurisdiction of incorporation or organization of, and our direct or indirect ownership interest in the voting securities of, each of our principal subsidiaries and operating entities that had total assets that exceeded 10% of our total consolidated assets, or revenues that exceeded 10% of our total consolidated revenues, as of the date hereof. The chart does not include all of our subsidiaries or operating entities. The aggregate assets and revenues of the excluded subsidiaries and operating entities did not exceed 20% of our total consolidated assets or total consolidated revenues as of the date hereof.



Note:

(1) Percentage is on an undiluted basis.

GENERAL DEVELOPMENT OF OUR BUSINESS

The following describes the general development of our business over the last three financial years and the significant acquisitions, dispositions, events or conditions that have had an influence on that development.

2016 Developments

March – The Federal Energy Regulatory Commission (FERC) denies the applications seeking authorization for construction and operation of the Jordan Cove LNG export terminal and Pacific Connector Gas Pipeline and we announce that Jordan Cove LNG and Pacific Connector Gas Pipeline will file a request for a rehearing of this decision.

March – Construction by Veresen Midstream of the $930 million Saturn Phase 2 gas processing facility in the Montney is sanctioned by Cutbank Ridge Partnership (CRP).

February – Alliance consulted with shippers in December 2015 and January 2016 and as a result submitted a consultation report to the NEB and filed a revised tariff for final NEB approval.

2015 Developments

December – Construction by Veresen Midstream of the $715 million Tower rich gas processing complex in the Montney is sanctioned by CRP.

December – Grand Valley Wind Farm Phase III is placed into service.

December – Alliance's new services offerings come into effect.

November – We announce our intention to build and operate a wholly-owned ethane storage facility to be located near Burstall, Saskatchewan with an approximate capacity to store 1 million bbls of ethane. See "*Other Initiatives – Ethane Storage Facility*".

November – The NEB approves Alliance's filed tariff to implement the new services for December 1, 2015 on an interim basis and directs Alliance to conduct further consultations with its shippers and then refile its tariff for final approval in early 2016.

November – The FERC issues an Order on Rehearing directing Alliance to reinstate Authorized Overrun Service (AOS), but relegated the scheduling and curtailment priority of AOS to the same as that for interruptible service.

October – Construction by Veresen Midstream of the $860 million Sunrise gas plant in the Montney is sanctioned by CRP.

October – Alliance Canada files a notice with the NEB regarding a planned new interconnection into its mainline in northwestern Alberta which will be capable of receiving flows of up to 100 mmcf/d.

September – Timothy Stauft resigns as President and Chief Executive Officer of Aux Sable. Tom Day is appointed President and Chief Executive Officer of Aux Sable and resigns as Senior Vice President, Operations of Veresen Inc.

September – FERC issues a final Environmental Impact Statement for Jordan Cove LNG and Pacific Connector Gas Pipeline.

August – Alliance experiences a short-term shutdown of its mainline pipeline system due to the entry of H_2S into the pipeline from an upstream operator.

August – The Precedent Agreement Process of Alliance ends with all remaining residual firm transportation capacity, and winter seasonal capacity for the December 1, 2015 to March 31, 2016 term, to be offered in a future open season targeted for the third quarter of 2015.

July – Commercial operations commence at our St. Columban wind facilities.

July – The NEB issues its Reasons for Decision approving Alliance Canada's new services offering tolls and tariff.

July – The Ontario Court of Appeal denies our appeal of a portion of the prior decision issued by an Ontario Court relating to an application by Energy Fundamentals Group Inc. (EFG) to acquire up to 20% of our equity interest in the Jordan Cove LNG terminal and related assets granted to EFG pursuant to a 2005 letter agreement (EFG Option).

June – We receive a revised notice of schedule from the FERC advising that the final Environmental Impact Statement for our Jordan Cove LNG and Pacific Connector Gas Pipeline projects is to be issued on September 30, 2015.

June – The FERC issues an Order pursuant to which it accepted, and suspended until December 1, 2015, the amended tariff filed, subject to the outcome of a hearing.

May – Commercial operations commence at our Dasque Middle run-of-river hydro facility.

May – Alliance Canada files an application with the NEB for regulatory approval of the Canadian tolls and tariff provisions Alliance needs to implement for its new services offering, to be effective December 1, 2015.

May – Alliance US applies to the FERC for regulatory approval of amendments to its FERC gas tariff.

May – Thierry Vandal is elected to our Board of Directors.

April – We complete a public offering of 8,000,000 Cumulative Redeemable Preferred Shares, Series E at a price of $25.00 per share for gross proceeds of $200 million.

April –Veresen Midstream closes the acquisition of certain natural gas gathering and compression assets supporting Montney development in the Dawson Creek, British Columbia area (Veresen Midstream Transaction) from Encana Corporation (Encana) and CRP, which transaction includes an undertaking by Veresen Midstream of up to $5 billion of new midstream expansion in the Montney for Encana and CRP.

April – Alliance advises that it no longer has existing capacity to offer non-staged, three year or longer, Zone 2, Firm Receipt Service or Firm Full Path Service commencing December 1, 2015.

March – We appeal a portion of the decision of the Ontario Superior Court of Justice that requires certain information be provided to EFG in connection with the EFG Option.

February – The Ontario Superior Court of Justice renders its decision that the EFG Option continues to apply to our proposed Jordan Cove LNG export terminal.

February – We receive a notice of schedule from the FERC advising that the final Environmental Impact Statement for our Jordan Cove LNG and Pacific Connector Gas Pipeline project will be issued on June 12, 2015, instead of February 27, 2015 as set out in the first notice of schedule from the FERC.

2014 Developments

December – Veresen Midstream is created, and enters into agreements to acquire certain natural gas gathering and compression assets in connection with the Veresen Midstream Transaction.

December – Alliance advises existing and prospective shippers that it no longer has capacity to offer non-staged, three year or longer, Zone 1, Firm Receipt Service or Firm Full Path Service commencing December 1, 2015.

December – NRGreen completes its Whitecourt Recovered Energy Project and places the power generation facility into commercial operation.

November – Aux Sable Canada enters into a long-term Rich Gas Premium (RGP) Agreement with Encana and Brion Duvernay Gas Partnership (previously named Phoenix Duvernay Gas, a joint venture participant of Encana) which provides for rich gas supply of up to 180 mmcf/d of additional rich gas supply from the emerging Duvernay shale play to the Channahon facility starting in November 2017 and continuing through to 2020.

November – The FERC issues a draft Environmental Impact Statement assessing our Jordan Cove LNG terminal and the related Pacific Connector Gas Pipeline.

November – We complete the acquisition from Global Infrastructure Partners (GIP) of a 50% convertible preferred interest in the entity that owns the Ruby Pipeline system. A business acquisition report on Form 51-102F4 was filed on November 21, 2014 in respect of the acquisition and can be accessed via SEDAR at www.sedar.com. In connection with the completion of the acquisition, our previously issued 56,120,000 subscription receipts are converted to Common Shares.

November – Aux Sable Liquid Products LP announces a US$130 million growth project to increase fractionation capacity at its extraction and fractionation facilities in Channahon by approximately 24,500 bpd to 131,500 bpd. The fractionation expansion has a target in-service date of mid-2016.

October – Elizabeth Spomer is appointed President and Chief Executive Officer of Jordan Cove LNG LLC, an indirect wholly-owned subsidiary of Veresen Inc., and Executive Vice President of Veresen Inc.

October – We redeem all of our outstanding 5.75% Convertible Unsecured Subordinated Debentures, Series C.

October – We complete a public offering of 56,120,000 subscription receipts at a price of $16.40 per subscription receipt for gross proceeds of approximately $920 million in order to partially finance our acquisition of a 50% convertible preferred interest in the Ruby Pipeline system.

September – We enter into an agreement with GIP to acquire GIP's 50% convertible preferred interest in the entity that owns the Ruby Pipeline system for US$1.425 billion.

September – Alliance advises members of its shipper task force that it will increase Zone 1 available receipt capacity for Firm Receipt Service and Firm Full Path Service to a maximum of 1 bcf/d.

August – We are named a respondent in an Ontario Superior Court of Justice application by EFG seeking a declaration that the EFG Option is valid.

July – We redeem all of our outstanding $200 million aggregate principal amount of 5.60% senior unsecured notes Series 1 due July 28, 2014.

June – We complete a public offering of $200 million principal amount of 3.06% medium term notes, series 4 due 2019.

June – Aux Sable Canada enters into a long-term RGP Agreement with Seven Generations Energy Ltd. increasing the volume originally agreed to by the parties in 2013 to an expected volume of up to 500 mmcf/d.

June – Theresa Jang is appointed our Senior Vice President, Finance and Chief Financial Officer.

May – Alliance Pipeline files an application with the NEB for regulatory approval of the tolls and tariff provisions of its proposed new services.

April – We complete a public offering of 17,250,000 Common Shares at a price of $16.50 per Common Share for gross proceeds of $284.6 million.

March – We receive a conditional order from the US Department of Energy to export LNG from our proposed Jordan Cove LNG export terminal to those countries that do not have Free Trade Agreement status with the United States.

March – Aux Sable Canada enters into long-term RGP Agreements with Encana and Phoenix Duvernay Gas (a joint venture participant of Encana) which provide for rich gas supply of up to 195 mmcf/d to the Channahon facility starting in July 2014 and continuing through to 2020.

February – The NEB approves our application for a long-term licence to export 1.55 bcf/d of natural gas from Canada to the US for 25 years in connection with our proposed Jordan Cove LNG export project.

January – Richard Weech resigns as Senior Vice President, Finance and Chief Financial Officer and Theresa Jang, our Vice President, Finance and Risk Management, is appointed interim Chief Financial Officer.

January – Timothy Stauft is appointed President and Chief Executive Officer of Aux Sable, replacing William McAdam who retired in December 2013.

2013 Developments

December – Shippers representing approximately six percent of firm capacity on the Alliance Pipeline elect to extend their existing commercial contracts from December 1, 2018 to at least December 1, 2019.

November –Crew Energy Inc. (Crew) exercises its option to repurchase 50% of the Septimus Gas Plant in the Montney region of northeast British Columbia, which repurchase became effective January 2014.

October – We complete a public offering of 6,000,000 Cumulative Redeemable Preferred Shares, Series C for gross proceeds of $150 million.

October – Our Jordan Cove project-level subsidiaries enter into non-binding Heads of Agreement with three large-scale prospective customers, which set out indicative commercial terms for liquefaction tolling services.

September – Alliance declares in-service its new 80-mile Tioga Lateral natural gas pipeline (defined below) in western North Dakota, which runs from an existing Hess Corporation (Hess) gas processing facility near Tioga, North Dakota and ties into the Alliance mainline near Sherwood, North Dakota.

September – Aux Sable Midstream and Summit Midstream Partners LP announce a new gas supply agreement which includes up to 25 mmcf/d of supply from North Dakota to be delivered to Aux Sable

Midstream's Palermo Conditioning Plant (previously known as the Stanley Condensate Recovery Plant) and Prairie Rose pipeline, and processed at the Channahon facility.

September – We file an application with the NEB for a long-term license to export natural gas from Canada to the US to supply our proposed Jordan Cove LNG export project.

September – We appoint David Pope as Executive Vice President, Chief Commercial Officer and Thomas Day as Senior Vice President, Operations of Veresen Inc.

August – Aux Sable appoints Clint White as Vice President Finance and Chief Financial Officer.

July – Alliance offers capacity on its natural gas transportation system for transportation services effective December 1, 2015 through a binding precedent agreement process commencing August 15, 2013.

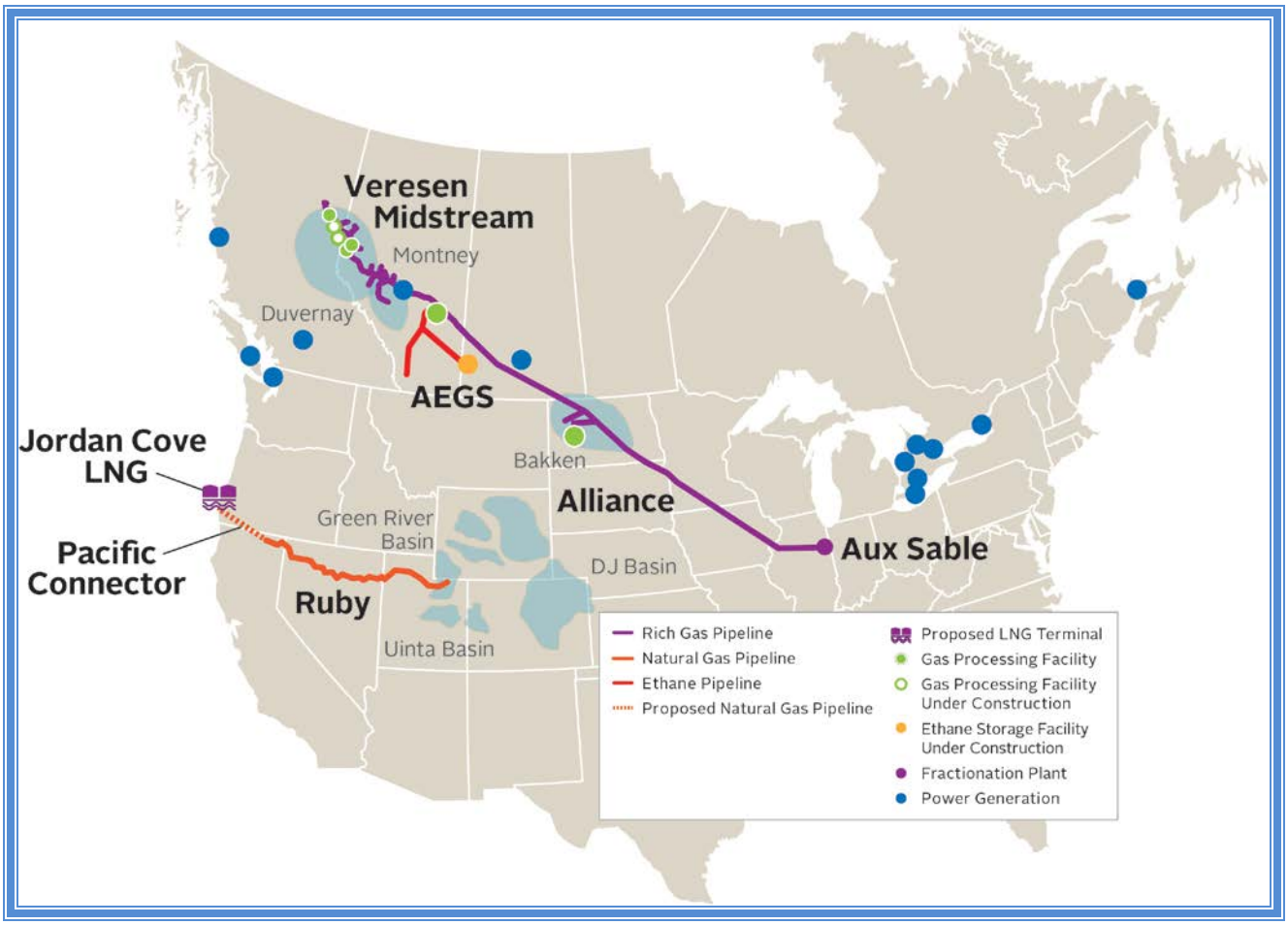
May – We file an application with the FERC to construct and operate our Jordan Cove LNG export facility.

April – Alliance Canada files a facilities application with the NEB for the installation of a second meter run at the Moose River Meter Station in northwestern Alberta, for the purpose of increasing the station's receipt capacity to 260 mmcf/d.

April – David Holm resigns as our Executive Vice President, Corporate and Business Development.

Map of Our Assets and Projects

Below is a map showing the location of each of our assets and our projects in development.



Overview of Our Businesses

We are a publicly traded corporation based in Calgary, Alberta, that owns and operates energy infrastructure assets across North America. We are engaged in three principal businesses:

(a) a pipeline transportation business comprised of interests in three pipeline systems, the Alliance Pipeline, the Ruby Pipeline and the Alberta Ethane Gathering System;

(b) a midstream business comprised of a partnership interest in Veresen Midstream, which owns assets in western Canada and an ownership interest in Aux Sable, which owns a world-class NGL extraction facility near Chicago and other natural gas and NGL processing facilities; and

(c) a power business comprised of a portfolio of assets primarily in Canada.

We, and each of our Pipeline, Midstream and Power Businesses, are also actively developing a number of projects including the Jordan Cove LNG terminal proposed to be constructed in Coos Bay, Oregon, and the Pacific Connector Gas Pipeline proposed to originate in Malin, Oregon and terminate at the Jordan Cove LNG terminal (see "*Jordan Cove Energy Project and Pacific Connector Gas Pipeline*"), and the ethane storage facility currently under construction near Burstall, Saskatchewan (see "*Other Initiatives – Ethane Storage Facility*").

In the normal course of business, we, and each of our businesses, regularly evaluate and pursue acquisition and development opportunities. The evaluation and pursuit of such opportunities may require, among other things, the execution of agreements, the transfer of assets to new entities and the development of business relationships with one or more strategic partners.

The following table shows our revenues from operations (excluding equity income from our jointly-controlled businesses) by business segment for the years ended December 31, 2015 and 2014.

Revenues From Operations *($ millions)*	**2015**	**2014**
Pipeline Business	57.9	61.3
Midstream Business	32.6	132.9
Power Business	96.0	144.1
Total Revenues	186.5	338.3

OUR PIPELINE BUSINESS

Map of Our Pipeline Business

Overview of Our Pipeline Business

Our Pipeline Business is comprised of:

(a) a 50% interest in the Alliance Pipeline, which is an integrated pipeline system consisting of an approximately 3,850 km high pressure natural gas mainline pipeline located in Canada and the US, a series of lateral pipelines located in Canada, the Tioga Lateral pipeline in North Dakota, and related infrastructure;

(b) a 50% convertible preferred interest in the Ruby Pipeline, a 680-mile, 42-inch natural gas transmission pipeline; and

(c) a 100% interest in the Alberta Ethane Gathering System, a 1,330 km pipeline that transports purity ethane within Alberta from various ethane extraction plants to major petrochemical complexes located near Joffre and Fort Saskatchewan, Alberta.

Alliance Pipeline

All dollar amounts and other figures presented in this section reflect 100% of Alliance's interest therein and have not been adjusted to reflect our proportionate share.

Overview

The Alliance Pipeline consists of an approximately 3,850 km integrated high pressure natural gas mainline pipeline located in Canada and the US, a series of lateral pipelines located in Canada, the Tioga Lateral pipeline located in North Dakota, and related infrastructure. The Alliance Canada Pipeline is comprised of an approximately 1,560 km natural gas mainline pipeline, approximately 730 km of lateral pipelines connected to the pipeline's mainline and 59 receipt point locations, primarily at natural gas processing facilities in northwestern Alberta and northeastern British Columbia (with one receipt point in southeastern Saskatchewan) and related infrastructure. The Alliance US Pipeline consists of an approximately 1,429 km natural gas mainline pipeline, a 129 km lateral in North Dakota, three receipt points (one at the international border, and two in North Dakota), 11 delivery points (two in North Dakota, one in Iowa and eight along the delivery header near Chicago) and related infrastructure owned by Alliance US. The Alliance Canada Pipeline and the Alliance US Pipeline are connected at the Canada-US border near Elmore, Saskatchewan and operate as an integrated pipeline system.

The Alliance Pipeline connects in the Chicago area with two local natural gas distribution systems and five interstate natural gas pipelines, which provide shippers with access to natural gas markets in the mid-western and northeastern US, and eastern Canada. The Alliance Pipeline connects with the Aux Sable NGL extraction facility in Channahon, Illinois, near the terminus of the Alliance Pipeline, which extracts NGL from the natural gas transported on the system. All shippers have signed extraction agreements that give Aux Sable the exclusive right to extract the NGL from the rich gas transported on the Alliance Pipeline. The Alliance Pipeline also has three connections, two in North Dakota and one in Iowa, to provide for deliveries of small amounts of natural gas to ethanol production plants.

The Alliance Pipeline facilities include 14 mainline compressor stations that operate between approximately 31,000 hp and 46,000 hp each, spaced at approximately 193 km intervals. The Alliance Pipeline's facilities also include mainline block valves, spaced, on average, at 32 km intervals, operating and maintenance facilities, and an associated SCADA system.

New Services Framework

On December 1, 2015 Alliance commenced the implementation of its new services framework. The new services framework offers shippers competitive fixed tolls for terms out to ten years and biddable tolls for interruptible and seasonal service. This framework responds to current market requirements and the diverse needs of existing and prospective shippers. The new services offerings include both full-path and segmented services with a new Canadian trading pool and a revised hydrocarbon dewpoint specification, which will facilitate the transportation of higher heat content natural gas.

On May 22, 2014, Alliance Canada filed an application with the NEB for regulatory approval of the new services framework tolls and tariff provisions, effective December 1, 2015. Similarly, Alliance US applied to the FERC on May 29, 2015 for regulatory approval of amendments to its FERC Gas Tariff, to be effective December 1, 2015.

On July 9, 2015, the NEB issued its Reasons for Decision approving Alliance Canada's new services offering tolls and tariff, subject to certain directions and conditions. The conditions included restrictions on Alliance Canada's discretion to set bid floors for seasonal and interruptible service to no more than 125% of the corresponding firm service toll, and on Alliance Canada's ability to discount seasonal service below the corresponding firm service toll. On November 26, 2015, the NEB approved Alliance's filed tariff implementing the new services for December 1, 2015 on an interim basis. The NEB also directed Alliance to conduct further consultations with its shippers and to then refile its tariff for final approval by February 1, 2016.

On May 29, 2015, Alliance US filed revised tariff provisions in support of its new services, including the removal of AOS. On June 30, 2015 the FERC issued an Order pursuant to which it accepted and suspended, until December 1, 2015, the amended tariff records filed, subject to refund, and subject to the outcome of a hearing. The FERC found that due to the nature of certain of Alliance's proposed tariff amendments, the filing was similar to a Section 4 rate case, and set the matter for hearing, and ordered the filing of additional supporting materials. On November 19, 2015, the FERC issued an Order on Rehearing directing Alliance to reinstate AOS, but relegated the scheduling and curtailment priority of AOS to the same as that for interruptible service.

Alliance Canada has recontracted all of its year-round firm receipt capacity through 2018, and approximately 90% of firm receipt capacity in 2019 and 2020, with average contract durations of 5.3 years. Following this successful marketing of Alliance's initial firm contracts effective December 1, 2015, demand for Alliance's services has been excess of available capacity. Alliance has successfully contracted winter and summer seasonal firm contracts as well as short-term firm contracts, all through a bidding process, to capture this strong demand for transportation services. Alliance has also successfully marketed available interruptible transportation service.

Shippers on Alliance

As of December 31, 2015, there were 28 long-term firm shippers on the Alliance Pipeline in Canada and 20 long-term firm shippers in the US. The total quantity of firm transportation contracted to the Canadian border is 1.48 bcf/d, and 1.62 bcf/d in the US. In addition, Alliance sells interruptible service. Long term receipt and full path shippers in Canada are also able to nominate Priority Interruptible Service for up to 25% of their contracted capacity, if available.

In 2015, Alliance shippers continued to use substantially all of the available capacity offered by Alliance. Prior to December 1, 2015, Alliance provided firm take-or-pay transportation services under cost-of-

service contracts. Commencing December 1, 2015, Alliance Canada began operating under its new service framework with fixed term differentiated tolls for its take-or-pay transportation services.

No single permanent shipper represents more than 24% of the firm transportation revenues on the Alliance Pipeline. The ten largest shippers, in terms of transportation revenues, represent approximately 85% of the firm transportation revenues of the Canadian portion and 84% of the US portion of the Alliance Pipeline. Owners or affiliates of owners of Alliance and Aux Sable account for approximately 29% of the firm transportation revenues on the Canadian portion and approximately 30% on the US portion.

Credit Status of Alliance Shippers

Alliance reviews the credit status of each shipper at least quarterly and determines whether the shipper or applicable guarantor possesses sufficient credit. If the shipper or its guarantor has a long-term senior unsecured debt rating assigned by any one of the following applicable credit rating agencies:

(a) DBRS Limited ("DBRS") rating of at least BBB;

(b) Moody's Investor Service, Inc. ("Moody's") rating of at least Baa3;

(c) Standard & Poor's Rating Services ("S&P") rating of at least BBB-,

the shipper is considered to possess the required creditworthiness. If a shipper or its guarantor possesses insufficient credit, the shipper is required to post security.

The credit status of each shipper is classified into one of the following categories:

(a) "Investment Grade Rating" means a shipper or its respective guarantors, if applicable, or a shipper's senior unsecured securities, that has a credit rating of any of the following, as applicable: (i) "Baa3" or better from Moody's Investors Service, Inc. (Moody's); (ii) "BBB-" or better from Standard & Poor's Rating Services (S&P); or (iii) "BBB" or better from DBRS Limited (DBRS);

(b) "Acceptable Credit Status" means a shipper, or its respective guarantors, if applicable, that does not have an Investment Grade Rating, but is of sufficient financial strength that Alliance does not require such shipper to post security for such shipper's obligations to Alliance; or

(c) shippers who do not have an Investment Grade Rating or Acceptable Credit Status and have, in accordance with the terms of the transportation contracts, either posted security in the form of letters of credit or cash equal to 12 months (reduced to 3 months, commencing December 1, 2015) of demand and reservation charges, or have made other credit support arrangements satisfactory to Alliance and its lenders.

The following is a summary percentage of contracted capacity for Alliance Canada and Alliance US and credit status of the shippers, or their respective guarantors, as at December 31, 2015:

Alliance Canada Shippers	Number of Shippers	Percentage of Contracted Capacity
Investment Grade Rating	10	41.3
Acceptable Credit Status	4	16.5
Security Required	14	42.2
Total	28	100.0

Alliance US Shippers	Number of Shippers	Percentage of Contracted Capacity
Investment Grade Rating	10	60.1
Acceptable Credit Status	2	9.8
Security Required	8	30.1
Total	20	100.0

Expansion Capability

The Alliance Pipeline is designed to be able to cost-effectively increase the firm transportation capability by approximately 30% by adding compression facilities, including up to 14 new compressor stations. Larger expansions of firm transportation capability are possible through the construction of parallel pipelines and additional compression facilities. An expansion is not imminent. Alliance will not decide to expand the pipeline until it is satisfied that sufficient market demand exists and it has arranged financing for the expansion. Any expansion would also require regulatory approval in either or both of Canada and the US.

Regulation in Canada

The NEB exercises jurisdiction over all international and interprovincial pipelines in Canada pursuant to the *National Energy Board Act* (Canada) (NEB Act). Under such legislation, the NEB has jurisdiction with respect to virtually all commercial aspects of Alliance Canada's business, including in relation to toll and tariff matters and the construction of new facilities.

The NEB approved Alliance's new services framework for services commencing December 1, 2015, that consists of full-path and segmented transportation services along with a fixed toll construct for firm service out to a term of ten years and biddable tolls for seasonal firm and interruptible service.

Alliance Canada must comply with all laws and regulations regarding abandonment of the Alliance Canada Pipeline at the end of its economic life. The NEB directed that pipeline companies collect and set aside funds to cover future abandonment costs. Each of Alliance Canada's transportation services includes a pipeline abandonment surcharge designed to collect in aggregate $10.9 million on an annual basis. The collected funds are deposited in an NEB-approved pipeline abandonment trust.

Regulation in the US

Alliance US is subject to regulation by the FERC as a "natural gas company" under the *US Natural Gas Act of 1938*. Under such legislation, the FERC has jurisdiction over Alliance US with respect to virtually all commercial aspects of its business, including transportation of natural gas, rates and charges,

construction of new facilities, extension or abandonment of service and facilities, accounts and records, depreciation and amortization policies, the acquisition and disposition of facilities, the initiation and discontinuation of services, affiliate relationships and certain other matters.

In general, rates charged by interstate natural gas pipeline companies may not exceed the statutory "just and reasonable" or "recourse" rates approved by the FERC and natural gas pipeline companies are prohibited from granting any undue preference to any person or maintaining any unreasonable difference in their rates or terms and conditions of service. However, under the FERC's current policies, a pipeline may obtain approval to charge negotiated rates which differ from (and may exceed) the "just and reasonable" or the FERC regulated "recourse" rate. The FERC approved Alliance US's proposal to offer shippers both negotiated and "recourse" rate options. Accordingly, Alliance US's existing tariff contains both negotiated and "recourse" rates.

Tolls and Tariffs

All of Alliance Canada's transportation shippers pay NEB-approved fixed tolls in accordance with the respective underlying service selection. Seasonal firm service and interruptible shippers pay tolls established through a bidding mechanism.

All of Alliance US's firm transportation shippers have chosen to be governed by fixed negotiated rates under their respective transportation contracts. Interruptible service has been contracted at discounted recourse rates.

All shippers are required to provide fuel in-kind based on an annual fixed fuel rate by service type. The fuel rate will be adjusted annually on an actual tracked basis.

Environmental Matters

Several design features of the Alliance Pipeline make it more efficient than older, conventional natural gas pipelines. However, GHG emissions are created during the combustion of natural gas in turbines that drive compressors to move natural gas through the Alliance Pipeline system. Although GHG emissions have been reduced by using high efficiency gas turbines, the emissions intensity from the Alliance Canada Pipeline still exceeds the net emissions intensity limit calculated under Alberta's *Specified Gas Emitters Regulation* (SGER). Under the SGER, facilities that emit more than 100,000 tonnes of CO_2 annually, which includes the Alliance Canada Pipeline, were required to reduce their emissions intensity commencing in 2009 by 12% of their baseline emissions. Alliance updated its baseline emission intensity in 2014 to reflect improved emission calculation methodologies. This change did not result in a material change in the baseline intensity rate. Given that the Alliance Canada Pipeline is a state-of-the art facility, further emission reductions at the source are difficult and Alliance Canada's remaining compliance options to meet its required emission reduction target are to purchase credits from the Alberta Climate Change Fund for $15.00 per credit (1 credit = 1 tonne of CO_2 emission reductions) or to purchase offsets from qualified projects. The anticipated cost to purchase the necessary credits for 2015 is $1.24 million. The final cost will be determined in the first quarter of 2016.

The Alberta Government announced changes to the SGER program in June 2015. The reduction target remained at 12% in 2015, but will increase to 15% in 2016 and 20% in 2017. The carbon cost will remain at $15/tonne for 2015, but increase to $20/tonne in 2016 and $30/tonne in 2017.

British Columbia implemented the *Carbon Tax Act* in 2008, which taxes the consumption of all fuel sources in the province. Alliance Canada Pipeline's British Columbia operations are subject to this tax

and the cost related to 2015 amounted to $247,000, while for 2016 it is expected to be approximately $373,000.

The cost associated with the credits purchased from the Alberta Climate Change Fund and/or qualified projects, and the British Columbia carbon tax are included in the transportation tolls and recovered from shippers.

In Saskatchewan, the *Management and Reduction of Greenhouse Gases Act* was introduced in the provincial legislature and received Royal Assent on May 20, 2010. This Act, when enacted, will set emission reduction targets for emitters and a carbon compliance payment if the target is not achieved. A clear date for enactment has not been established by the province.

Alliance US is subject to two GHG regulations promulgated by the Environmental Protection Agency. The Mandatory Reporting Rule requires pipeline transmission facilities emitting more than 25,000 metric tons of carbon dioxide equivalent (CO_2e) to report combustion CO_2e emissions annually. Each of the Alliance US compressor stations exceeds this threshold. These facilities were required to add certain fugitive and venting sources of GHG to their emission inventory in 2011. The Tailoring Rule was implemented in a staged fashion in 2011. This regulation requires facilities that emit more than 100,000 short tons of CO_2e to have a Title V Operating permit. This regulation also requires best available control technology considerations for facilities that add 75,000 short tons or more of CO_2e during modifications, or 100,000 short tons or more for construction of new facilities. Each of the Alliance US compressor stations operate under Title V Operating permits.

The operations of Alliance Canada are subject to federal, provincial, and local laws and regulations relating to the protection of the environment. Alliance Canada developed and implemented an environmental management system for operations and maintenance activities relating to the Alliance Canada Pipeline. This environmental management system includes environmental operating practices that ensure proper stewardship of the environment during operations and due consideration of environmental protection during maintenance activities. Alliance Canada believes it has taken adequate measures to mitigate the environmental effects of the operation and maintenance of the Alliance Canada Pipeline. Alliance conducts regular inspections of its facilities, allows pertinent agency inspections as required, and follows defined practices to ensure that regulatory requirements and commitments are met during the construction, operation, and maintenance of its facilities. All prudently incurred costs related to any environmental requirements would normally be expected to be recovered through the transportation tolls.

Operations and Maintenance

The pipe used for the Alliance Pipeline was manufactured using low carbon alloy steel, with controlled rolling practices used to improve strength, ductility, weldability and toughness. All piping and appurtenances were coated externally for corrosion protection and internally to reduce friction. A cathodic protection system was installed to protect against corrosion for the operating life of the Alliance Pipeline.

The Alliance US Pipeline was constructed with characteristics similar to the Alliance Canada Pipeline. However, US regulations call for different requirements in calculating the maximum stress levels compared to Canadian regulations; therefore, the pipe wall thicknesses used in the Alliance US Pipeline are slightly thicker than those used in the Alliance Canada Pipeline.

Alliance Canada and Alliance US employ various operational and maintenance tools and have programs in place including the following:

- Alliance has rigorous integrity management programs and runs in-line inspection tools at regularly scheduled intervals to assess the pipeline for metal loss, deformation, or other anomalies that could affect the long term integrity of the pipeline.

- Alliance patrols and inspects its rights of way, and conducts inspections and audits of all its facilities, including specific items such as cathodic protection, relief valves, and mainline valves.

- Alliance Canada and Alliance US each have agreements with the manufacturers of the mainline compressors on the Alliance Canada Pipeline and the Alliance US Pipeline, respectively, to provide for operational performance support and maintenance services.

- A main control centre and a separate back-up control centre, each located in Alberta with control, alarm and leak detection monitoring capability with remote access and local emergency shutdown capabilities. The control centre continuously monitors pipeline system operation such as gas pressure and temperature and provides for, in conjunction with facility control systems, rapid station shutdown or closure of block valves in the event of an emergency.

- All major compressor station equipment is monitored by the manned system control centre, via on-site control systems that monitor sensors for parameters such as temperature, pressure and vibration. Over the past 4 years replacement control systems have been installed at all compressor units and stations.

- A Process Industrial Control & Operating Environment project, with a mandate to develop and re-engineer an integrated industrial control environment, was initiated in 2012 and completed in 2015. A new SCADA system for data transmission to and from remote facilities and the control centres was fully installed and commissioned in December 2014. Mainline block valves are located approximately every twenty miles, can be remotely operated through satellite communications and are designed to automatically close should there be a sudden pressure drop.

- Alliance's gas management system provides such functions as contract management, customer account management, capacity release, nomination entry, scheduling, confirmation and allocation, imbalance management, invoicing and reporting. On December 1, 2015 Alliance implemented a new gas management system using a third-party product called QPTM to facilitate Alliance's new services.

Pipeline Safety

Natural gas pipelines in Canada are required to meet construction, operating and maintenance standards established by the NEB, other federal regulators and the Canadian Standards Association. Natural gas pipelines in the US are required to meet construction, operation and maintenance regulations established by the US Department of Transportation Pipeline and Hazardous Materials Safety Administration (PHMSA).

The Alliance Canada Pipeline is subject to the *Onshore Pipeline Regulations*, as amended, promulgated pursuant to the NEB Act and *CSA Z662 Oil and Gas Pipeline Systems*. The *Onshore Pipeline*

Regulations concern the design, construction, operation and abandonment of pipelines within the jurisdiction of the NEB. CSA Z662 Oil and Gas Pipeline Systems is a consensus standard administered by the Canadian Standards Association with ongoing participation from regulators, industry, suppliers and engineering consultants. The Alliance Canada Pipeline and its operation comply in all material respects with the NEB Act, the *Onshore Pipeline Regulations* and the requirements of all applicable safety regulations, standards and codes. Alliance Canada has implemented practices and procedures common in the pipeline industry and necessary to meet applicable laws in all material respects.

The Alliance US Pipeline is subject to PHMSA regulations (Title 49, CFR 191, 192 and 199) promulgated under the *US Natural Gas Pipeline Safety Act of 1969*, as amended. Alliance US maintains and follows required plans, procedures and specifications written in compliance with these regulations for the design, construction, operation, maintenance and management of the Alliance US Pipeline, including emergency response, employee qualifications, integrity programs, public awareness programs, control room management programs and drug and alcohol testing.

Alliance has conducted and is expected to continue to conduct the required inspections and audits of items such as cathodic protection, relief valves, mainline valves and patrols of rights of way. Alliance completed a third cycle of in-line inspections of the entire pipeline system in 2015. The frequency of these assessments are based on a detailed evaluation of risk not to exceed maximum intervals established under current US and Canadian regulations and conditions contained within the special permit granted in July 2006 by PHMSA to Alliance US to increase the maximum allowable operating pressure.

The NEB conducted a security assessment of Alliance in late December 2014. Alliance developed a security plan that incorporates corrective actions from the NEB assessment and delivered it to the NEB in early 2016. Additionally, Alliance conducted an internal audit, using the services of a third party auditor, of its security programs. The findings of the audit were delivered in late December, 2015. Alliance is developing a corrective action plan in response to the audit. To bring further alignment with the NEB security assessment, Alliance will be implementing a revised security program integrating physical and cyber security.

As part of its ongoing compliance verification program, the NEB conducted an operational audit of Alliance in 2015. This audit focused on the areas of safety management, environmental protection, emergency management, and third party damage prevention. Interviews and documentation reviews have been completed, and the NEB's audit reports are expected to be released by the end of March 2016. Alliance will then be required to implement corrective actions in relation to any gaps that have been identified. Alliance will prepare and implement a corrective action plan in 2016 to address material issues identified, if any, during the audit.

Alliance conducts routine internal safety and security inspections at its compression facilities, with corrective actions being identified and addressed as appropriate. Alliance conducts ongoing due diligence reviews of its health and safety plans, practices and procedures, using a three year minimum review cycle.

See "*Alliance - Operation and Maintenance*" for further information regarding pipeline safety programs in place.

Outlook

In July 2013, Alliance announced its New Services Framework and advised existing and new shippers that it would proceed with recontracting the pipeline through a Precedent Agreement process. The years 2014 and 2015 represented a transition period with the development, regulatory approval, contracting, and implementation of the proposed new services to replace the contracts that ended on December 1, 2015.

Alliance Canada has recontracted all of its year-round firm receipt capacity through 2018, and approximately 90% of firm receipt capacity in 2019 and 2020, with average contract durations of 5.3 years.

Alliance believes the advantages of the Alliance system include:

- market connectivity;
- competitiveness; and
- design and operational efficiency.

Market Connectivity

The Alliance Canada Pipeline is in close proximity to significant natural gas production areas in northeastern British Columbia and northwestern Alberta, including liquids-rich plays such as the Montney and Duvernay. Production within a 40 km radius of the Alliance Canada Pipeline has grown significantly since 2001, driven by recent rich gas development. Alliance US has two long-term firm transportation contracts from the Bakken region in North Dakota that were renegotiated in late 2015 to conform with Alliance's New Services Framework. A contract with Pecan Pipeline for 92 mmcf/d from the Bantry interconnection with the Prairie Rose pipeline and 71 mmcf/d with Hess on the Tioga Lateral represent the current capacity commitments in the Bakken. If further development of the Bakken area results in increased requests from shippers, the Tioga Lateral and its associated facilities is expandable to provide additional capacity beyond its current design capacity of 126 mmcf/d.

Competitiveness

Alliance provides a unique solution for customers seeking to transport natural gas and entrained natural gas liquids through its New Services Framework for transportation service commencing December 1, 2015. Key attributes of the New Services Framework include predictable and competitive fixed tolls, segmented transportation service that appeals to a diverse range of customers and a new Canadian trading pool. Alliance Canada received approval from the NEB to change the Hydrocarbon Dewpoint gas quality tariff specification from -10 degrees Celsius to -5 degrees Celsius. Similarly, Alliance US received approval from the FERC in 2015 to change the Hydrocarbon Dewpoint gas quality tariff specification from 14 degrees Fahrenheit to 23 degrees Fahrenheit, which was also effective December 1, 2015. Curtailment mechanisms are included in the tariffs to ensure that the pipeline operations and safety are not compromised. The Hydrocarbon Dewpoint specification change will enhance shipper access to rich gas transportation and thus facilitate an increase in the NGL content of the gas Alliance Canada transports. In addition to this Hydrocarbon Dewpoint change, Alliance will also be offering new services to enable shippers to optimize the heat content of their natural gas delivery to Alliance.

Design and Operational Efficiency

A high-pressure pipeline service provides for the dense phase transmission of rich gas, which increases the efficiency of the system. Alliance designed the system with the capability to accommodate higher energy natural gas either at current receipt stations or at new stations with what is expected to be minor system modifications and routine regulatory approvals. This is an advantage in the current environment in which liquids-rich gas drilling is common. The system design provides an alternative for liquids-rich gas shippers looking to avoid building costly field extraction plants.

Alliance expects that the Alliance Pipeline will be utilized beyond 2015 with a portfolio of contracts and services, operating under the new transportation terms and conditions approved by the NEB, given the following:

- the advantages that Alliance can provide in operational efficiency;
- the wide spectrum of operating parameters that the Alliance Pipeline can accommodate to transport gas streams of variable heat content;
- the proximity of the Alliance Pipeline to emerging gas developments; and
- the ability to incorporate new deliveries off the Alliance Pipeline into current or new pipeline systems, hubs and industrial areas.

Competition

The Alliance Pipeline faces competition in pipeline transportation to its Chicago area delivery points from both existing pipelines and proposed projects.

Alliance expects that substantially all of the natural gas shipped on the Alliance Pipeline for the near future will be produced from the WCSB and the Bakken formation. Continued sales of WCSB and Bakken natural gas in the midwestern and northeastern US and eastern Canada will depend on a number of factors over which Alliance has no control, including the:

(a) level of exploration, drilling, reserves and production of WCSB and Bakken natural gas and the price of such natural gas;

(b) accessibility of WCSB and Bakken natural gas, as such may be affected by weather, natural disasters or other impediments to access;

(c) price and quantity of natural gas available from alternative US, Canadian and international sources;

(d) market demand for natural gas in North America;

(e) impact of domestic Canadian demand on the availability of WCSB natural gas for export; and

(f) regulatory environments in the US and Canada, including the continued willingness of both countries to permit the export of natural gas from Canada into the US on a commercially acceptable basis.

A number of other natural gas pipelines currently provide, and potential future natural gas pipelines may provide, transportation services for natural gas produced from the WCSB and the Bakken to natural gas markets in the midwestern US. Such pipelines, existing and proposed, constitute current and potential competitors to the Alliance Pipeline. In addition to the Alliance Pipeline, natural gas from the WCSB is currently transported to markets in the midwestern US through the following pipelines:

- TransCanada/Viking Gas Transmission;
- TransCanada/Great Lakes Gas Transmission; and
- TransCanada/Foothills/Northern Border Pipeline.

Alliance is also exposed to competition from new sources of natural gas, such as the Marcellus Basin which runs from upstate New York to as far south as Virginia. The Marcellus Basin is in close proximity to the Chicago Hub to which the Alliance Pipeline currently provides the majority of its transportation service. The continued development of the Marcellus Basin may provide an alternate source of gas to this location and further decrease natural gas imports from Canada into the northeastern region of the US.

Shippers on the Alliance Pipeline may also elect to access the Ontario market through a combination of the Alliance Pipeline and the pipeline owned by Vector Pipeline L.P. Natural gas from the WCSB is also transported to markets in Ontario via the TransCanada system.

Based on rates currently filed with the respective regulatory authorities, Alliance's rates are competitive in each of the above markets; however, changes to the costs of service of any of these pipelines, or new competition from any future pipeline may affect Alliance's competitiveness.

Any new or upgraded pipelines could offer natural gas transportation services that may be more desirable to shippers than those provided by the Alliance Pipeline because of location, facilities or other factors. In addition, these pipelines could charge rates or provide service to locations that result in greater net profit for shippers, which may result in a decrease to revenues and cash flow for Alliance.

Any project to expand the Alliance Pipeline may be subject to competition from other pipeline systems, which could be expanded or integrated to serve the market for shipping natural gas from the WCSB and/or the Bakken to the midwestern and eastern US and eastern Canada.

During the primary term under the pre-December 2015 transportation contracts on the Alliance Pipeline, the shippers' firm contracted capacity obligations were not affected by a competitive market for natural gas in the midwestern and eastern US and eastern Canada. Under Alliance's New Services Framework, Alliance has firm, take-or-pay contracts in place at volume levels equal to or greater than the volumes under Alliance's original transportation contracts for the next three years. This substantially mitigates any risk from growing competition with US shale production through that timeframe. Alliance does have a portion of capacity above firm contracted levels that is being offered to the market on an interruptible or short-term firm basis. This capacity would be expected to have greater exposure to competition risk than long-term firm.

The Natural Gas Transportation Industry

The natural gas transportation industry from western Canada to eastern markets has historically been controlled by companies affiliated with TransCanada PipeLines Limited. Natural gas supply and pipeline infrastructure has grown over the past several years creating increased competition throughout North America. Production in the US has increased, primarily due to shale gas production, and the lower cost of shale gas has increased competition and created opportunity for customer selection. Production in the mature WCSB has declined in recent years due to reduced drilling activity, although activity remains strong in certain areas of the WCSB. For example, natural gas production in the vicinity of Alliance Canada's receipt infrastructure in the WCSB has grown in recent years.

Ruby Pipeline

Overview

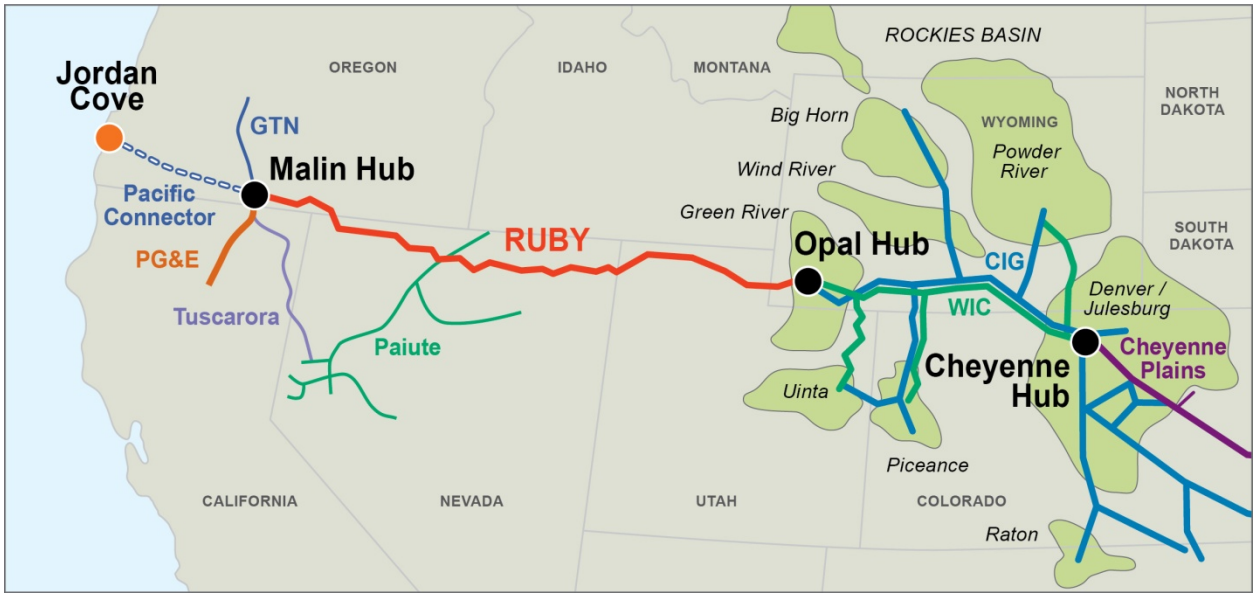
On November 6, 2014, we, through a wholly-owned subsidiary, acquired from GIP, a 50% convertible preferred interest in Ruby Pipeline Holding Company, L.L.C. (Ruby Holdco) for aggregate consideration

of US$1.434 billion. Ruby Holdco, through a wholly-owned subsidiary, Ruby Pipeline, L.L.C. (Ruby Opco), owns the Ruby Pipeline.

The Ruby Pipeline is a newly-built natural gas transmission system delivering US Rockies natural gas production to markets in the western United States. The 680-mile, 42-inch diameter pipeline has a current capacity of approximately 1.5 bcf/d, with four mainline compression stations providing 155,000 hp of compression, and with expansion potential to approximately 2.0 bcf/d, through additional compression.

The Ruby Pipeline was placed in service on July 28, 2011 at a total build cost of approximately US$3.7 billion, including an allowance for funds used during construction.

The Ruby Pipeline originates at the Opal hub in Wyoming and extends to the Malin hub in Oregon. The Malin hub is the main interconnect to the proposed Pacific Connector Gas Pipeline (50% owned by Veresen), which would supply our proposed Jordan Cove LNG terminal. The map below displays the location of the Ruby Pipeline.



The remaining 50% common equity interest in Ruby Holdco is held by EP Ruby LLC, a Delaware limited liability company and an indirect wholly-owned subsidiary of Kinder Morgan Inc. (Kinder Morgan). EP Ruby LLC operates the Ruby Pipeline on a day-to-day basis.

Convertible Preferred Interest

Our Class A preferred units in Ruby Holdco (Ruby Preferred Interest) provide us with an entitlement to preferred distributions of approximately US$91 million annually in priority to payments of distributions on common equity. The Ruby Preferred Interest converts into a common equity interest either at our option or automatically upon the contracting of an additional 250 mmcf/d of long-term firm capacity at rates generally consistent with the current contracts on the Ruby Pipeline. If the Ruby Preferred Interest is converted to common equity, we lose our priority to a fixed level of distributions but would be entitled to a 50% interest of total distributions on common equity.

Each of the holders of the Ruby Preferred Interest and common equity are entitled to appoint a member of Ruby Holdco's Management Committee but voting by such manager is based on the proportionate percentage interest represented by such member (based on units held by that member divided by total

units outstanding, across both classes). Ruby Holdco Management Committee approval is required for material decisions.

Both the holder of the Ruby Preferred Interest and the holder of the common equity interest have certain rights to purchase the other party's interests prior to such interests being offered to third parties.

Shippers on the Ruby Pipeline

Approximately 71% of the capacity of the pipeline (approximately 1.1 bcf/d), is contracted under long-term firm contracts having a weighted average remaining contract term of approximately 7 years. 90% of the contracted volumes (comprised of 61% rated at least A- or its equivalent by either S&P or Moody's and an additional 29% rated at least BBB- or its equivalent by either S&P or Moody's) are with investment grade shippers. Of the remaining 10% of shippers, 8% are rated lower than BBB by S&P and 2% are not rated. Long-term contracted shippers on the Ruby Pipeline include Pacific Gas & Electric Inc., Cascade Natural Gas Corporation, Anadarko Petroleum Corporation, Bill Barrett Corporation, J. Aron & Company, Shell Energy North America (US) L.P., a unit of Royal Dutch PLC, BP Energy Company, Marathon Oil Corp., Pioneer Natural Resources Company, Occidental Petroleum Corporation, Linn Energy, LLC and URSA Operating Company LLC or affiliates of the foregoing.

Expansion and Extension Opportunities

The Ruby Pipeline is designed to be able to cost-effectively increase its capability by approximately 500 mmcf/d by adding compression facilities. Ruby Holdco continues to pursue opportunities to construct or otherwise connect to extensions and laterals as they arise. Expansion or extensions would be subject to regulatory approval and receipt of Ruby Holdco Management Committee approval.

Regulatory Environment

Ruby Opco is subject to regulation by the FERC as a "natural gas company" under the US *Natural Gas Act of 1938*. Under such legislation, the FERC has jurisdiction over Ruby Opco with respect to virtually all commercial aspects of its business, including transportation of natural gas, rates and charges, construction of new facilities, extension or abandonment of service and facilities, accounts and records, depreciation and amortization policies, the acquisition and disposition of facilities, the initiation and discontinuation of services, affiliate relationships and certain other matters.

Tolls and Tariffs

In general, rates charged by interstate natural gas pipeline companies may not exceed the statutory "just and reasonable" or "recourse" rates approved by the FERC, and natural gas pipeline companies are prohibited from granting any undue preference to any shipper or maintaining any unreasonable difference in their rates or terms and conditions of service. However, under the FERC's current policies, a pipeline may obtain approval to charge negotiated rates which differ from (and may exceed) the "just and reasonable" or the FERC regulated "recourse" rate. The FERC has authorized Ruby Opco to offer shippers both negotiated and "recourse" rate options. Virtually all of the Ruby Pipeline's initial shippers chose to be governed by negotiated rates under their respective transportation contracts.

Ruby Opco may file to revise its rates from time to time, however, changes to the recourse rates will not affect the charges under the negotiated rate contracts described above. The FERC also has statutory authority under Section 5 of the US *Natural Gas Act of 1938* to initiate, either on its own motion or upon complaint, an investigation of a pipeline's rates and terms and conditions of service, but rate changes pursuant to a Section 5 proceeding will generally not impact the negotiated rate agreements.

The FERC also has the authority to set maximum permissible rates for the Ruby Pipeline's transportation service (Ruby Recourse Rate). Virtually all of the Ruby Pipeline's currently existing long-term shipper contracts are negotiated rate contracts, which are not subject to any change in rate regardless of the Ruby Recourse Rate set by the FERC. The current maximum Ruby Recourse Rate is US$1.14 per dth/d, which is significantly higher than the highest rate charged under any of the long-term existing shipper contracts. The negotiated rates range from US$0.68/dth to US$0.95/dth depending on the volumes contracted with such shipper. Under the most favored nations clauses in the negotiated rate contracts, any new long-term firm shipper must pay a rate that is greater than or equal to the rates for existing shippers in the same volumetric class or all of the existing negotiated rates for such class must be reduced.

In July 2014, Ruby made a cost and revenue study filing with FERC. On November 5, 2014 FERC accepted the study and did not propose any changes to the current Ruby Recourse Rate. On February 1, 2016, Ruby submitted a tariff compliance filing with FERC for order 587-W relating to standards intended to harmonize gas-electric scheduling coordination and revisions regarding certain postings requirements for offers to purchase released capacity.

Environmental Matters

Since inception, the Ruby Pipeline has not received any material environmental citations, notice of violations or any fines or penalties. The Ruby Pipeline is the first "Carbon-Neutral" interstate natural gas pipeline in the US mitigating all GHG emissions in its construction and operation through the purchase of carbon offsets. The Ruby Pipeline's tariff provides that shippers reimburse the cost of acquiring the offsets, which is collected through the electric power cost charge.

All material Ruby Pipeline permits are in full effect with no outstanding material issues.

Operations and Maintenance

Day-to-day operations of the Ruby Pipeline are undertaken by EP Ruby, LLC, which utilizes the services of affiliated subsidiaries of Kinder Morgan, that specializes in field operations, field measurement, field corrosion, field mechanical, environmental, health and safety and engineering and technical services, among other areas.

The operations and maintenance team utilize a number of best-in-class systems in operating the Ruby Pipeline. The team recently completed the implementation of a system which enables customers to interface with the pipeline, schedule receipts, schedule deliveries, and monitor capacity constraints. Additionally, Kinder Morgan's robust maintenance process is supplemented by its maintenance management systems.

Pipeline Safety

With an in-service date of July 28, 2011, Ruby Pipeline is a relatively new pipeline. Natural gas pipelines in the US are required to meet construction, operation and maintenance regulations established by the US Department of Transportation PHMSA office of Pipeline Safety.

The Ruby Pipeline is subject to PHMSA regulations (Title 49, CFR 191, 192 and 199) promulgated under the US *Natural Gas Pipeline Safety Act of 1969*, as amended. The Ruby Pipeline maintains and follows required plans, procedures and specifications written in compliance with these regulations for the design, construction, operation, maintenance and management of the Ruby Pipeline, including emergency response, employee qualifications, integrity programs, public awareness programs, control room management programs, and drug and alcohol testing.

Outlook

Market Connectivity

The Ruby Pipeline originates close to significant natural gas production areas in liquids-rich and associated natural gas resources in the Rockies regions of Wyoming, Utah and Colorado and supplies California, the Pacific Northwest (including Oregon and Washington), and Northern Nevada markets. Ruby's end-user markets have little indigenous natural gas production.

Competitiveness

The Ruby Pipeline competes to deliver gas into the western US primarily with western Canadian gas delivered through the TransCanada/Gas Transmission Northwest pipeline system and, to a lesser extent, with Rockies gas delivered through Northwest Pipeline. The Ruby Pipeline provides an important source of supply diversification for customers in the Pacific Northwest and northern California who would otherwise be largely reliant on Canadian supply.

The Ruby Pipeline competes to export gas from the Rockies with several pipelines, including Northwest Pipeline into the Pacific Northwest, the Kern River pipeline into California, and numerous pipeline systems (including the Rockies Express and Trailblazer pipelines and several affiliated Kinder Morgan pipeline systems) that can transport gas into the eastern and Midwestern US. Growing gas production from prolific shale basins in the northeastern US has negatively affected eastern exports of Rockies gas in recent years relative to western exports on pipelines, including the Ruby Pipeline.

During the primary term under the transportation contracts on the Ruby Pipeline, the shippers' obligations to pay the monthly fixed reservation rates for their contracted capacity are firm and are not affected by a competitive market for natural gas in the Rockies and western US. Prior to the expiry of the primary term, the Ruby Pipeline will need to negotiate and enter into new transportation contracts.

Design and Operational Efficiency

As a highly efficient, recently constructed pipeline, Ruby Pipeline reduces constraints on takeaway capacity and represents the most direct and cost effective route for natural gas to be transported from the Rockies to Western US markets. Furthermore, the Ruby Pipeline's capacity can be expanded by 500 mdth/d through additional compression only, hence at low cost compared to greenfield projects.

Alberta Ethane Gathering System

Overview

AEGS transports purity ethane within Alberta from various ethane extraction plants to major petrochemical complexes located near Joffre and Fort Saskatchewan, Alberta. At 1,336 km in total length, AEGS is comprised of separate legs that form an integrated system which includes interconnections with an underground storage site in Fort Saskatchewan.

Shipper Profile and Ethane Transportation Agreements

The AEGS shipper community is currently comprised of NOVA Chemicals Corporation (NOVA), Dow Chemical Canada ULC (Dow), Plains Midstream Canada (Plains) and Shell Chemicals Canada. Each of these shippers is either a major ethane producer or consumer and all have substantive energy infrastructure and/or petrochemical investments in Alberta. Each shipper is party to a long-term take-or-

pay ethane transportation agreement extending to December 31, 2018. The transportation agreements provide for:

- a minimum revenue stream to AEGS based on specified committed volumes;
- the recovery of all operating costs;
- the right for each shipper to transport ethane on AEGS up to their committed volume limits;
- limited rights in favour of the shipper for toll relief in the event AEGS is unable to transport volumes of ethane up to the shipper's contracted capacity; and
- the right to terminate the transportation agreement in certain circumstances where the shipper is unable to transport ethane on AEGS for a period of 180 days or more.

AEGS also holds a contract with the Plains-operated Fort Saskatchewan Storage Joint Venture for the storage of ethane in underground caverns located near Fort Saskatchewan, Alberta.

Ethane Customers

AEGS delivers the majority of the ethane feedstock requirements for NOVA's ethylene facilities located near Joffre, Alberta. These facilities comprise one of the largest ethylene and polyethylene complexes in the world. Ethane is also transported to Dow's ethylene facilities located near Fort Saskatchewan, Alberta and to Dow's facilities located near Joffre. Correspondingly, AEGS remains one of the primary means of transporting ethane feedstocks to the Alberta markets.

Operations and Maintenance

We have an operating agreement with NOVA whereby NOVA is responsible for the safe field operations of AEGS. NOVA's responsibilities under the operating agreement include:

- maintaining the AEGS asset in the field;
- obtaining and managing all operational personnel in the field;
- obtaining and maintaining all regulatory authorizations required for operation; and
- maintaining operating cost records.

We remain responsible for commercial operations in respect of AEGS, including:

- receiving and scheduling nominations from shippers;
- invoicing shippers;
- approving facility outages schedules and annual operating cost budgets;
- informing shippers of issues, facts and circumstances affecting AEGS;
- resolving disputes with shippers; and

- entering into, renewing or amending contracts with shippers, including the ethane transportation agreements.

The operating agreement will remain in effect until terminated in accordance with its terms. Reasons for termination include:

- permanent cessation of operations of AEGS;
- insolvency of either party;
- default by either party in performing any of its material obligations where such default is not caused by the party seeking termination and the default causes or is likely to cause a material adverse change in the party seeking termination (subject to a cure period);
- operator providing 12 months' notice of its intent to resign as operator; and
- in certain circumstances, us providing 12 months' notice of our intent to assume operation of AEGS.

Regulatory Environment

AEGS is licensed under the jurisdiction of the Alberta Energy Regulator. As a contract carrier, rather than a regulated common carrier, AEGS' tolls are not subject to regular review by the Alberta Energy Regulator.

Environmental Matters

All pump stations on AEGS utilize electrically driven pumps. Accordingly, no air permits or air monitoring is required for any rights of way or pump station locations, and no routine emissions reports are required.

AEGS utilizes waste management services to ensure proper classification and disposal of waste generated at its facilities. Provincial regulations, including those for waste tracking and manifesting, are the principles employed for waste management. There are no waste management facilities maintained by AEGS. Pipeline filters at pump stations remove particles, including naturally occurring radioactive materials from the ethane stream. These filters are the principal waste generated by AEGS. Procedures are in place to safely change these filters and temporarily store them on site. Each pump station has small, dedicated storage sheds to provide temporary storage for these filters prior to processing and disposal.

No water discharge permits are required for operations along AEGS and groundwater is not required at any of the rights of way or pump station locations on AEGS.

Outlook

We will continue to focus on maintaining high levels of operational stability and efficiency. In addition, we continue to evaluate pipeline infrastructure opportunities specific to AEGS.

Competition

During 2015, AEGS continued to transport the majority of ethane extracted in or imported into Alberta. As AEGS is currently connected to most of the major sources and users of ethane, at this time there are no known viable, lower-cost alternatives that could reasonably compete for this business.

The Specification Ethane Transportation Industry

Ethane occurs normally as a constituent of natural gas. As with other components of NGL, ethane is in gaseous form at the pressures and temperatures under which natural gas is typically gathered and transported. When natural gas is processed at efficient field gas plants or at large straddle plants ethane is separated and recovered in liquid form. Natural gas value is enhanced by extracting ethane and other NGL, which have historically had a higher value as specification products than when retained in the natural gas stream.

Ethane Market Structure

The western Canadian ethane market is characterized by a small number of product suppliers. The suppliers are the owners of the straddle plants and extraction facilities. There are a smaller number of purchasers which are primarily the major petrochemical producers. The Alberta ethane market is to a large extent insulated from the supply and demand forces of the substantially larger US market as most of the ethane production is contracted under long-term agreements, under which purchase prices often reflect supply costs.

Current Ethane Supply

Ethane supply in Alberta is a function of a number of factors, including:

- gas production rates in the WCSB;
- the percentage of gas processed in the region (as compared to the percentage that bypasses straddle plants or is exported via the Alliance Pipeline);
- the average ethane content of raw gas produced;
- the ethane extraction efficiency and capacity of facilities within Alberta; and
- the ethane demand market within Alberta.

In recent years, the interaction of these forces has resulted in ethane supply declines in western Canada. These declines were largely due to shifting supply and demand dynamics in North American natural gas markets. The resulting lower raw gas flows past Alberta's extraction plants has had a direct correlation to lower ethane production levels. However, these declines have been mitigated by recent supply additions from field plants in Alberta and also imports from North Dakota.

Current Ethane Demand

Ethane is used as a feedstock for ethylene production. In turn, the ethylene produced in Alberta is used as a feedstock for polyethylene production. Ethane consumption in Alberta has historically matched available supply. The majority of ethane is consumed by the major ethylene petrochemical facilities at Joffre and Fort Saskatchewan.

Ethylene plant operating rates, which are a function of ethylene demand, are determined by the relative cost competitiveness between ethylene producers in Alberta and their global competitors. Thus, subject to any government changes in the ethane industry and provided Alberta's petrochemical industry remains competitive globally, the current demand for ethane in Alberta's ethylene plants is anticipated to remain reasonably stable for the near-term and potentially increase over the long-term.

OUR MIDSTREAM BUSINESS

Map of Our Midstream Business

Overview of Our Midstream Business

Our Midstream Business is comprised of:

(a) assets we jointly control through our 49% interest in Veresen Midstream. The Veresen Midstream assets are all located in northwest Alberta and northeast British Columbia and service the Encana/CRP Montney development and existing Cadomin and Doig production. These assets include:

  (i) the Hythe/Steeprock natural gas gathering and processing complex with a combined functional capacity of 516 mmcf/d;

  (ii) approximately 900 km of gas gathering lines and 1,415 mmcf/d of gas compression; and

  (iii) three gas plants under construction, being the 400 mmcf/d Sunrise gas plant, the 200 mmcf/d Tower rich gas complex and the 400 mmcf/d Saturn gas plant;

(b) assets we jointly control through our 42.698% interest in Aux Sable US and Alliance Canada Marketing including:

  (i) a world-class NGL extraction and fractionation facility located at Channahon, Illinois, capable of processing up to 2.1 bcf/d of natural gas and recovering up to 107,000 bbls/d of NGL consisting of ethane, propane, normal butane, iso-butane and natural gasoline;

  (ii) distribution facilities downstream of the Channahon facility including NGL storage, rail loading, truck loading and pipelines;

  (iii) the Palermo Conditioning Plant, the Prairie Rose Pipeline and the Tioga propane injection facility located in the Bakken region of North Dakota; and

  (iv) long-term contracts for 76.2 mmcf/d of firm transportation capacity on the Alliance Pipeline held by Alliance Canada Marketing;

(c) assets we jointly control through our 50% interest in Aux Sable Canada, including:

  (i) 22% ownership of the 75 mmcf/d Septimus Gas Plant near Fort St. John, British Columbia and full ownership of the Septimus Gas Pipeline, a 20-inch diameter, 20-km pipeline connecting gas from the Septimus Gas Plant to the Alliance Pipeline;

  (ii) 22% ownership of the 60 mmcf/d Wilder Gas Plant near Fort St. John, British Columbia;

  (iii) a commercial business to attract NGL rich gas to the Alliance Pipeline for processing at the Channahon facility;

  (iv) the Heartland off-gas facility with a long-term off-gas processing agreement with Shell to process up to 20 mmcf/d of off-gas and produce methane, hydrogen, ethane and a propane-plus mix, delivered by pipeline to Shell; and

  (v) the development of off-gas processing opportunities in Alberta.

Veresen Midstream Assets

Veresen Midstream owns gas gathering pipelines, compression and gas plants in northeastern Alberta and northwestern British Columbia. These assets include approximately 900 km of pipelines, 1,415 mmcf/d of compression and 516 mmcf/d of gas processing capacity.

Formation of Veresen Midstream

On April 1, 2015, we completed the formation of Veresen Midstream, which is owned by a wholly-owned subsidiary of ours and affiliates of Kohlberg Kravis Roberts & Co. L.P. (KKR), a global investment firm.

We funded our interest in Veresen Midstream by contributing our Hythe/Steeprock gas 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. Concurrently, Veresen Midstream acquired certain natural gas gathering and compression assets supporting Montney development in the Dawson region of northeast British Columbia from the Encana Corporation (Encana) and the Cutbank Ridge Partnership (CRP), a partnership between Encana and Cutbank Dawson Gas Resources Ltd., subsidiary of Mitsubishi Corporation. 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. The acquisition was funded through a combination of cash provided by KKR and a newly established credit facility.

Veresen Midstream Structure and Financing

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 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 either at KKR's or Veresen's option. Future equity contributions in Veresen Midstream will be funded by the partners in cash-paying units on a pro-rata basis. We and KKR have equal governance rights in Veresen Midstream so long as either partner's equity interest remains above 35%.

Upon closing of its formation, Veresen Midstream entered into a US$575 million Term Loan B which was drawn on closing to fund a portion of the initial acquisition consideration, a $1.275 billion non-revolving expansion facility to fund construction capital and a $75 million revolving credit facility which is available for operating and working capital requirements. Veresen Midstream plans on funding approximately 55% to 60% of its growth program with debt and the remainder with equity contributions from us and KKR.

Dawson Acquisition

Veresen Midstream completed the acquisition of the Dawson infrastructure assets from Encana and CRP effective April 1, 2015. This infrastructure included approximately 500 km of gas gathering pipelines and 675 mmcf/d of compression capacity along with the 200 mmcf/d Saturn compressor station which was nearing construction completion. The Dawson acquisition also included the construction work in progress at the 400 mmcf/d Sunrise and 200 mmcf/d Tower gas plants. Construction on those facilities began in 2015 and both are expected to be in service late 2017. Beyond Sunrise and Tower, CRP has also sanctioned the Saturn compression station expansion, Saturn Phase 2, which will add an incremental 200 mmcf/d of compression and 400 mmcf/d of processing capacity to the Saturn compressor site, converting

this site into a 400 mmcf/d gas plant. The Dawson infrastructure gathers Encana and CRP's Montney gas production in the region and delivers it to downstream gas pipelines and processing facilities.

Veresen Midstream and Encana/CRP entered into a Midstream Services Agreement (Dawson MSA) with respect to the new acquired infrastructure and future infrastructure to be constructed within a large Area of Mutual Interest (AMI) of approximately 240,000 acres of Montney rights, which encompasses Encana and CRP's Dawson South, Dawson North and Tower plays. The Dawson MSA provides Veresen Midstream with an attractive expected return on all invested capital, including the initial acquisition and new infrastructure to be built, through a 30 year, fee-for-service arrangement. Commercial terms include a production dedication to Veresen Midstream's gathering system for all of Encana and CRP's Montney natural gas production within a large AMI.

In addition, Veresen Midstream committed to fund up to $5 billion of new infrastructure within the AMI to service CRP's planned production growth, including gas gathering pipelines, compression and processing facilities. These new investments are underpinned by the Dawson MSA and are limited to projects that commence by the end of March 2021.

Encana will manage the construction of new infrastructure within the AMI and will operate the gathering pipelines and compression and processing facilities on behalf of Veresen Midstream on a contracted basis. Veresen Midstream will assume operatorship of processing facilities at its option after an interim operating period. Veresen Midstream retains the flexibility to increase the capacity for new facilities in order to service third party gas volumes.

Hythe/Steeprock Complex

The Hythe/Steeprock complex is located approximately 30 km southeast of the Dawson assets in northwest Alberta and northeast British Columbia. Natural gas and NGL in the Cutbank Ridge region are produced from the Montney, Cadomin and other geological formations. The Hythe/Steeprock complex and related assets and agreements were acquired by Veresen in 2012 and assigned to Veresen Midstream at the closing of the Veresen Midstream Transaction.

The Hythe/Steeprock complex includes two natural gas processing plants, the Hythe plant and the Steeprock plant, with combined functional capacity of 516 mmcf/d as well as approximately 570 mmcf/d of compression and 370 km of gas gathering lines. The Hythe plant processes both sour and sweet natural gas, while the Steeprock plant is a sour gas processing facility. The Hythe facility is undergoing a 50 mmcf/d refrigeration expansion that is expected to be in service in the fall of 2016.

Veresen Midstream has a Midstream Services Agreement (Hythe/Steeprock MSA) with Encana through 2032. The Hythe/Steeprock MSA provides for minimum monthly fees based on specific committed volumes and unit fees (take-or-pay), 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.

Actual monthly volumes delivered by Encana vary relative to the minimum volume commitments set out in the Hythe/Steeprock MSA. The Hythe/Steeprock MSA provides a mechanism whereby limited excess or deficiency volumes can be carried forward for a rolling 12-month period and credited towards any changes resulting from deliveries in deficiency or excess for the minimum volume commitment. Cumulative excess volumes from the previous 12-month period can be used towards the current month's fees to the extent Encana is using less than the committed volumes in the current month. Conversely, cumulative deficiency volumes from the previous 12-month period can be used to offset the current

month's excess volumes. The credits that can be carried forward are subject to financial limits. No carry-forward scenarios will result in us receiving less than the minimum committed fees.

Operations and Maintenance

Veresen Midstream is the operator of record for all of its facilities, including the Dawson and Hythe/Steeprock gathering, compression and processing facilities. In the case of the Hythe/Steeprock facilities, we and Veresen Midstream have had an excellent track record of safe and highly reliable operations since transition from Encana in June 2012. Encana is contract operator of all gathering and compression assets in Dawson. These assets also have a strong operational track record.

Aux Sable Assets

The NGL produced by Aux Sable is an integral component of numerous products used directly as energy products (including home and industrial heating, crop drying, cooking, and motor fuel). NGL is also used as feedstock for the petrochemical industry (for the production of ethylene, propylene, butadiene and other derivatives, which are used to produce products such as polyethylene, rubber, plastics, solvents, and foam materials) and crude oil refining (for gasoline and gasoline blending). Overall, economic activity and weather conditions provide strong influences on the demand for NGL. Crude oil and natural gas prices, commodity inventory positions as well as seasonal factors strongly influence midstream margins.

Channahon Facility

The Alliance Pipeline transports rich gas to Chicago, including any NGL injected at the NGL injection facilities. NGL is extracted from the rich gas at the Channahon facility. The NGL extracted by the Channahon facility is separated at the downstream facilities into ethane, propane, normal butane, iso-butane and pentanes plus. Aux Sable Liquid Products LP sells NGL production at the Channahon facility to BP Canada Products North America, Inc. (BP Canada), and affiliates thereof, pursuant to a long-term NGL sales agreement described below.

The Channahon facility manages the higher heat content levels associated with the rich gas flowing in the Alliance Pipeline in order to meet downstream pipeline heat content requirements. The facility is strategically located in Channahon, Illinois at the terminus of the Alliance Pipeline and close to major markets that are frequently NGL supply-constrained in the first and fourth quarters of each year. Aux Sable is a significant supplier of propane and ethane to the midwestern US, particularly in Illinois and its neighbouring states.

The Channahon facility is capable of processing the peak day volumes delivered by the Alliance US Pipeline and extracting liquid hydrocarbons present in the gas stream. With only one of its two trains operating, the Channahon facility is capable of processing sufficient volumes for the Alliance US Pipeline to meet the maximum heat content requirements of the downstream pipelines.

We and the other owners have approved a US$130 million project to increase fractionation capacity of the Channahon extraction and fractionation facilities by approximately 24,500 bpd to 131,500 bpd. This fractionation expansion will increase propane and butane processing capacity and has a target in-service date of mid-2016.

Aux Sable Liquid Products LP has the exclusive right to extract NGL from natural gas transported on the Alliance Pipeline at the point of its interconnection with the Channahon facility. Aux Sable Liquid Products LP has an obligation to compensate shippers for any NGL so extracted by replacing such NGL with "make-up" natural gas having a heat content equal to the heat content removed due to the extraction

of such NGL. Under the NGL sales agreement, BP Canada supplies to the Channahon facility, at an agreed upon indexed price, all net make-up and fuel natural gas.

In connection with these extraction agreements, Aux Sable US and Alliance US entered into a heat content management agreement, and Aux Sable Extraction LP entered into an interconnection agreement, with Alliance US. Under the heat content management agreement, Aux Sable Extraction LP provides heat content management services. This involves extracting NGL to the extent required to reduce the gross heating value of the natural gas delivered out of the Alliance US Pipeline downstream of the Channahon facility. Aux Sable US will reduce the heating value to a level acceptable to the two local natural gas distribution systems and the five interstate natural gas pipeline companies, following the FERC guidelines. Alliance US has delivery interconnection agreements with these seven systems and companies. Although the heat content management services are provided primarily through the extraction of NGL, Aux Sable Extraction LP has the option to implement alternative heat content reduction arrangements. During 2004, the heat content requirement with one downstream interconnection was amended to give Aux Sable increased operating flexibility. The heat content management agreement has a term of 25 years which commenced on December 1, 2000, subject to any earlier termination of Aux Sable Liquid Products LP's extraction rights.

Subject to any contrary directive issued by any regulatory or other public authority, Alliance US has covenanted to the shippers on Alliance Pipeline not to:

(a) consent to any amendment or early termination of the heat content management agreement;

(b) jeopardize the heat content management agreement or the performance of Aux Sable Extraction LP's obligations thereunder; or

(c) waive or otherwise fail to enforce any of Aux Sable Extraction LP's obligations or Alliance US's rights under the heat content management agreement.

Any breach of this covenant by Alliance US which results in interruption or curtailment of transportation service on the Alliance Pipeline could result in reimbursements or credits payable by Alliance US for reservation or demand charges paid or payable by the shippers to Alliance for the unavailable transportation service on the Alliance Pipeline.

Rich Gas Premium Agreements

Aux Sable Canada has entered into tailored commercial agreements with rich gas producers in the Montney and Duvernay areas of Alberta and British Columbia representing multi-year commitments of rich gas supply to the Channahon facility (RGP Agreements). The term of many of the RGP Agreements extend beyond December 2015. These RGP Agreements, in combination with US deliveries onto Alliance Pipeline, are expected to result in the transportation of up to 1.2 bcf/d of rich gas on the Alliance Pipeline to Aux Sable's Channahon facility.

Aux Sable Canada has gas positions in multiple locations on the Alliance Pipeline in Canada as a result of the RGP Agreements. In conjunction with its RGP Agreement contracting, Aux Sable has developed natural 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, while seeking to mitigate exposure to commodity prices or basis differentials.

NGL Sales Agreement

Aux Sable Liquid Products LP and BP Canada entered into an NGL sales agreement dated effective December 31, 2005, pursuant to which Aux Sable Liquid Products LP sells all of its NGL production at the Channahon facility to BP Canada. In return, BP Canada pays Aux Sable Liquid Products LP a fixed annual fee and a percentage share of any net margin generated from the business in excess of specified thresholds. In addition, BP Canada compensates Aux Sable Liquid Products LP for all operating, maintenance and capital costs associated with the Channahon facility, subject to certain limits in the case of capital costs. The NGL sales agreement has an initial term expiring March 31, 2026, and may be extended by mutual agreement for 10-year terms on a continuous basis. BP Canada has the option to terminate the NGL sales agreement if cumulative losses from the business exceed a specified amount, however, Aux Sable Liquid Products LP retains the right to reduce such losses and thereby avoid termination. The NGL sales agreement provides greater stability to the earnings stream of Aux Sable Liquid Products LP.

The cash flow generated from Aux Sable will vary primarily according to changes in the difference between its supply costs and the sale price of its products. The supply costs consist largely of the cost to purchase shrinkage make-up gas.

Downstream Facilities

Aux Sable Liquid Products LP and Aux Sable Midstream own and operate certain downstream facilities to further process the ethane plus output from the Channahon facility. These downstream facilities include:

- fractionation facilities to separate the ethane plus into its constituents (being ethane, propane, normal butane, iso-butane and pentanes plus);
- approximately 200,000 bbls of onsite storage;
- pumping facilities to deliver the NGL to downstream pipelines for distribution in the midwestern US;
- truck and rail car loading facilities;
- a rail storage yard with a capacity to store 150 railcars; and
- pipelines to transport products downstream of the Channahon facility.

Firm Transportation Contracts and Injection Facilities

Alliance Canada Marketing holds total firm transportation capacity of 76.2 mmcf/d on the Alliance Pipeline for the purposes of optimizing the capacity of the Alliance Pipeline and assisting in the delivery of make-up gas to meet the make-up gas obligations of Aux Sable. As a shipper on the Alliance Pipeline, Alliance Canada Marketing is entitled to the relevant capacity and is obligated to pay the associated demand charges. Arrangements have been made whereby each of the partners in Alliance Canada Marketing has committed to provide its *pro rat*a share of any revenue shortfalls in such partnership and to provide Alliance with security for its demand charge obligations under such transportation contracts in accordance with the terms and conditions of the relevant tolls and tariffs. Each partner therein, including us, has provided appropriate guarantees or letters of credit as its *pro rata* share of such security.

Pursuant to the NGL sales agreement, Alliance Canada Marketing has assigned to BP Canada the capacity in Canada it holds on the Alliance Canada Pipeline. BP Canada has agreed to pay market rates to use this

capacity in Canada. Alliance Canada Marketing has appointed BP Canada as agent in the US for the Alliance US Pipeline capacity, for which capacity Alliance Canada Marketing pays in the US. BP Canada has agreed to pay market rates to use this capacity. BP Canada uses the capacity to provide transportation of rich gas and injected NGL for use and processing at Aux Sable's facilities.

With the assignment to BP Canada, Aux Sable Liquid Products LP does not have direct responsibilities for the firm transportation contracts held by Alliance Canada Marketing and is not considered to have any marketing function employees under the FERC guidelines. Alliance Canada Marketing and BP Canada manage the firm transportation contracts held by Alliance Canada Marketing. Enbridge manages Alliance Canada Marketing on behalf of the owners of Alliance Canada Marketing.

Heartland Off-Gas Processing Facility

Aux Sable Canada has a long-term off-gas processing agreement with Shell as a feedstock source for its wholly-owned Heartland off-gas facility. The facility processes up to 20 mmcf/d of off-gas and produces hydrogen, ethane and a propane-plus mix. All products produced from the facility are delivered to Shell, except ethane, which is delivered to AEGS.

The business premise of off-gas processing is that the potential NGL components in the produced off-gas from a refiner/upgrader have a value greater than their inherent energy value. The products produced contain both paraffins (ethane, propane, butane and heavier products) and olefins (ethylene, propylene, butylenes and other similar products), with the compositions varying with the type of refinery or upgrading technology supplying the off-gas.

Septimus and Wilder Gas Plants

In December 2009 Aux Sable Canada purchased from Crew, at the cost of construction, the 25 mmcf/d Septimus Gas Plant in the liquids-rich Montney region of northeast British Columbia. Crew operates the facility and pays Aux Sable Canada capital throughput fees on a take-or-pay basis.

A 20-inch diameter, 20-km pipeline connecting the Septimus Gas Plant to the Alliance Pipeline was constructed by Aux Sable Canada and placed into service during 2010. The facility was expanded effective February 2011, increasing the plant's licensed processing capacity to up to 60 mmcf/d. In April 2014, the plant's processing capability was further increased to 75 mmcf/d.

Crew exercised its option to repurchase 50% of the Septimus Gas Plant which repurchase became effective on January 24, 2014. Effective November 5, 2014, Aux Sable Canada agreed to convert its 50% interest in the Septimus Gas Plant to an estimated 22% interest in each of the Septimus Gas Plant and the Wilder Gas Plant (a new gas plant designed for 60 mmcf/d being constructed by Crew in the same vicinity as the Septimus Gas Plant). This conversion was completed by way of an exchange agreement dated October 1, 2015.

Palermo Conditioning Plant and Prairie Rose Pipeline

Aux Sable Midstream's Palermo Conditioning Plant has a capacity of 80 mmcf/d. The Prairie Rose Pipeline connects the Palermo Conditioning Plant to the Alliance Pipeline, which delivers rich gas to Aux Sable's Channahon facility for processing. Both the plant and the pipeline were acquired by Aux Sable Midstream in July 2011, commenced operation in February 2010 and are operated by Aux Sable Midstream. The plant removes the heavier hydrocarbon compounds while leaving the majority of the NGL in the rich gas delivered into the Prairie Rose Pipeline. In July 2012 Aux Sable Midstream constructed and commissioned an NGL mix truck unloading facility at the plant with initial capacity of

5,000 bbls/d. In April 2014, Aux Sable commissioned a 7,500 bpd propane injection facility at Tioga. The facility injects propane from Hess into the Alliance Pipeline Tioga Lateral.

The 12-inch diameter, 83-mile Prairie Rose Pipeline gathers gas from the Palermo Conditioning Plant and other sources for delivery into the Alliance Pipeline system at Bantry, North Dakota. The pipeline has an estimated capacity of 120 mmcf/d and can be expanded to meet additional demand.

Environmental Matters

The Veresen Midstream assets, including the Hythe/Steeprock gas processing facilities, are subject to stringent regulatory and environmental requirements. The Hythe/Steeprock facilities are managed under our Environmental, Health and Safety (EHS) Program, which incorporates overarching directives and facility specific procedures to manage our facilities' significant environmental aspects and resulting impacts. See "*Environmental, Health and Safety Program*". Each of the facilities comprising the Hythe/Steeprock complex is subject to its respective provincial GHG annual reporting requirements. As the Hythe facility currently emits less than 100,000 tonnes of CO_2 annually, it is not considered a Large Final Emitter under Alberta's SGER and therefore is not subject to GHG reduction program requirements. Combustion of natural gas to provide heat to the processing facility at Steeprock is subject to British Columbia's Carbon Tax and comply with all such requirements.

As contract operator of the Dawson gathering and compression assets, Encana manages environmental matters through their comprehensive program. Veresen Midstream, in an assurance role, has a close working relationship with Encana.

Construction of Aux Sable's Channahon facility was completed in 2000 and used design criteria based on meeting the applicable US *Environmental Protection Act* standards. Facility inspections are conducted as required by regulation and any deficiencies are remediated prior to recommissioning of the applicable facilities.

In September 2014, Aux Sable Liquid Products L.P. received a Notice of Violation (NOV) from the United States Environmental Protection Agency (USEPA) for alleged violations of the *Clean Air Act* related to the Leak Detection and Repair program, and related provisions of the *Clean Air Act* permit for the Channahon facility. As part of the ongoing process of responding to the NOV, Aux Sable discovered what it believes to be additional exceedance of currently permitted limits for Volatile Organic Material. Aux Sable is engaged in discussions with the USEPA to evaluate the potential impact and ultimate resolution of these issues.

Safety

We have a comprehensive EHS Program which has been integrated into the Veresen Midstream operations. Leveraging the existing Hythe/Steeprock systems at the time of our acquisition and combining those with our EHS Program, including the use of the SMART system for incident management, provides our operating facilities with a strong basis to ensure protection of human health and safety. These Hythe/Steeprock facilities have a strong culture of positive observation, hazard identification and near-miss reporting, with 445 entries into the SMART system in 2015.

As contract operator of the Dawson gathering and compression assets, Encana manages EHS through their comprehensive program. Veresen Midstream has a close working relationship with Encana.

Aux Sable continues to place a top priority on safety in terms of workforce training, facility design and the operation of its facilities. Aux Sable strives to meet or exceed all applicable laws and regulatory

requirements, including a strong focus on Process Safety Management, annual risk assessments and a commitment to safety at all levels in the organization. Aux Sable experienced no lost time injuries in 2015.

Outlook

Veresen Midstream committed to fund up to $5 billion in new infrastructure within the AMI for projects initiated by the end of March 2021, including the assets acquired and construction in-progress. In October 2015 CRP sanctioned the Sunrise Gas Plant, a 400 mmcf/d gas facility servicing Montney production in the region near Dawson Creek in northeastern British Columbia. Construction of the Sunrise Gas Plant commenced in 2015, with an estimated capital cost of $860 million and the facility is expected to be in service in late 2017.

In December 2015 CRP sanctioned the Tower rich gas processing complex, a 200 mmcf/d, 20,000 bbls/d condensate and NGL facility servicing Montney production in the region south of Fort St. John in northeastern British Columbia. The estimated capital cost for the project is $715 million, construction was commenced in 2015 and the facility is expected to be in service in late 2017.

To continue to service CRP's growth profile CRP sanctioned Saturn Phase 2 to add an incremental 200 mmcf/d of compression and 400 mmcf/d of processing capacity to the Saturn compressor site. The end result will be a 400 mmcf/d gas plant at Saturn. Saturn Phase 2 is expected to be in service in mid-2018.

CRP continues to evaluate new infrastructure needs and it is anticipated that they will continue to sanction new projects which will be funded by Veresen Midstream. The timing and scale of these new projects is uncertain but there remains approximately $2 billion of capital available under the previously mentioned commitment to fund up to $5 billion of new projects in the AMI.

Veresen Midstream continues to seek out and evaluate other midstream opportunities outside of the AMI. This includes pursuing several growth opportunities around increased processing capacity at the existing and under construction facilities as well as a number of other initiates in other geographic regions of Northeastern British Columbia and the Deep Basin in Alberta.

Aux Sable is well positioned with operational and commercial capability to pursue additional investment opportunities (largely on a fee-for-service basis), including those leveraged off of the rich gas stream flowing on the Alliance Pipeline.

In western Canada, Aux Sable Canada primarily focuses on increasing rich gas deliveries into the Alliance Pipeline. Developments to optimize existing gas supply and connect new sources of rich gas supply have been expanded to include British Columbia based on the new rich shale gas developments in this region. Aux Sable Canada's activity in the Septimus area of northeast British Columbia is one component of this strategy. Aux Sable Canada provides processing and transportation alternatives for northeast British Columbia rich gas, as well as delivery of gas and liquids to export markets.

Aux Sable US is pursuing several growth initiatives focused primarily on the growing shale oil/gas developments in the US midwestern and eastern areas where access to the Channahon facility and the Palermo Conditioning Plant can be competitive. These growth initiatives are expected to provide accretive and predictable earnings over and above the cash flow generated from Aux Sable US's existing NGL facilities.

Competition

In the Dawson region where Veresen Midstream acquired the assets from Encana and CRP in 2015 we have an AMI and Dawson MSA in place with Encana and CRP. This AMI requires Encana/CRP to utilize the infrastructure governed under the Dawson MSA for their gas midstream needs and is expected to result in strong facility utilization. In the event that Encana/CRP do not utilize the full facility capacity Veresen Midstream searches out additional gas which could be transported, compressed or processed at the facilities to maximize throughput.

In the Hythe/Steeprock area Veresen Midstream has a take-or-pay commitment from Encana for the majority of the current available capacity of these facilities over the duration of the Hythe/Steeprock MSA. As such Encana is incentivized to flow gas volumes to these facilities and it is expected that they will remain near capacity for a significant period of time. In the event that Encana is not fully utilizing their processing capacity at these facilities, Veresen Midstream may seek third party volumes to maximize facility utilization.

The oil and gas midstream sector in Canada is a competitive market with a number of strategic and financial companies seeking investment opportunities. When evaluating new investment opportunities Veresen Midstream competes with these companies.

Aux Sable Liquid Products LP has the exclusive right to extract NGL from all of the natural gas transported by the shippers on the Alliance Pipeline for the period of the transportation agreements. Aux Sable has signed RGP Agreements with gas producers in the Montney and Duvernay areas of Alberta and British Columbia for delivery of rich gas onto the Alliance Pipeline to the Channahon facility for processing in the post December 2015 time period. These RGP Agreements are expected to result in the transportation of up to 1.2 bcf/d of rich gas on the Alliance Pipeline to Aux Sable's Channahon facility.

The Midstream Industry

Natural gas is a mixture of various hydrocarbon components. The main component of natural gas is methane but it also contains other higher value hydrocarbons that are in gaseous form at the typical pressures and temperatures under which natural gas is transported and consumed. The higher value components are referred to as NGL and consist of ethane, propane, normal butane, iso-butane and condensate (pentanes plus) and mixtures thereof. NGL are recovered primarily from three sources: field plants (such as the Hythe/Steeprock gas plants), straddle plants (such as the Channahon facility) and oil refineries.

The natural gas midstream industry provides the infrastructure required to handle natural gas and NGL from the wellhead all the way to end markets. We are involved in a number of key areas of the natural gas midstream industry as described below:

- field gathering infrastructure – pipelines that are used to gather natural gas from the wells in the field and transport the gas to a field processing facility;
- field compression – compressors that increase the pressure of the natural gas for the purposes of transportation;
- field processing facilities – plants that process raw natural gas produced from wells in the area of the field plant to remove impurities such as water, sulphur and carbon dioxide and which may extract some or a majority of the NGL. There are in excess of 300 field plants that extract NGL in western Canada;

- gas transmission pipelines – pipelines that transport gas which has been processed through a field processing facility to a market center. This gas may be further processed at a straddle plant;
- straddle plants –plants that reprocess the natural gas to extract more refined NGL. In western Canada there are eight straddle plants which extract approximately one-third of the total propane and butane recovered. Straddle plants in Canada are found on major high volume gas transmission systems, other than the Alliance Pipeline, that transport natural gas from the producing region to end markets;
- fractionation facilities – to meet end-user needs with specification products, the NGL mix must be separated into its constituent components. Most field or straddle plants in Alberta produce an NGL mix that is shipped to Edmonton or Sarnia for subsequent separation; and
- NGL transportation – pipelines, trucks, barges and ships used to transport NGL from fractionation facilities to end markets.

NGL is used directly as an energy product and as feedstock for the petrochemical and crude oil refining industries. Uses for propane include primarily home and industrial heating, crop drying, cooking and motor fuel. Butane is used in gasoline blending. Condensate is used in crude oil blending and as a refinery feedstock to make gasoline. The petrochemical industry uses ethane as a feedstock.

The petrochemical industry can use NGL as a feedstock for producing ethylene, propylene, butadiene and other NGL derivatives. These intermediate compounds form the raw materials for end-use products such as polyethylene, polypropylene, plastics, solvents and foam materials.

Market Demand

As NGL in North America are used as both a heating fuel and as a petrochemical/refining feedstock, general demand for these liquids is influenced by weather conditions as well as by the overall level of economic activity. With the increase in NGL supply associated with shale oil/gas developments, export markets (and associated export terminals) are currently being developed (primarily propane). There are plans to significantly increase consumption of ethane and propane feedstocks for new or expanded North American petrochemical facilities that will export plastics (primarily polyethylene) into world markets.

NGL Economics

Plants that extract NGL from natural gas must have an agreement with the owner of the natural gas to allow the processing of the natural gas and the extraction of the NGL. There are several types of agreements used by the midstream industry in the US and Canada. Where an agreement requires the processor to replace the energy removed from the natural gas when the NGL is extracted, the processor must purchase make-up gas to replace the heating content removed due to the extraction of NGL. The cost of make-up gas is the largest cost component in the production of NGL. As NGL product prices tend to vary with oil prices, the relative spread between natural gas prices and oil prices influences gross margins in the midstream business. The impact on margins can be dramatic during periods when the prices of NGL and natural gas move at different rates or in different directions. Other arrangements may involve a firm processing fee, a cost of service fee or a fee equal to a percentage share of the value of the NGL extracted, or variations that involve various components of these arrangement types, with the NGL sales agreement being such a hybrid form of arrangement.

OUR POWER BUSINESS

Map of Our Power Business

Overview of Our Power Business

Our Power Business, as at the date of this Annual Information Form, is comprised of the following operating facilities:

Facility	Location	Approximate Capacity	Ownership	Fuel	Counterparty	Contract Expiry	Operator
Clowhom (2 facilities)	Sechelt, BC	22 MW (2 x 11 MW)	100%	Hydroelectric	BC Hydro	2035	Veresen
Dasque-Middle	Terrace, BC	20 MW (Dasque – 11 MW) (Middle – 9 MW)	100%	Hydroelectric	BC Hydro	2055	Veresen
East Windsor Cogeneration Centre	Windsor, ON	84 MW	100%	Natural Gas	IESO	2029	Veresen
EnPower (2 facilities)	150 Mile House and Savona, BC	10 MW (2 x 5 MW)	100%	Waste Heat	BC Hydro	2028	Spectra Energy Corp.
Furry Creek	Squamish, BC	11 MW	99%	Hydroelectric	BC Hydro	2024	Veresen
Glen Park	Watertown, NY	33 MW	100%	Hydroelectric	Shell Energy North America (US), L.P.	month to month	Northbrook Power Management, LLC
Grand Valley I & II	Grand Valley, ON	20 MW	75%	Wind	IESO	2032	Veresen
Grand Valley III	Grand Valley, ON	40 MW	75%	Wind	IESO	2035	Veresen
London Cogeneration	London, ON	19.5 MW	100%	Natural Gas	IESO	2028	Veresen
London District Energy	London, ON	100 MW (thermal energy)	100%	Natural Gas	approximately 65 government, commercial and residential buildings	variable	Veresen
NRGreen (4 facilities)	Alameda, Estlin, Loreburn and Kerrobert, SK	20 MW (4 x 5 MW)	50%	Waste Heat	Saskatchewan Power Corporation	2016-2018 (2, 5-yr renewal options)	Alliance Canada
PEI District Energy	Charlottetown, PEI	72 MW (thermal energy)	100%	Biomass and waste	More than 120 government, commercial and residential buildings	variable	Veresen
St. Columban I	Seaforth, ON	18 MW	90%	Wind	IESO	2035	Veresen
St. Columban II	Seaforth, ON	15 MW	90%	Wind	IESO	2035	Veresen
York Energy Centre	Township of King, ON	400 MW	50%	Natural Gas	IESO	2032	Veresen
Whitecourt Recovered Energy Facility	Whitecourt, AB	13.8 MW	50%	Waste Heat	Alberta Power Pool	N/A	Alliance Canada

The following facility is under development as at the date of this Annual Information Form:

Facility	Location	Approximate Capacity	Ownership	Fuel	Counterparty	Contract Term	Status
London Cogen II	London, ON	18 MW	100%	Natural Gas	IESO	2035	Under development – expected in-service Q2 2019

Regulatory Environment

Canada

In Canada, electricity markets have developed within provincial boundaries with electricity historically supplied by vertically-integrated utilities, often provincially-owned, that provide generation, transmission and distribution services. Many of the provinces have now restructured their electricity markets to separate generation, transmission and distribution services to facilitate competition in electricity generation, the development of privately-owned generation assets and provide customer choice. Wholesale access to transmission grids and the provision of Open Access Transmission Tariffs (OATTs) has been introduced in several provinces enabling customers to use the grid to deliver electricity and allowing customers to purchase electricity from the most competitive generation sources.

The extent of restructuring varies across Canada. Alberta and Ontario have moved the furthest in restructuring with both markets having a spot power market with multiple buyers and sellers and providing for wholesale and retail access. A notable difference in these markets is that supply in Alberta is built "at risk", or on a merchant basis, while almost all new generation in Ontario is procured by the IESO (Independent Electricity System Operator) through long-term contracts with the IESO.

Generally, power project development starts with an identified need for generation. The identified need may require a generator to run only when needed for peak loads, called peaking generation, or a generator to run for most of the time, called baseload generation. Alternatively, the demand for resources may be policy driven, such as for renewable or "clean" power, or the generation may be required for transmission system support purposes.

In Ontario and British Columbia, the introduction of OATTs has resulted in tendering processes for new generation conducted by the IESO and BC Hydro, respectively. These processes allow independent power producers to bid for long-term contracts for the sale of a variety of electrical resources, typically with geographical exclusions and incentives. Alberta has developed as a market in which merchant capacity is developed for sale to the spot market, or resources are auctioned or sold to term customers according to prevailing market conditions.

Ontario

Ontario's electricity market has undergone a supply transformation over the past several years with the commitment to close down its coal fired generation facilities by 2015, which was achieved, and the procurement of gas fired generation and renewable energy as part of the supply mix. The IESO, the province's lead agency responsible for long-term electricity planning, released its 2013 Long Term Energy Plan, *Achieving Balance*, in November 2013. The Plan confirms that while Ontario is currently in a strong supply situation, flexibility must be maintained in order to meet changes in the demand for electricity. Conservation, renewables, nuclear energy and high efficiency natural gas generation will all play a role in maintaining a stable and reliable energy supply. All of our power generation facilities in Ontario including the York Energy Centre, the East Windsor Cogeneration Centre, Grand Valley Wind Farms, St. Columban Wind Farms and London Cogeneration hold long-term electricity supply contracts with the IESO (formerly the Ontario Power Authority).

British Columbia

The majority of British Columbia's electricity is provided by BC Hydro, a government-regulated utility, with approximately 20% generated by independent power producers. BC Hydro forecasts that the energy requirements of the province will increase by 40% over the next 20 years, and is highly focused on planning for this additional load. The proposed development of new mines, LNG terminals and northern gas fields has shifted the future load demand to the north coast and northwest area of the province.

BC Hydro released its Integrated Resource Plan (IRP) 2013 in November 2013. The IRP addresses how BC Hydro will meet the forecast energy needs of the next 20 years and support the development of LNG by the use of clean and renewable power. While existing generation and conservation efforts will address demand growth in the short term, the IRP forecasts the emergence of a supply-demand gap within the next 10 years. In June of 2012, the British Columbia government amended the *Clean Energy Act* by deeming electricity generated from natural gas as a "clean" source of power when used to power LNG facilities in British Columbia.

United States

The FERC regulates the rates, tariffs, services and corporate organization and finance of most US non-governmental power transmitters and wholesale power sellers. The Glen Park facility is a hydropower licensee, a public utility and a qualifying small power production facility, subject to regulation by the FERC. The Glen Park facility is interconnected to the electric transmission system of the New York Independent System Operator, at a point of interconnection owned by National Grid USA. Glen Park's hydroelectric power license is in effect until November 30, 2032. Separate and apart from relicensing requirements, the Glen Park facility's hydropower license causes the facility to be subject to the FERC regulation of hydropower safety, water quality, environmental protection, land use, dam integrity, and emergency-response matters.

Environmental Matters

Canada

The Canadian power industry is subject to environmental legislation pursuant to local, provincial and federal requirements. This legislation provides for restrictions on air emissions and water usage from power generation facilities that combust fuels such as natural gas, or that use water as a fuel source such as in hydroelectric generation. These restrictions can significantly affect the operation of a facility and non-compliances may result in the imposition of fines or issuance of abatement orders. Our facilities are subject to environmental performance standards as described in each facility's operating permits, licenses and approvals.

Provincially, the governments of British Columbia, Ontario, Manitoba and Quebec have joined with the US state of California, in a regional effort committed to reducing total GHG emissions. The first step towards implementing GHG emission reduction targets is to mandate GHG reporting. The Canadian Federal Government and the provincial governments of Ontario, PEI and British Columbia have enacted legislation requiring facilities to report their annual GHG emissions. While each of these provinces require GHG reporting, they have not yet implemented GHG reduction targets or established a cap and trade program. Ontario Regulations 397/07 and 194/05, made under the *Environmental Protection Act* (Ontario), set limits on emissions of nitrogen oxides (NO_x) and sulphur dioxide (SO_2) from electricity generating facilities that use fossil fuels. To assist electricity generating facilities in meeting their NO_x and SO_2 limits, the Ontario government established a cap and trade system. Under the existing system, cleaner sources of power generation, such as natural gas-fired facilities are eligible to receive and sell excess emission allowances with respect to NO_x and SO_2. The Ontario government is targeting to implement the GHG cap and trade program by the first quarter of 2017.

In British Columbia, the operation of renewable energy facilities such as run-of-river facilities are subject to water use requirements including meeting specified in-stream flow requirements and flow ramping criteria. These two parameters were established in order to mitigate potential environmental effects resulting from the diversion of water to produce electricity. Both in-stream flow requirements and flow ramping rates are stipulated as part of a facility's Operating Parameters and Procedures Report. A facility's license to operate is provided via issuance of a Final Leave to Operate.

While we expect that each of our power and district energy facilities will be in a positive or neutral emissions compliance position, there can be no guarantee that the projects will meet the required standards. Under the terms of the respective combined heat and power contracts and the peaking generation contract, the IESO is entitled to all rights, title and interest in all environmental attributes such as GHG compliance units that are created and allocated or credited to each of the London and East Windsor cogeneration facilities, and the York Energy Centre. If any of these facilities require Canadian federal GHG environmental attributes to operate the facility, their corresponding contracts with the IESO provide some additional contractual protection against adverse economic effects on the applicable facility. Environmental attributes such as NO_x and SO_2 emission allowances are retained by the facilities and are not transferred to the OPA. Potential emission credits from the waste heat recovery and electrical power generation (WHPG) facilities of NRGreen are owned by SaskPower, and therefore are neutral to NRGreen.

All of our Canadian power generation facilities are subject to federal, provincial and local laws and regulations relating to the protection of the environment. These facilities are in material compliance with applicable environmental laws.

United States

Our US power facility and its operations are subject to environmental health and safety regulatory regimes including federal, state, regional, local and municipal laws, regulations and permits relating to, among other things: air emissions, water and wastewater treatment, worker health and safety and site contamination. We believe that our facility has obtained and is currently in material compliance with, the material environmental permits and approvals currently necessary to operate the facility.

Outlook

We continue to evaluate opportunities to expand upon our existing base of power assets and capitalize on the independent power market by focusing on the development of new gas fired generation opportunities using proven technologies. Our Grand Valley Wind Farms – Phase III project recently reached its commercial operation date while we continue to develop our London Cogen II combined heat and power project toward an anticipated in-service date of the second quarter of 2019.

Future development will continue on projects that provide for a basis for long-term contracts with load-serving entities that fit with our portfolio and operating base from a technology, size and geographical perspective. This includes a focus on gas fired generation and combined heat and power opportunities.

At the PEI district energy system, we continue to evaluate opportunities to provide service to existing buildings not currently connected to its system and to new buildings in close proximity to its distribution network. We are also evaluating expanding use of municipal waste fuels in support of reducing the amount of waste going to local landfills, while concurrently providing customers with a competitive long-term energy supply. Small-scale cogeneration, utilizing the PEI system as the thermal load, continues to be evaluated.

At the London district energy system, we continue to pursue expansion opportunities in both steam and chilled water markets to increase facility capacity and flexibility. In Ontario, it is expected that further

opportunities may present themselves for district energy systems in further procurements by the IESO for combined heat and power projects.

Competition

All of the power generation and WHPG facilities are situated in competitive markets and compete with other companies involved in power generation. However, most of the power generation facilities have entered into long-term contractual agreements that serve to reduce the potential impact of this competition throughout the contract term. No assurances can be given that these agreements will be replaced with new agreements on substantially the same terms following the end of their existing term. The primary competition in the power generation business is associated with the competitive process of acquiring off-take contracts or facility acquisitions.

The London and PEI district energy systems compete with a wide variety of firms that sell products or services to end-users who choose to build and operate heating and cooling equipment on their own premises. These firms include suppliers of boilers and chillers and fuel suppliers such as gas and electric utilities, which encourage use of equipment that use their products. Rising energy costs for industrial and commercial consumers, coupled with new environmental initiatives, have encouraged the expansion of existing district energy systems and the development of new systems in Canada. The London and PEI district energy systems have entered into long-term contractual agreements that serve to reduce the potential impact of this competition.

JORDAN COVE ENERGY PROJECT AND PACIFIC CONNECTOR GAS PIPELINE

In early 2011, we began pursuing a proposed business opportunity for the development, construction, and operation of a liquefied natural gas (LNG) production and export facility, and a related natural gas pipeline on the west coast of the United States. We intend to site an LNG export terminal, known as Jordan Cove LNG, within the International Port of Coos Bay in Coos County, Oregon. Additionally, we intend to construct a natural gas pipeline, known as the Pacific Connector Gas Pipeline (Pacific Connector), which will connect the Jordan Cove LNG terminal to large-volume natural gas supply pipelines and gas production regions within the US Rockies and western Canada. Once in-service, the facilities are expected to be available for use by customers that have executed long-term service contracts.

Jordan Cove LNG and Pacific Connector are intended to be located on sites and rights-of-way previously considered by us for development of an LNG import, or "*regasification*", business. The regasification business opportunity pursued from late 2005 through 2010 was terminated due to significantly increased levels of North American natural gas supply.

Our initial development plan involves the construction of a natural gas liquefaction plant capable of producing and exporting a minimum of 6 mtpa. The related Pacific Connector pipeline will be 400-km in length, 36 inches in diameter, and will include appurtenant facilities required for compression, metering, receipt and delivery of natural gas.

In December 2011, Jordan Cove LNG received approval from the US Department of Energy to export up to 9 mtpa of LNG, for a 30-year term, to any nation that has a free trade agreement in place with the US requiring national treatment for trade in natural gas. In March 2014, we received conditional approval from the US Department of Energy to export up to 6 mtpa of LNG, for a 20-year term, to nations that do not have a free trade agreement with the US.

In 2011 we acquired certain land required for the future construction and operation of the Jordan Cove LNG terminal. In late 2012, we acquired additional land needed for the LNG facility as well as adjacent development and other environmental mitigation lands. The cumulative land purchased to date is approximately 510 acres.

In February 2012, under the requirements of the United States' *National Environmental Policy Act*, we initiated formal pre-filing applications with the FERC for each of Jordan Cove LNG and Pacific Connector. A completed application seeking authorization to construct and operate Jordan Cove LNG was formally filed with the FERC in May 2013. A formal FERC application for Pacific Connector was filed in June 2013.

In August 2012, Jordan Cove LNG filed a notice of intent with the Oregon DOE for the construction and operation of a power plant, notionally called the South Dunes Power Plant. Following a public review process, a preliminary application was filed in January 2014 and, in December 2014, with the Oregon DOE issuing a completeness determination, a completed application was filed. In October 2015, the Oregon DOE issued a Proposed Order in respect of our application. Procedural next steps include a mandatory Contested Case process, issuance of a final Order and then, to complete the process, the Oregon DOE's issuance of a Site Certificate.

In September 2013, we filed an application with the NEB, as agent for our prospective liquefaction-tolling customers, for a long-term license to export natural gas from Canada to the US, which would ensure long-term natural gas feed stock to Jordan Cove LNG. In October 2013, we filed an application with the US Department of Energy to import this same quantity of natural gas supply from Canada into the US. The applications requested 1.55 bcf/d of export and import volumes, respectively, which will satisfy our initial development plan along with anticipated expansion needs. The NEB approved our long-term license application to export 1.55 bcf/d of natural gas for 25 years in February 2014. The US Department of Energy (DOE) approved our application to import the same quantity of natural gas supply in March 2014. In July 2015, Canada's federal government provided final Governor-in-Council approval of the NEB's authorization.

In May 2014, we engaged Macquarie Capital as financial advisors for Jordan Cove LNG. Macquarie Capital's advisory services consist of various project requirements including coordination of planned debt and equity processes for financing of the construction of the LNG export facility.

In October 2014, Elizabeth Spomer was appointed President and Chief Executive Officer of Jordan Cove LNG LLC and Executive Vice President of Veresen Inc. Ms. Spomer oversees the development activities of Jordan Cove LNG and Pacific Connector. In preparation for the prospect of a positive Final Investment Decision, we have assembled an experienced, Houston-based, LNG project team to manage the development and construction of Jordan Cove LNG, and to prepare for long-term facility operations.

In November 2014, the FERC issued a draft Environmental Impact Statement for Jordan Cove LNG and Pacific Connector and, in September 2015, the FERC issued its Final Environmental Impact Statement.

In March 2016, we received an order from the FERC denying the applications of Jordan Cove LNG and Pacific Connector for authorization to site, construct and operate the Jordan Cove LNG export terminal and Pacific Connector natural gas pipeline. Jordan Cove LNG and Pacific Connector will file a request for a rehearing of this decision.

Jordan Cove Energy Project LP, the entity developing Jordan Cove LNG, is a wholly owned subsidiary of ours. We and an affiliate of the Williams Companies, Inc. equally own Pacific Connector Gas Pipeline, LP, the entity developing Pacific Connector. Energy Fundamentals Group Inc. (EFG) has an option to acquire up to 20% of our equity interest in Jordan Cove LNG, such option to be exercisable prior to or within 5 days of the closing of the financing for the construction of the LNG terminal. Upon exercise of the option, EFG must pay us an amount equal to its share of all development and construction equity contributed prior to that time, together with a premium after tax rate of return of 30% on development equity, and 10.25% on construction equity, if any, in each case compounded annually, on such equity amounts from the time such costs were incurred.

Over the course of the previous 4 years, we have promoted and marketed the project's viability and credibility to prospective customers. To that end, commercial discussions are ongoing with a number of high-quality prospective customers capable of contracting for long-term liquefaction capacity, and who may possibly become minority equity partners in Jordan Cove LNG.

OTHER INITIATIVES

Ethane Storage Facility

On November 6, 2015, we announced that we intend to build and operate a new wholly-owned ethane storage facility located near Burstall, Saskatchewan which is approximately 20 km north of the Empress NGL complex. This salt cavern facility is expected to have capacity to store approximately 1 million bbls of ethane and will be connected via pipeline to AEGS. Our anticipated capital cost for the storage facility and related infrastructure is approximately $140 million.

A wholly-owned subsidiary of ours and NOVA Chemicals Corporation (NOVA) have entered into an agreement where NOVA will use the majority of the storage capacity of the facility under a long term 20 year arrangement. We are actively pursuing customers for use of the remaining available storage capacity. Construction of the storage facility has commenced and the facility is expected to be in service the second half of 2018, subject to regulatory approvals.

ENVIRONMENTAL, HEALTH & SAFETY PROGRAM

We have established an EHS Program based on the achievement of corporate-wide EHS objectives. The foundation of our program begins with our EHS Policy. The EHS Policy demonstrates management's commitment to ensuring the protection of our employees, stakeholders and the environment. It provides the basis for ensuring the adequacy of EHS resources and adhering to industry best practices in the achievement of our business goals. Corporate governance over EHS matters is provided by the Environmental, Health and Safety Committee of our Board of Directors.

Our corporate-wide EHS objectives apply directly to our midstream, power generation and district energy facilities that are owned by us and operated either directly by us or indirectly through a third party contractor. We also monitor the EHS performance of Alliance, Aux Sable and AEGS on at least a quarterly basis.

Our EHS Program revolves around our EHS Management System which incorporates a variety of tools when carrying out our EHS goals. These include establishing EHS Management Plans for all of our operating facilities and projects under construction. The EHS Management Plans incorporate overarching directives and facility specific procedures. To better manage our program, we implemented our SMART system. SMART is an electronic sustainability management and compliance reporting program that centralizes our EHS information, including document management, incident reporting and compliance reporting for all of our operating facilities and projects under construction and development. All of these elements combine into a single framework that incorporates regulations, policies, procedures, people, and plans to best manage our EHS risks across the organization. Our program utilizes key elements of the ISO 14001 and ISO 18001 framework.

A key element of our EHS Management System is assurance. We have a comprehensive monitoring and measurement program in place to ensure our activities, processes, and systems are reviewed and audited at appropriate levels and intervals. Our annual plans, activities, and goals include metrics and targets to focus our organization on best-in-class performance and continuous improvement.

RISK FACTORS

We discuss our risk factors in our MD&A for the year ended December 31, 2015, under the subheading "Risks", which is incorporated in this Annual Information Form by reference.

DESCRIPTION OF CAPITAL STRUCTURE

We are entitled to issue an unlimited number of Common Shares and a number of Preferred Shares, issuable in series, to be limited to an amount equal to not more than one-half of the number of Common Shares issued and outstanding at the time of issuance of such Preferred Shares. We currently have outstanding Common Shares, Series A Preferred Shares, Series C Preferred Shares and Series E Preferred Shares.

The following is a summary of the rights, privileges, restrictions and conditions attaching to the securities that comprise our existing share capital.

Common Shares

Each Common Share entitles the holder to one vote at all meetings of Shareholders, except meetings at which only holders of a specified class of shares are entitled to vote. Subject to the prior rights and privileges attaching to any other class of shares of Veresen Inc., holders of Common Shares have the right to receive any dividend declared by our Board of Directors on the Common Shares and the right to receive the remaining property and assets of Veresen Inc. upon dissolution.

We adopted a rights plan (Rights Plan), the terms and conditions of which are set out in the Shareholder Rights Plan Agreement dated as of May 6, 2014, which agreement amended and restated the Shareholder Rights Plan Agreement dated January 1, 2011. Under the Rights Plan, one right was issued with each Common Share issued in connection with the Arrangement and one right will be issued with each Common Share subsequently issued prior to the expiration or termination of the rights. The rights remain attached to the Common Shares and are not exercisable or separable unless one or more certain specified events occur. If a person or group acting in concert acquires 20% or more of the Common Shares, the rights will entitle the holders thereof (other than the acquiring person or group) to purchase Common Shares at a 50% discount from the then market price. The rights are not triggered by a "Permitted Bid" (as defined in the Shareholder Rights Plan Agreement).

The Rights Plan will expire on the earlier of the Termination Time (as defined in the Shareholder Rights Plan Agreement) and the termination of the annual meeting of Shareholders in the year 2017 or, if ratified at such annual meeting, the earlier of the Termination Time and the termination of the annual meeting of Shareholders in the year 2020.

Preferred Shares

The Preferred Shares may at any time and from time to time be issued in one or more series, each series to consist of such number of shares as may, before the issue thereof, be determined by our Board of Directors, provided that the number of Preferred Shares of all series shall 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. Subject to the provisions of the ABCA, our Board of Directors may fix from time to time, before the issue thereof, the designation, rights, privileges, restrictions and conditions attaching to each series of the Preferred Shares.

Series A Preferred Shares

In February 2012, we issued 8,000,000 Series A Preferred Shares. The holders of our Series A Preferred Shares are entitled to receive fixed cumulative dividends at an annual rate of 4.40%, payable quarterly,

commencing June 30, 2012, for an initial period up to but excluding September 30, 2017, as and when declared by our Board of Directors. The dividend rate will reset on September 30, 2017 and every five years thereafter at a rate equal to the sum of the then five-year Government of Canada bond yield plus 2.92%. The Series A Preferred Shares are redeemable by Veresen Inc., at its option, on September 30, 2017 and on September 30 of every fifth year thereafter.

Holders of Series A Preferred Shares will have the right to convert all or any part of their shares into our Series B Preferred Shares subject to certain conditions, on September 30, 2017, and on September 30 of every fifth year thereafter. The holders of Series B Preferred Shares will be entitled to receive quarterly floating rate cumulative dividends, as and when declared by our Board of Directors, at a rate equal to the sum of the then 90-day Government of Canada treasury bill rate plus 2.92%.

Series C Preferred Shares

In October 2013, we issued 6,000,000 Series C Preferred Shares. The holders of our Series C Preferred Shares are entitled to receive fixed cumulative dividends at an annual rate of 5.0%, payable quarterly, commencing December 31, 2013, for an initial period up to but excluding March 31, 2019, as and when declared by our Board of Directors. The dividend rate will reset on March 31, 2019 and every five years thereafter at a rate equal to the sum of the then five-year Government of Canada bond yield plus 3.01%. The Series C Preferred Shares are redeemable by Veresen Inc., at its option, on March 31, 2019 and on March 31 of every fifth year thereafter.

Holders of Series C Preferred Shares will have the right to convert all or any part of their shares into our Series D Preferred Shares subject to certain conditions, on March 31, 2019, and on March 31 of every fifth year thereafter. The holders of Series D Preferred Shares will be entitled to receive quarterly floating rate cumulative dividends, as and when declared by our Board of Directors, at a rate equal to the sum of the then 90-day Government of Canada treasury bill rate plus 3.01%.

Series E Preferred Shares

In April 2015, we issued 8,000,000 Series E Preferred Shares. The holders of our Series E Preferred Shares are entitled to receive fixed cumulative dividends at an annual rate of 5.0%, payable quarterly, commencing June 30, 2015, for an initial period up to but excluding June 30, 2020, as and when declared by our 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 Veresen Inc., at its option, on June 30, 2020 and on June 30 of every fifth year thereafter.

Holders of Series E Preferred Shares will have the right to convert all or any part of their shares into our 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, at a rate equal to the sum of the then 90-day Government of Canada treasury bill rate plus 4.27%.

DIVIDENDS

There are no restrictions that currently prevent us from paying dividends. However, the ABCA provides that a corporation shall not declare or pay a dividend if there are reasonable grounds for believing that (i) the corporation is, or would after the payment be, unable to pay its liabilities as they become due, or (ii) the realizable value of the corporation's assets would thereby be less than the aggregate of its liabilities and stated capital of all classes. Restrictions in the credit or financing agreements we or any of our subsidiaries or operating entities may have entered into may preclude or restrict the payment of dividends in certain circumstances. We discuss restrictions on our ability to make cash dividends in our MD&A for

the year ended December 31, 2015, which discussion is incorporated in this Annual Information Form by reference.

We currently pay dividends on our Common Shares on a monthly basis to Shareholders of record on the last business day of the applicable month. Payments are made on the 23rd day of the month immediately following, or, if the 23rd day is not a business day, then on the immediately preceding business day. We also currently pay, on a quarterly basis, a fixed cumulative preferential cash dividend at an annual rate of 4.40% on our Series A Preferred Shares and at an annual rate of 5.0% on both our Series C Preferred Shares and Series E Preferred Shares to holders of record on the close of business on the 15th day of the month in which the quarter ends, or if the 15th day of the month is not a business day, then on the immediately preceding business day. Payments are made on the last day of the month in which the quarter ends. We expect to designate any dividends paid on Common Shares, Series A Preferred Shares, Series C Preferred Shares and Series E Preferred Shares as "eligible dividends" for Canadian federal income tax purposes, which are anticipated to qualify for the enhanced federal dividend tax credit in Canada.

We declared and paid the dividends set forth in the tables below to (i) holders of Common Shares in 2013, 2014 and 2015, (ii) holders of Series A Preferred Shares in 2013, 2014 and 2015, (iii) holders of Series C Preferred Shares in 2013, 2014 and 2015, (iv) holders of Series E Preferred Shares in 2015:

	2015	2014	2013
Dividends paid ($ per Common Share)	1.00	1.00	1.00
Dividends paid ($ per Series A Preferred Share)	1.10	1.10	1.10
Dividends paid ($ per Series C Preferred Share)	1.25	1.25	0.2432
Dividends paid ($ per Series E Preferred Share)	0.9332	-	-

RATINGS

Our 4.00% medium term notes, series 1 due 2018, 3.95% medium term notes, series 2 due 2017, 5.05% medium term notes, series 3 due 2022 and 3.06% medium term notes, series 4 due 2019 have each been assigned credit ratings of BBB with a stable trend by DBRS and BBB with a stable outlook by S&P. Both DBRS and S&P rate debt securities with ratings ranging from "AAA", the highest credit quality of securities, to "D" which represents securities that are in payment default. According to the DBRS rating system, long-term debt rated BBB is of adequate credit quality. The capacity for the payment of financial obligations is considered acceptable, although DBRS considers that such obligations may be vulnerable to future events. A DBRS rating may be modified by the addition of "high" or "low" to indicate the relative standing of a credit within a particular rating category. The absence of either a "high" or "low" designation indicates that the rating is in the "middle" of the category. According to the S&P rating system, debt securities that are rated in the BBB category are considered by S&P to exhibit adequate protection parameters. However, S&P considers that adverse economic conditions or changing circumstances are more likely to lead to a weakened capacity of the issuer to meet its financial commitments on the obligation. An S&P rating may be modified by the addition of a plus "(+)" or minus "(–)" to show relative standing within the particular major rating category. A credit rating is not a recommendation to buy, sell or hold securities and may be subject to revision or withdrawal at any time by the particular rating organization.

The Series A Preferred Shares, Series C Preferred Shares and Series E Preferred Shares have each been rated Pfd-3 by DBRS and P-3 (High) by S&P. Ratings are intended to provide investors with an independent measure of credit quality of an issue of securities. The rating agencies' ratings for preferred shares range from a high of Pfd-1 to a low of D for DBRS and from a high of P-1 to a low of D for S&P.

A Pfd-3 rating by DBRS is the third highest of six categories granted by DBRS. According to the DBRS rating system, securities rated Pfd-3 are of adequate credit quality. While protection of dividends and principal is still considered acceptable, the issuing entity is more susceptible to adverse changes in financial and economic conditions, and there may be other adverse conditions present which detract from debt protection. Subcategories of "high" or "low" grades are used to indicate the relative standing within a rating category. The absence of either a "high" or "low" designation indicates the rating is in the middle of the category.

A P-3 rating by S&P is the third highest of eight categories granted by S&P. According to the S&P rating system, while securities rated P-3 are regarded as having significant speculative characteristics, they are less vulnerable to non-payment than other speculative issues. However, such securities face major ongoing uncertainties or exposure to adverse business, financial, or economic conditions which could lead to the obligor's inadequate capacity to meet its financial commitment on the obligation. The ratings from P-1 to P-5 may be modified by "High" and "Low" grades which indicate relative standing within the major rating categories.

MARKET FOR SECURITIES

Our Common Shares, Series A Preferred Shares, Series C Preferred Shares and Series E Preferred Shares are each listed and posted for trading on the TSX under the symbols VSN, VSN.PR.A, VSN.PR.C and VSN.PR.E, respectively.

Common Shares

The following table sets forth the high and low sale prices and the trading volumes for our Common Shares on a monthly basis as reported by the TSX for our most recently completed financial year:

	Price Range		
	High ($)	**Low ($)**	**Volume**
2015			
January	18.41	14.84	12,609,443
February	16.62	15.11	10,780,840
March	16.68	13.52	16,613,573
April	19.00	16.24	16,906,208
May	19.40	17.28	36,964,083
June	18.80	16.38	13,629,193
July	17.05	14.49	15,619,226
August	14.70	11.21	17,118,839
September	13.47	9.80	15,287,177
October	12.77	9.77	19,826,923
November	11.37	10.19	18,110,795
December	10.62	8.43	22,520,478

Series A Preferred Shares

The following table sets forth the high and low sale prices and the trading volumes for our Series A Preferred Shares on a monthly basis as reported by the TSX for our most recently completed financial year:

	Price Range		
	High ($)	**Low ($)**	**Volume**
2015			
January	25.47	22.05	84,847
February	25.45	21.91	144,136
March	22.88	20.50	201,539
April	21.49	19.29	321,403
May	21.51	20.02	122,976
June	21.26	19.46	157,962
July	19.79	17.55	247,701
August	17.75	14.70	491,804
September	16.13	13.55	194,974
October	17.50	13.21	312,579
November	17.27	15.35	358,428
December	16.49	13.60	364,118

Series C Preferred Shares

The following table sets forth the high and low sale prices and the trading volumes for our Series C Preferred Shares on a monthly basis as reported by the TSX for our most recently completed financial year:

	Price Range		
	High ($)	**Low ($)**	**Volume**
2015			
January	25.35	24.13	212,171
February	25.38	24.09	98,066
March	25.19	23.49	228,487
April	23.96	21.80	168,915
May	24.00	23.15	61,016
June	23.50	22.67	112,120
July	23.18	21.25	74,098
August	21.39	17.52	78,461
September	18.94	15.59	169,275
October	19.08	15.07	210,423
November	19.01	17.00	206,527
December	17.55	15.19	334,687

Series E Preferred Shares

The following table sets forth the high and low sale prices and the trading volumes for our Series E Preferred Shares on a monthly basis as reported by the TSX for our most recently completed financial year:

	Price Range		
	High ($)	Low ($)	Volume
2015			
April	24.92	24.00	1,212,388
May	25.40	24.52	748,541
June	25.30	24.60	271,152
July	25.19	24.01	153,040
August	24.30	18.73	188,671
September	23.59	19.45	203,843
October	22.94	19.18	217,968
November	23.50	20.30	173,235
December	21.41	16.50	391,649

DIRECTORS AND OFFICERS

The table below provides information about each of our current directors and executive officers including their name, city, province or state and country of residence, date first elected or appointed a director, principal occupation, business or employment for the five preceding years and the number of Common Shares beneficially owned, or controlled or directed, directly or indirectly, as at March 14, 2016. The term of office for each director will expire at the next annual meeting of Shareholders.

Name, Residence and Shareholdings	Director Since	Veresen Position (if applicable) and Principal Occupation During Five Preceding Years
Directors		
J. Paul Charron [(2)(3)] Calgary, Alberta, Canada 35,000 Common Shares held	January 17, 2011	Chairman and Chief Executive Officer of CanEra Inc. (private oil and gas company) since October 2014; prior thereto President and Chief Executive Officer of CanEra Energy Corp. (private oil and gas company) from September 2010 to May 2014.
Maureen E. Howe [(1)(3)] Vancouver, British Columbia, Canada 8,500 Common Shares held	May 1, 2012	Retired.
Robert J. Iverach [(3)(4)] Calgary, Alberta, Canada 5,600 Common Shares held [(5)]	May 10, 2007	Barrister & Solicitor.
Rebecca A. McDonald [(1)(4)] Houston, Texas, U.S.A. 500 Common Shares held	July 3, 2008	Retired in 2012; prior thereto Chief Executive Officer of Laurus Energy Inc. (underground coal gasification company) from December 2008 to July 2012.
Stephen W. C. Mulherin [(2)(3)(6)] Calgary, Alberta, Canada 50,000 Common Shares held	October 9, 1997	Partner, Polar Capital Corporation (private investment firm). Chairman of Veresen Inc. since May 12, 2011.

Name, Residence and Shareholdings	Director Since	Veresen Position (if applicable) and Principal Occupation During Five Preceding Years
Henry W. Sykes [(2)(4)(7)] Calgary, Alberta, Canada 16,000 Common Shares held	January 17, 2011	Corporate director since November 2014; prior thereto President of MGM Energy Corp. (public oil and gas company) from January 2007 to June 2014 and Executive Chair of Parallel Energy Trust (public energy trust) until November 2014.
Bertrand A. Valdman [(1)(2)] Medina, Washington, U.S.A. 7,241 Common Shares held	July 3, 2008	President and Chief Executive Officer of Optimum Energy (private company specializing in data-driven cooling and heating optimization solutions) since February 2015; prior thereto Chief Strategy Officer of Edison International (public electric power generator, developer and distributor) from March 2011 to February 2015.
Thierry Vandal [(1)(4)] New York, New York, USA 3,230 Common Shares held	May 6, 2015	President of Axium Infrastructure US Inc. since August 2015 (private infrastructure investment firm); prior thereto President and Chief Executive Officer of Hydro-Québec from 2005 to May 2015.
Executive Officers		
Don L. Althoff Calgary, Alberta, Canada 66,398 Common Shares held	November 8, 2012	President and Chief Executive Officer of Veresen Inc. since November 2012; prior thereto Chief Executive Officer of Flex Fuels US LLC (an ethanol conversion system company) from October 2008 to September 2012.
Paul Eastman Toronto, Ontario, Canada 4,767 Common Shares held	N/A	Senior Vice President, Operations of Veresen Inc. since October 2015; prior thereto Vice President, Operations of Veresen Inc. from June 2014 to October 2015; prior thereto Vice President, Power Operations from June 2008 to June 2014.
Theresa Jang Calgary, Alberta, Canada 32,427 Common Shares held [(8)]	N/A	Senior Vice President Finance and Chief Financial Officer since June 2014; prior thereto Vice President, Finance and Risk Management and Interim Chief Financial Officer of Veresen Inc. from February 2014 to June 2014; prior thereto Vice President, Finance and Risk Management of Veresen Inc. from March 2013 to February 2014; and prior thereto Vice President, Controller of Veresen Inc. from September 2009 to March 2013.
Kevan S. King Calgary, Alberta, Canada 18,085 Common Shares held	N/A	Senior Vice President, General Counsel of Veresen Inc. since June 2014; prior thereto Senior Vice President, General Counsel and Secretary of Veresen Inc. from March 2011 to June 2014.
Jesse Marble Calgary, Alberta, Canada 20,298 Common Shares held	N/A	Senior Vice President, Corporate Development and Strategy since February 2015; prior thereto Vice President, Strategic Planning of Veresen Inc. from February 2014 to February 2015; and prior thereto Vice President, Financial and Business Analysis of Veresen Inc. from June 2010 to February 2014.
Darren Marine [(9)] Calgary, Alberta, Canada No Common Shares held	N/A	Senior Vice President, Business Joint Ventures of Veresen Inc. since February 2014; prior thereto private consultant to the midstream industry from January 2011 to February 2014.

Name, Residence and Shareholdings	Director Since	Veresen Position (if applicable) and Principal Occupation During Five Preceding Years
Elizabeth Spomer Houston, Texas, USA 10,000 Common Shares held	N/A	Executive Vice President, President & CEO, Jordan Cove LNG of Veresen Inc. since November 2014; prior thereto Senior Vice President, Global Business Development of BG Group PLC (an international exploration and production and LNG company) from January 2012 to October 2014; and prior thereto Senior Vice President, Business Development, Americas and Global LNG Region of BG Group PLC from 2004 to 2011.
Pam Ramotowski Calgary, Alberta, Canada 567 Common Shares held(10)	N/A	Vice President, Human Resources and Administration of Veresen Inc. since September 2014; prior thereto Vice President, People Services of SMART Technologies (a public technology company) from February 2012 to September 2014; and prior thereto Director, Total Compensation and Employee Relations of SMART Technologies from March 2008 to February 2012.

Notes:

(1) Member of the Audit Committee.

(2) Member of the Human Resources and Compensation Committee.

(3) Member of the Corporate Governance and Nominating Committee.

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

(5) 600 of the Common Shares are held by Mr. Iverach's wife in accounts over which Mr. Iverach exercises control or direction.

(6) Mr. Mulherin was a director of Impax Energy Services Income Trust from September 26, 2008 to December 22, 2008. Almost a full year later, on December 14, 2009, Impax obtained an order from the Alberta Court of Queen's Bench for creditor protection pursuant to the *Companies' Creditors Arrangement Act*.

(7) Mr. Sykes was a director of Parallel Energy Trust from March 2011 until February 2016. On November 9, 2015, Parallel Energy Trust filed an application in the Alberta Court of Queen's Bench of Calgary for protection pursuant to the *Companies' Creditors Arrangement Act*.

(8) 17,950 of the Common Shares are held by Ms. Jang's husband in accounts over which Ms. Jang exercises control or direction.

(9) Mr. Marine was an officer of SemCAMS ULC from September 2005 to February 2011. SemCAMS ULC obtained an order from the Alberta Court of Queen's Bench on July 30, 2008 for creditor protection pursuant to the *Companies' Creditors Arrangement Act.*

(10) 278 of the Common Shares are held by Ms. Ramotowski's husband in accounts over which Ms. Ramotowski exercises control or direction.

As at March 14, 2016, there were 303,096,627 Common Shares issued and outstanding. In addition, to the knowledge of management, our directors and executive officers, as a group, as at March 14, 2016, did not beneficially own, directly or indirectly, or exercise control or direction over, any Common Shares except as disclosed in the table above, which in aggregate represent less than 0.01% of the outstanding Common Shares.

AUDIT COMMITTEE INFORMATION

Terms of Reference of the Audit Committee

Appended to this Annual Information Form as Appendix "A" is a copy of our audit committee's terms of reference. The terms of reference is also available on our website at www.vereseninc.com.

Composition of the Audit Committee

The table below gives the identified information about each audit committee member.

Name	Independent	Financially Literate	Relevant Education and Experience
Maureen E. Howe	Yes	Yes	Ms. Howe has been a member of our audit committee since May 2012. Ms. Howe is formerly a Managing Director at RBC Capital Markets in equity research specializing in energy infrastructure, including power generation, transmission and distribution, oil and gas transmission and distribution, gas processing and alternative energy. Prior to joining RBC Capital Markets Ms. Howe held finance positions in the utility industry, investment banking and portfolio management. Ms. Howe has extensive experience in analyzing and evaluating financial statements and controls and procedures. She currently chairs an audit committee and an investment committee for other boards. Ms. Howe holds an undergraduate degree and a PhD in Business.
Rebecca McDonald	Yes	Yes	Ms. McDonald has been a member of our audit committee since May 2015. Ms. McDonald has more than 25 years' experience in the energy industry. Ms. McDonald has been responsible for the development, construction and operation of natural gas and liquids pipelines, gas and electricity distribution companies, as well as power plant and gas processing facilities in North America, Asia, Africa and South America. Prior to her retirement in 2012 Ms. McDonald served as Chief Executive Officer of Laurus Energy Inc. and prior thereto she has served as President of Gas and Power, GHP Bilton, Houston Museum of Natural Sciences and other organizations.
Bertrand A. Valdman (Chair)	Yes	Yes	Mr. Valdman has been a member of our audit committee since July 2008 and was appointed chair of the audit committee in March 2011. Mr. Valdman was an investment banker for 17 years and in that role originated and executed a broad range of public and private market financing and advisory assignments. He is currently the President and Chief Executive Officer of Optimum Energy. He has also served as the Chief Financial Officer of Puget Sound Energy, a New York Stock Exchange listed company and in that capacity, he was responsible for accounting, treasury, tax, risk management, investor relations and internal audit. Mr. Valdman also serves or has served on the finance committees and foundation boards of several private or not-for-profit organizations.
Thierry Vandal	Yes	Yes	Mr. Vandal has been a member of our audit committee since May 2015. Mr. Vandal is President and Chief Executive Officer of a private infrastructure firm and prior thereto served as President and Chief Executive Officer of Hydro-Québec for ten years and served in various other leadership roles at Hydro-Québec since 1996. Mr. Vandal was Chairman of the Board of the Société d'énergie de la Baie James and Hydro-Québec International until May 2015. He sits on the boards of the Royal Bank of Canada, HEC Montréal and McGill University, where he also serves as Chair of the Finance Committee. He is also a past Chairman of the Conference Board of Canada and of BioFuelNet Canada. Mr. Vandal holds an engineering degree from École Polytechnique (Université de Montréal) and an MBA in finance from HEC Montréal (Université de Montréal). In 2007, the Université de Montréal awarded him an honorary doctorate to underscore his outstanding professional contribution to the energy sector.

Pre-Approval Policies and Procedures

We have adopted a policy with respect to the pre-approval of audit and non-audit services to be provided by our auditors, PricewaterhouseCoopers LLP, and its related entities and those services that the auditors may not provide.

The policy provides that the audit of our annual financial statements is to be specifically approved annually by the signing of an audit engagement letter with our auditors. Other engagements of the auditors involving a specified list of services are subject to pre-approval by our audit committee. Management decides if a particular service is covered by this list of services. The list itself is reviewed, and if thought appropriate, approved on an annual basis by our audit committee.

Any engagement of our auditors involving a service not within the specified list of services, or where the fees for the engagement are expected to exceed $50,000, must be submitted to our audit committee for pre-approval. The Chair of our audit committee has the authority to effect any pre-approval, on behalf of our audit committee, provided the aggregate fees for all such services does not exceed $50,000. Any pre-approval by the Chair of our audit committee must be presented to our audit committee at the first scheduled meeting of our audit committee following such approval.

At every regularly scheduled meeting of our audit committee, management reports on all new pre-approved engagements of our auditors since the last such report.

External Auditor Service Fees

The following table sets forth the aggregate fees (in $ millions) we have paid to PricewaterhouseCoopers LLP in each of the last two fiscal years.

	2015	**2014**
Audit Fees	$0.9	$0.8
Audit-Related Fees	-	-
Tax Fees	-	-
All Other Fees [(1)]	$0.1	$0.3
Total [(2)]	$1.0	$1.1

Notes:

(1) All Other Fees include costs associated with the translation of financial statements and prospectuses and, for 2014, with enterprise risk management functions.

(2) PricewaterhouseCoopers LLP is the auditor of each of Alliance and Aux Sable. Alliance paid PricewaterhouseCoopers LLP fees of $0.6 million in 2015 and $0.8 million 2014. Aux Sable paid PricewaterhouseCoopers LLP fees of $0.5 million in 2015 and $0.4 million in 2014. These amounts are not included in the table above.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

No director or executive officer or any person who beneficially owns, or controls or directs, directly or indirectly, more than 10% of the outstanding Common Shares, or any associate or affiliate of any of these people, has had any material interest, direct or indirect, in any transaction within our three most recently completed financial years or during our current financial year which has materially affected, or is reasonably expected to materially affect us.

TRANSFER AGENT AND REGISTRAR

Our registrar and transfer agent for each of the Common Shares, Series A Preferred Shares, Series C Preferred Shares and Series E Preferred Shares is Computershare Trust Company of Canada at its principal offices in Calgary and Toronto.

MATERIAL CONTRACTS

Veresen Inc., or one or more of its subsidiary partnerships or corporations, or one or more of its operating entities have signed the following material contracts that are in effect as at the date of this Annual Information Form:

(a) the amended and restated common agreement dated as of May 16, 2003 among Alliance Canada, Alliance US and various lenders, agents and lenders' representatives from time to time party thereto, which sets out common provisions regarding the senior debt financing for Alliance Canada and Alliance US;

(b) the note purchase agreement dated May 4, 2005 pursuant to which Alberta Ethane Gathering System L.P., an indirect subsidiary partnership of ours, sold $110 million aggregate principal amount of senior unsecured notes due May 4, 2020 to institutional investors in Canada on a private placement basis;

(c) the trust indenture dated November 22, 2011 between us and Computershare Trust Company of Canada, as trustee, providing for the creation and issuance of medium term notes, including our medium term notes, Series 1;

(d) the first supplemental indenture dated March 14, 2012 between us and Computershare Trust Company of Canada, as trustee, providing for the creation and issuance of our medium term notes, Series 2 and Series 3;

(e) the second supplemental indenture dated June 13, 2014 between us and Computershare Trust Company of Canada, as trustee, providing for the creation and issuance of our medium term notes, Series 4; and

(f) the Shareholder Rights Plan Agreement between us and Computershare Trust Company of Canada, as rights agent, dated May 6, 2014.

EXPERTS

PricewaterhouseCoopers LLP, Chartered Accountants, is our auditor and such firm has prepared a report with respect to our consolidated financial statements as at and for the year ended December 31, 2015.

PricewaterhouseCoopers LLP has confirmed that it is independent in accordance with the relevant rules and related interpretation prescribed by the Institute of Chartered Accountants of Alberta.

APPENDIX "A"

DEFINED TERMS

AEGS	Alberta Ethane Gathering System
Alliance	Alliance Canada and Alliance US
Alliance Canada	Alliance Pipeline Limited Partnership
Alliance Canada Marketing	Alliance Canada Marketing L.P.
Alliance Canada Pipeline	That portion of the Alliance Pipeline that is located in Canada
Alliance Pipeline	A natural gas transmission pipeline that runs from northwestern Alberta and northeastern British Columbia to Channahon, Illinois
Alliance US	Alliance Pipeline L.P.
Alliance US Pipeline	That portion of the Alliance Pipeline that is located in the US
AOS	Authorized overrun service on the Alliance Pipeline
Aux Sable	Aux Sable Canada, Aux Sable US and Alliance Canada Marketing
Aux Sable Canada	Aux Sable Canada LP
Aux Sable Midstream	Aux Sable Midstream LLC
Aux Sable US	Aux Sable Liquid Products LP, Aux Sable Extraction LP and Aux Sable Midstream
Common Shares	Common Shares of Veresen Inc.
CRP	Cutbank Ridge Partnership, a partnership between Encana Corporation and Cutbank Dawson Gas Resources Ltd., a subsidiary of Mitsubishi Corporation
EHS	Environmental, Health and Safety
FERC	US Federal Energy Regulatory Commission
Jordan Cove	Jordan Cove Energy Project L.P.
IESO	Ontario Independent Electricity System Operator
MD&A	Management's Discussion and Analysis
NEB	National Energy Board
NRGreen	NRGreen Power Limited Partnership
Preferred Shares	Preferred Shares of Veresen Inc.
Ruby Pipeline	A natural gas transmission pipeline that runs from the Opal hub in Wyoming to the Malin hub in Oregon
SCADA	Supervisory control and data acquisition
SEDAR	System for Electronic Document Analysis and Retrieval
Series A Preferred Shares	Cumulative Redeemable Series A Preferred Shares of Veresen Inc.
Series B Preferred Shares	Cumulative Redeemable Series B Preferred Shares of Veresen Inc.
Series C Preferred Shares	Cumulative Redeemable Series C Preferred Shares of Veresen Inc.
Series D Preferred Shares	Cumulative Redeemable Series D Preferred Shares of Veresen Inc.
Series E Preferred Shares	Cumulative Redeemable Series E Preferred Shares of Veresen Inc.
Series F Preferred Shares	Cumulative Redeemable Series F Preferred Shares of Veresen Inc.
Shareholders	Holders of Common Shares
SMART	Sustainability Management and Reporting Tool
Veresen Midstream	Veresen Midstream Limited Partnership, a limited partnership owned by a wholly-owned subsidiary of Veresen Inc. and affiliates of Kohlberg Kravis Roberts & Co. L.P.

TECHNICAL ABBREVIATIONS

bbls	=	barrels (42 US gallons)	km	=	kilometer
bbls/d	=	barrels per day	mdth/d	=	thousand decatherms per day
bcf/d	=	billion cubic feet per day	mmcf/d	=	million cubic feet per day
btu/cf	=	British thermal unit per one cubic foot	mcf	=	thousand cubic feet
th/d		decatherms per day	mtpa	=	million tons per annum
hp	=	horsepower	MW	=	megawatt

INDUSTRY TERMS

This is a glossary of certain industry terms used in this Annual Information Form:

cogeneration	generation of electricity and the capture and use of otherwise wasted heat energy byproducts; cogeneration is also referred to as a combined heat and power system
downstream	processes or other activities, such as refining or marketing, that occur after a product leaves a facility
firm transportation	pipeline service that is available at all times during a period covered by a transportation contract; also, the service is not subject to a prior claim from another customer and receives the same priority as any other customer having a right to firm transportation
GHG	greenhouse gas
greenfield	a project or development that is originally conceived and executed where no assets or operations exist
LNG	liquefied natural gas
NGL	those hydrocarbon components that can be recovered from natural gas as liquids including ethane, propane, butanes, pentanes plus and condensate
shipper	a company that holds a contract to transport natural gas, and NGL, if applicable, on a pipeline
straddle plant	a gas processing plant located on or near a gas pipeline which removes NGL from gas and returns the gas to the pipeline
WCSB	Western Canadian Sedimentary Basin

APPENDIX "B"

TERMS OF REFERENCE OF THE AUDIT COMMITTEE

1. Establishment of Audit Committee: The board of directors (the "Board") of Veresen Inc. (the "Company") hereby establishes a committee to be called the Audit Committee.

2. Composition of Audit Committee: The membership of the Audit Committee shall be as follows:

(a) The Audit Committee shall be composed of not less than three members or such greater number as the Board may from time to time determine. At least one quarter of the members of the Audit Committee shall be resident Canadians.

(b) All members of the Audit Committee shall be independent within the meaning set forth under Multilateral Instrument 52-110 Audit Committees as amended from time to time (MI 52-110). Currently, a member of the Audit Committee is independent if the member has no direct or indirect material relationship with the Company. A "material relationship" means a relationship which could, in the view of the Board, reasonably interfere with the exercise of a member's independent judgment.

(c) Each member of the Audit Committee shall be financially literate within the meaning set forth under MI 52-110. Currently, "financially literate" means the ability to read and understand a set of financial statements that present a breadth and level of complexity of accounting issues that are generally comparable to the breadth and complexity of the issues that can reasonably be expected to be raised by the Company's financial statements. An Audit Committee member who is not financially literate may be appointed to the Audit Committee provided that the member becomes financially literate within a reasonable period of time following his or her appointment.

(d) Members shall be appointed annually by the Board from among directors of the Company. The Chair of the Audit Committee shall be appointed by the Board. A member of the Audit Committee shall *ipso facto* cease to be a member of the Audit Committee upon ceasing to be a director of the Company.

3. Relationship with External Auditors: The Audit Committee shall advise the external auditors of their accountability to the Audit Committee and the Board as representatives of the Company and its shareholders to whom the external auditors are ultimately accountable. The external auditors of the Company shall report directly to the Audit Committee.

4. Duties and Responsibilities of Audit Committee: Subject to the powers and duties of the Board and in addition to any other duties and responsibilities assigned to the Audit Committee from time to time by the Board, the Audit Committee shall have the following duties and responsibilities:

Assessment of Independence and Financial Literacy

(a) At least annually reviewing and assessing the independence and financial literacy of its members and for determining whether or not new members are independent and financially literate.

Financial Statements and Other Financial Information

(b) The primary responsibility of the Audit Committee shall be to assist the Board in the proper discharge of its duties and responsibilities to the Company relating to the review of:

(i) the Company's financial statements;

(ii) any other financial information relating to the Company to be provided to shareholders; and

(iii) all audit processes.

The Audit Committee shall also be responsible for ensuring its compliance with all of the applicable requirements of MI 52-110 and for reporting any non-compliance with such requirements to the Board including the reasons for such non-compliance.

(c) The Audit Committee shall be responsible for reviewing the Company's financial statements, management's discussion and analysis and annual and interim earnings press releases before the Company publicly discloses this information. The Audit Committee shall recommend for approval to the Board the Company's audited annual financial statements, related management's discussion and analysis and annual earnings press releases. The Audit Committee shall approve on behalf of the Board the Company's interim financial statements and related management's discussion and analysis and interim earnings press releases.

(d) The Audit Committee shall be responsible for ensuring that adequate procedures are in place for the review of the Company's public disclosure of financial information extracted or derived from the Company's financial statements, other than the public disclosure referred to in paragraph (b) above and must periodically assess the adequacy of those procedures.

(e) The Audit Committee shall be responsible for establishing procedures for:

(i) the receipt, retention and treatment of complaints received by the Company regarding accounting, internal accounting controls or auditing matters; and

(ii) the confidential, anonymous submission by employees of the Company of concerns regarding questionable accounting or auditing matters.

(f) The Audit Committee shall review with the external auditors and management of the Company:

(i) the scope of the audit;

(ii) significant changes to the Company's accounting principles, practices or policies;

(iii) new or pending developments in accounting principles, reporting matters or industry practices which may materially affect the Company; and

(iv) the quality of the Company's accounting principles, practices or policies as applied in the Company's financial statements in terms of disclosure quality and evaluation methods, including the degree of conservatism or aggressiveness of such accounting principles, practices or policies and the underlying estimates and other significant decisions made by management in preparing the Company's financial statements.

(g) The Audit Committee shall review with the external auditors and management of the Company the results of the annual audit, and make appropriate recommendations to the Board having regard to, among other things:

(i) the financial statements;

(ii) management's discussion and analysis and related financial disclosure contained in continuous disclosure documents;

(iii) significant changes, if any, to the initial audit plan;

(iv) accounting and reporting decisions relating to significant current year events and transactions;

(v) the management letter, if any, outlining the external auditors' findings and recommendations, together with management's response, with respect to internal controls and accounting procedures; and

(vi) any other matters relating to the conduct of the audit, including such other matters which should be communicated to the Audit Committee under generally accepted auditing standards.

(h) The Audit Committee shall review with management and, if deemed necessary by the Audit Committee, the external auditors of the Company, the interim financial statements and any other matters relating thereto.

Adoption of Formal Written Charter

(i) The Audit Committee shall be responsible for adopting a formal written charter which sets out its mandate and responsibilities. The charter must be approved by the Board. The Audit Committee shall review and assess the adequacy of the charter on an annual basis and recommend for approval to the Board any amendments thereto.

External Auditors

(j) The Audit Committee must recommend to the Board:

(i) the external auditors to be nominated for the purpose of preparing or issuing an auditor's report or performing other audit, review or attest services for the Company; and

(ii) the compensation of the external auditors.

(k) The Audit Committee shall be directly responsible for overseeing the work of the external auditors engaged for the purpose of preparing or issuing an auditor's report or performing other audit, review or attest services for the Company, including the resolution of disagreements between management and the external auditors regarding financial reporting.

Pre-Approval of Non-Audit Services

(l) The Audit Committee shall be responsible for pre-approving all non-audit services to be provided to the Company or its subsidiary entities by the Company's external auditors. The Audit Committee shall adopt specific policies and procedures for the engagement of non-audit services and any pre-approval policies and procedures shall be detailed as to the particular service and require that the Audit Committee be informed of each non-audit service. Such policies and procedures shall not include delegation of the Audit Committee's responsibilities to management of the Company. The Audit Committee may delegate to one or more independent members the authority to pre-approve non-audit services. The pre-approval of non-audit services by any member of the Audit Committee to whom authority has been delegated must be presented to the Audit Committee at its first scheduled meeting following such pre-approval.

Reporting Obligations

(m) The Audit Committee shall be responsible for reviewing the disclosure contained in the Company's annual information form as required by Form 52-110F1 Audit Committee Information Required in an AIF attached to MI 52-110. If management of the Company solicits proxies from shareholders of the Company for the purpose of recommending persons to be elected as directors, the Audit Committee shall be responsible for ensuring that the Company's information circular includes a cross-reference to the sections in the Company's annual information form that contain the information required by Form 52-110F1.

Auditor Oversight and Independence

(n) The Audit Committee shall be responsible for:

(i) ensuring compliance by the Company's external auditors with the requirements set forth in National Instrument 52-108 Auditor Oversight;

(ii) ensuring that the Company's external auditors are participants in good standing with the Canadian Public Accountability Board (CPAB) and participate in the oversight programs established by the CPAB from time to time and that the external auditors have complied with any restrictions or sanctions imposed by the CPAB as of the date of the applicable auditor's report relating to the Company's annual audited financial statements; and

(iii) obtaining from the external auditors of the Company a formal written statement describing in detail all of the relationships between the external auditors and the Company, determining whether the non-audit services performed by the external auditors during the year have impacted their independence, ensuring that no relationship between the external auditors and the Company exists which may

affect the independence of the external auditors and taking appropriate action to ensure the independence of the external auditors.

Authority of the Audit Committee

(o) The Audit Committee shall have the authority:

(i) to engage independent counsel and other advisors as it determines necessary to carry out its duties;

(ii) to set and pay the compensation for any advisors employed by the Audit Committee; and

(iii) to communicate directly with the internal (if any) and external auditors of the Company.

Internal Controls, Information Systems and Risk Management

(p) The Audit Committee shall review at least annually:

(i) with the external auditors of the Company the adequacy of internal control procedures and management information systems and make inquiries to management and the external auditors of the Company about significant risks and exposures to the Company that may have a material adverse impact on the Company's financial statements and about the efforts of the management of the Company to mitigate such risks and exposures;

(ii) the Company's method of reviewing major risks inherent in the Company's businesses, facilities and strategic directions, including the Company's risk management and evaluation process;

(iii) the strategies and practices applicable to the Company's assessment, management, prevention and mitigation of risks (including the foreign currency and interest rate risk strategies, counterparty credit exposure, the use of derivative instruments, insurance and adequacy of tax provisions); and

(iv) the loss prevention policies, risk management programs and disaster response and recovery programs of the Company.

(q) The Audit Committee shall assess and make recommendations to the Board in respect of the development of guidelines for the insurance and indemnification of officers and directors of the Company and such actions as may be appropriate to defend, indemnify and save harmless the officers and directors of the Company to the extent permitted under the by-laws of the Company.

Supervision of Certification of Annual Filings and Interim Filings

(r) The Audit Committee shall be responsible for supervising the preparation and filing of each annual certificate in Form 52-109F1 and each interim certificate in Form 52-109F2 to be signed by the Chief Executive Officer and Chief Financial Officer of the Company in accordance with the requirements set forth under Multilateral Instrument 52-109

Certification of Disclosure in Issuers' Annual and Interim Filings as amended from time to time (MI 52-109). These certificates require the Chief Executive Officer and the Chief Financial Officer to certify, among other things, that, based on their knowledge:

(i) the annual filings and interim filings do not contain any untrue statement of a material fact or omit to state a material fact required to be stated or that is necessary to make a statement not misleading in light of the circumstances under which it was made with respect to the period covered by the annual filings or interim filings; and

(ii) the annual financial statements and the interim financial statements of the Company, together with the other financial information included in the annual filings or interim filings, fairly present in all material respects the financial condition, results of operations and cash flows of the Company as of the date and for the periods presented in the annual filings or interim filings.

(s) The Audit Committee is responsible for ensuring that management of the Company establishes and maintains disclosure controls and procedures for the Company that are designed to provide reasonable assurance that material information relating to the Company, including its consolidated subsidiaries, is made known to management of the Company by others within those entities, particularly during the period in which the annual filings or interim filings are being prepared and that management of the Company establishes and maintains internal control over financial reporting for the Company that has been designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with the Company's generally accepted accounting principles. In respect of annual filings only, the Audit Committee is also responsible for ensuring that management of the Company evaluates the effectiveness of the Company's disclosure controls and procedures as of the end of the period covered by the annual filings and has caused the Company to disclose in the annual management's discussion and analysis its conclusions about the effectiveness of the disclosure controls and procedures as of the end of the period covered by the annual filings based on such evaluation. The terms "annual filings," "interim filings," "disclosure controls and procedures" and "internal control over financial reporting" shall have the meanings set forth under MI 52-109.

(t) The Audit Committee is also responsible for monitoring any changes in the Company's internal control over financial reporting and for ensuring that any change that occurred during the Company's most recent interim period that has materially affected, or is reasonably likely to materially affect, the Company's internal control over financial reporting is disclosed in the Company's annual management's discussion and analysis.

Litigation, Legal and Regulatory Matters

(u) The Audit committee shall review with management of the Company, the external auditors and, if necessary, legal counsel, any litigation, claim or contingency, including tax assessments, that could have a material effect upon the financial position of the Company, and the manner in which these matters have been disclosed in the financial statements.

(v) Review with management the Company's compliance policies, legal matters and any material reports or inquiries received from regulators or governmental agencies that could

have a material effect upon the financial position of the Company and which are not subject to the oversight of another committee of the Board.

Other

(w) The Audit Committee must review and approve the Company's hiring policies regarding partners, employees and former partners and employees of the present and former external auditors of the Company.

(x) The Audit Committee shall monitor policies and procedures relating to directors' and officers' expenses and the reimbursement thereof and relating to any perquisites paid to directors and officers.

(y) The Audit Committee shall receive reports from the Disclosure Policy Committee pursuant to the Disclosure Policy of the Company.

(z) The Audit Committee shall conduct regular assessments to evaluate the effectiveness and contributions of the individual members of the Audit Committee and the committee as a whole.

5. Administrative Matters: The following general provisions shall have application to the Audit Committee:

(a) A quorum of the Audit Committee shall be the attendance of a majority of members thereof present in person or by telephone. No business may be transacted by the Audit Committee except at a meeting of its members at which a quorum of the Audit Committee is present or by a resolution in writing signed by all the members of the Audit Committee. Meetings of the Audit Committee shall be held at least quarterly and more often as the Chair of the Audit Committee may determine or upon the request of the Board, a member of the Audit Committee, an officer of the Company or the external auditors of the Company. The Audit Committee shall meet separately at each meeting without management (including any member of management who is a Board member) present.

(b) Any member of the Audit Committee may be removed or replaced at any time by resolution of the Board. The Board, upon recommendation of the Corporate Governance and Nominating Committee, may fill vacancies on the Audit Committee by appointment from among the members of the Board. If and whenever a vacancy shall exist on the Audit Committee, the remaining members may exercise all its powers so long as a quorum remains. Subject to the foregoing, each member of the Audit Committee shall hold such office until the close of the annual meeting of shareholders of the Company next following the date of appointment as a member of the Audit Committee or until a successor is duly appointed. Any member of the Board who has served as a member of the Audit Committee may be re-appointed as a member of the Audit Committee following the expiration of his or her term.

(c) The Audit Committee may invite such officers, directors and employees of the Company and its subsidiary entities as it may see fit from time to time to attend at meetings of the Audit Committee and to assist thereat in the discussion of matters being considered by the Audit Committee. The external auditors of the Company shall appear before the Audit Committee when requested to do so by the Audit Committee. The Audit

Committee shall meet with the external auditors of the Company independent of management of the Company at least annually and at such other times as the Chair of the Audit Committee may determine or upon the request of a member of the Audit Committee or the external auditors of the Company.

(d) The time at which and the place where the meetings of the Audit Committee shall be held, the calling of meetings and the procedure at such meetings shall be determined by the Audit Committee, having regard to the by-laws of the Company. Notice of each meeting of the Audit Committee shall be given to each member of the Audit Committee and to the external auditors of the Company who shall be entitled to attend and to be heard at each meeting of the Audit Committee. A meeting of the Audit Committee may be held at any time without notice if all of the members are present or, if any members are absent, those absent have waived notice or otherwise signified their consent in writing to the meeting being held in their absence.

(e) The Chair shall preside at all meetings of the Audit Committee. In the absence of the Chair, the other members of the Audit Committee shall appoint one of their members to act as Chair for the particular meeting.

(f) The Audit Committee shall report to the Board on such matters and questions relating to the financial position of the Company and its subsidiary entities as the Board may from time to time refer to the Audit Committee.

(g) The members of the Audit Committee shall, for the purpose of performing their duties, have the right to inspect all the books and records of the Company and its subsidiary entities and to discuss such books and records that are in any way related to the financial position of the Company and its subsidiary entities with the officers, directors and employees of the Company and its subsidiary entities and with the external auditor of the Company.

(h) The Chair of each meeting of the Audit Committee shall appoint a person to act as recording secretary to keep the minutes of the meeting. The recording secretary need not be a member of the Audit Committee.

(i) Minutes of the Audit Committee will be recorded and maintained and signed by the Chair and the recording secretary of the meeting. The Chair of the Audit Committee will report to the Board on the activities of the Audit Committee and/or the minutes will promptly be circulated to the members of the Board who are not members of the Audit Committee or otherwise made available at the next meeting of the Board.

(j) The Audit Committee shall have the authority to engage outside consultants and advisors as it determines necessary to carry out its duties. The Company shall provide appropriate funding to compensate any such consultant or advisor, as determined by the Audit Committee in its capacity as a committee of the Board.