COURT FILE NUMBER	1601-12571
COURT	COURT OF QUEEN'S BENCH OF ALBERTA
JUDICIAL CENTRE	CALGARY
	IN THE MATTER OF THE *COMPANIES' CREDITORS ARRANGEMENT ACT*, R.S.C. 1985, c. C-36, as amended
	AND IN THE MATTER OF A PLAN OF COMPROMISE OR ARRANGEMENT OF LIGHTSTREAM RESOURCES LTD, 1863359 ALBERTA LTD, LTS RESOURCES PARTNERSHIP, 1863360 ALBERTA LTD AND BAKKEN RESOURCES PARTNERSHIP
DOCUMENT	**EXHIBITS TO THE QUESTIONING OF PETER D. SCOTT HELD OCTOBER 3, 2016**
ADDRESS FOR SERVICE AND CONTACT INFORMATION OF PARTY FILING THIS DOCUMENT	**BENNETT JONES LLP** Barristers and Solicitors 4500, 855 – 2nd Street SW Calgary, Alberta T2P 4K7 Attention: Chris Simard Telephone No.: 403-298-4485 Fax No.: 403-265-7219 Client File No.: 76443.1

ANNUAL INFORMATION FORM
FOR THE YEAR ENDED DECEMBER 31, 2015

March 30, 2016

EXHIBIT 1 DATE Oct 3/16

WITNESS P. D. Scott

HEATHER BOWIE
COURT REPORTER

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DEFINITIONS

In this Annual Information Form, the capitalized terms set forth below have the following meanings:

ABCA means the *Business Corporations Act* (Alberta), R.S.A. 2000, c. B-9, as amended, together with all regulations promulgated thereunder;

Board means the Board of Directors of Lightstream;

COGE Handbook means the Canadian Oil and Gas Evaluation Handbook as amended from time to time maintained by the Society of Petroleum Evaluation Engineers (Calgary Chapter);

Common Shares means the common shares of the Company;

Company, Lightstream, we or **us** means Lightstream Resources Ltd. and, where applicable, our subsidiaries and affiliates, including our interests in joint ventures and partnerships;

Convertible Notes means the 3.125% convertible notes of the Company that matured on February 8, 2016;

Credit Facility means the secured termed credit facility of the Company;

CSA 51-324 means Staff Notice 51-324 – *Glossary to NI 51-101 Standards of Disclosure for Oil and Gas Activities* of the Canadian Securities Administrators;

GAAP means Canadian generally accepted accounting principles, which incorporates IFRS for the year beginning January 1, 2011;

Gross means: (a) in relation to the Company's interest in production and reserves, our working interest (operating and non-operating) share before deduction of royalties and without including any royalty interest of the Company; (b) in relation to wells, the total number of wells in which the Company has an interest; and (c) in relation to properties, the total area of properties in which the Company has an interest;

IFRS means International Financial Reporting Standards;

NCIB means normal course issuer bid;

Net means: (a) in relation to the Company's interest in production and reserves, our working interest (operating and non-operating) share after deduction of royalty obligations, plus the Company's royalty interest in production or reserves; (b) in relation to wells, the number of wells obtained by aggregating the Company's working interest in each of our gross wells; and (c) in relation to the Company's interest in a property, the total area in which the Company has an interest multiplied by the working interest owned by the Company;

New Petrobank means the company incorporated under the ABCA that is currently called Touchstone Exploration Inc.;

NI 51-101 means National Instrument 51-101 - *Standards of Disclosure for Oil and Gas Activities* of the Canadian Securities Administrators;

Old Petrobank means the company incorporated under the ABCA and formerly called Petrobank Energy and Resources Ltd. that amalgamated with the Company on December 31, 2012;

Petrobank Reorganization means the series of transactions completed on December 31, 2012 under a plan of arrangement under the ABCA between the Company, Old Petrobank and New Petrobank pursuant to which, among other things, (a) Old Petrobank transferred its existing heavy oil business to New Petrobank and distributed the shares of New Petrobank to its shareholders, and (b) the Company and Old Petrobank amalgamated, with the amalgamated company continuing under the name "PetroBakken Energy Ltd.", (c) each shareholder of Old Petrobank received 1.1051 Common Shares for each Old Petrobank share held immediately prior to the reorganization, and (d) each shareholder of the Company received one Common Share for each Class A Share of the Company held immediately prior to the reorganization;

Secured Note Indenture means the note indenture dated July 2, 2015 between the Company, our material subsidiaries, U.S. National Bank Association and Computershare Trust Company of Canada governing the Secured Notes;

Secured Notes means the second priority senior secured notes of the Company issued pursuant to the Secured Note Indenture;

Shareholder Rights Plan means the shareholder rights plan of the Company dated November 19, 2012 and effective January 1, 2013 as described under *"Capital Structure –Shareholder Rights Plan"*;

Sproule means Sproule Associates Limited, independent petroleum engineers, of Calgary, Alberta, Canada;

Sproule Report means the independent engineering evaluation of the Company's crude oil and natural gas reserves in Canada prepared by Sproule, dated February 9, 2016, with an effective date of December 31, 2015;

TSX means the Toronto Stock Exchange;

Unsecured Note Indenture means the note indenture dated January 30, 2012 between the Company, U.S. National Bank Association and Computershare Trust Company of Canada governing the Unsecured Notes; and

Unsecured Notes means the senior unsecured notes of the Company issued pursuant to the Unsecured Note Indenture.

ABBREVIATIONS

Oil and Natural Gas Liquids		Natural Gas	
bbl	Barrel	Mcf	Thousand cubic feet
bbl/d	Barrels per day	Mcf/d	Thousand cubic feet per day
Mbbls	Thousand barrels	MMcf	Million cubic feet
BOE or boe	Barrels of oil equivalent	MMcf/d	Million cubic feet per day
boe/d or boepd	Barrels of oil equivalent per day	MMBtu	Million Metric British Thermal Units
Mboe	1,000 barrels of oil equivalent	m^3	Cubic metre
NGL	Natural gas liquids	10^3m^3	Thousands of cubic metres
P+P	Proved plus probable	GJ	Gigajoule

Other

AECO	a natural gas storage facility located at Suffield, Alberta
API	American Petroleum Institute
°API	an indication of the specific gravity of crude oil measured on the API gravity scale. Liquid petroleum with a specified gravity of 28° API or higher is generally referred to as light crude oil
WTI	West Texas Intermediate, the reference price paid in U.S. dollars at Cushing, Oklahoma for crude oil of standard grade
M$ or $000s	Thousands of Canadian dollars
US$	United States dollars

CONVENTIONS

Certain other terms used in this Annual Information Form but not otherwise defined herein shall have the same meanings as defined in NI 51-101 and CSA 51-324 unless the context otherwise requires.

We have adopted the standard of six Mcf to one bbl when converting natural gas to oil. Disclosure provided herein in respect of boes may be misleading, particularly if used in isolation. A boe conversion ratio of six Mcf to one bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent an economic value at the wellhead. Given that the value ratio based on the current price of crude oil as compared to natural gas is significantly different from the energy equivalency of 6:1, utilizing a conversion on a 6:1 basis may be misleading as an indication of value.

In this Annual Information Form, references to "dollars" and "$" are to the currency of Canada, unless otherwise indicated.

Unless the context otherwise requires, reference in this Annual Information Form to "Lightstream" or the "Company" are to Lightstream Resources Ltd., formerly PetroBakken Energy Ltd., and our subsidiaries and affiliates including interests in joint ventures and partnerships.

Unless otherwise noted, the Company's average daily production volumes disclosed herein are based on the Company's working interest production before deduction of royalties paid to others and including royalty volumes received. Estimated values of future net revenue disclosed in this Annual Information Form do not necessarily represent fair market values.

NOTICE TO READER

Special Note Regarding Forward-Looking Statements

Certain statements contained in this Annual Information Form constitute forward-looking statements. The Company believes the expectations reflected in those forward-looking statements are reasonable, but no assurance can be given that these expectations will prove to be correct. Accordingly, any such forward-looking statements are qualified in their entirety by reference to, and are accompanied by, the factors discussed throughout this Annual Information Form. Such forward-looking statements included in this Annual Information Form should not be unduly relied upon.

In particular, this Annual Information Form may contain forward-looking statements pertaining to the following:

- projections of market prices, foreign currency exchange rates and costs;
- supply and demand for oil and natural gas;
- planned capital expenditure programs and anticipated results thereof;
- free cash flow and debt levels;
- ability of the Company to complete asset dispositions at favourable metrics;
- the characteristics of the Company's oil and natural gas properties and anticipated future performance;
- oil and natural gas production levels;
- the size of the oil and natural gas reserves;
- the Company's plans for the development of our proved undeveloped reserves and probable undeveloped reserves;
- the anticipated means of funding future development costs;
- planned enhanced recovery programs and anticipated results thereof;
- expectations regarding the ability of the Company to continually add to reserves through acquisitions and development;
- treatment under governmental regulatory regimes and tax laws;

- anticipated costs of compliance with environmental laws and regulations;
- anticipated future abandonment and reclamation costs; and
- the Company's dividend policy.

In addition, statements relating to "reserves" or "resources" are deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions that the resources and reserves described can be profitably produced in the future.

With respect to forward-looking statements contained in this Annual Information Form, the Company has made assumptions regarding:

- general economic and financial market conditions and availability of capital;
- commodity prices;
- oil and natural gas production levels;
- timing and amount of capital expenditures;
- access to infrastructure for processing and marketing our production;
- availability of labour and drilling equipment and access to drilling locations;
- government regulation in the areas of taxation, royalty rates and environmental protection;
- the performance of existing wells and new wells; and
- our ability to obtain necessary regulatory approvals.

The Company believes the expectations and assumptions reflected in the forward-looking statements set forth herein are reasonable, but no assurance can be given that these expectations or assumptions will prove to be correct. Accordingly, any such forward-looking statements should not be unduly relied upon.

Actual results could differ materially from those anticipated in the forward-looking statements set forth herein as a result of the risk factors set forth below and elsewhere in this Annual Information Form:

- financial resources of the Company;
- volatility in market prices for oil, NGLs and natural gas;
- global economic conditions and the Company's ability to access equity and debt markets;
- fluctuations in foreign currency exchange rates;
- risks inherent in oil and natural gas operations (including operational risks in development, exploration and production, delays or changes in plans with respect to exploration or development projects or capital expenditures, the uncertainty of estimates and projections relating to production, costs and expenses, reliance on industry partners, availability of equipment and personnel, availability of third party infrastructure, and uncertainty surrounding timing for drilling and completion activities resulting from weather or access restrictions);
- uncertainties associated with estimating oil and natural gas reserves;
- unfavourable market for asset dispositions;
- competition for, among other things, capital and acquisitions of reserves and undeveloped lands;
- geological, technical, drilling and processing problems;
- the ability to economically test, develop and utilize new technologies;
- changes in legislation, including changes in environmental or tax laws, royalty rates or government incentive programs relating to the oil and gas industry; and
- the other factors discussed under the heading "*Risk Factors*".

Readers are cautioned that the foregoing lists of factors are not exhaustive. The forward-looking statements contained in this Annual Information Form are expressly qualified by this cautionary statement. Further, any forward-looking statement is made only as of a certain date, and the Company undertakes no obligation to update any forward-looking statement or statements to reflect events or circumstances after the date on which such statement is made or to reflect the occurrence of unanticipated events, except as may be required by applicable securities laws. New factors emerge from time to time, and it is not possible for management of the Company to predict all of these factors and to assess in advance the impact of each such factor on the Company's business or the extent to which any factor, or combination of factors, may cause actual results to differ materially from those contained in any forward-looking statement.

Non-GAAP Measures

This Annual Information Form contains financial terms that are not considered measures under GAAP, such as operating netback or funds flow from operations. These measures are commonly utilized in the oil and gas industry and are considered informative for management and stakeholders. Specifically, profitability relative to commodity prices per unit of production is demonstrated by an operating netback. Operating netback reflects revenues less royalties, transportation costs, and production expenses divided by production for the period. Funds flow from operations reflects cash generated from operating activities from continuing operations before changes in non-cash working capital. Operating netbacks and funds flow from operations do not have standardized meanings and therefore may not be comparable to those reported by other companies, nor should they be viewed as an alternative to cash flow from operations or other measures of financial performance calculated in accordance with GAAP.

Drilling Locations

This Annual Information Form discloses drilling locations in three categories: proved locations; probable locations; and unbooked locations. Proved locations and probable locations are sometimes collectively referred to as "booked locations", and are derived from Lightstream's most recent independent reserves evaluation and account for drilling locations that have associated proved plus probable reserves or probable-only reserves, as applicable. Unbooked locations as disclosed herein have been identified by management as an estimation of the Company's multi-year drilling activities using information including evaluation of applicable geologic, seismic, engineering, production, pricing assumptions and reserves information. The reserves and resources in the unbooked locations meet the classifications of possible reserves or contingent resources under the COGE Handbook. There is no certainty that Lightstream will drill any or all booked or unbooked drilling locations and, if drilled, there is no certainty that such locations will result in additional oil and gas reserves, resources or production.

CORPORATE STRUCTURE

Incorporation and Material Reorganizations

The Company was incorporated as PetroBakken Energy Ltd. under the ABCA on July 30, 2009.

The Company completed the Petrobank Reorganization on December 31, 2012, pursuant to which, among other things, it amalgamated with Old Petrobank under the ABCA with the resulting company continuing under the name PetroBakken Energy Ltd.

The Company amended our articles to change our name to Lightstream Resources Ltd. on May 22, 2013.

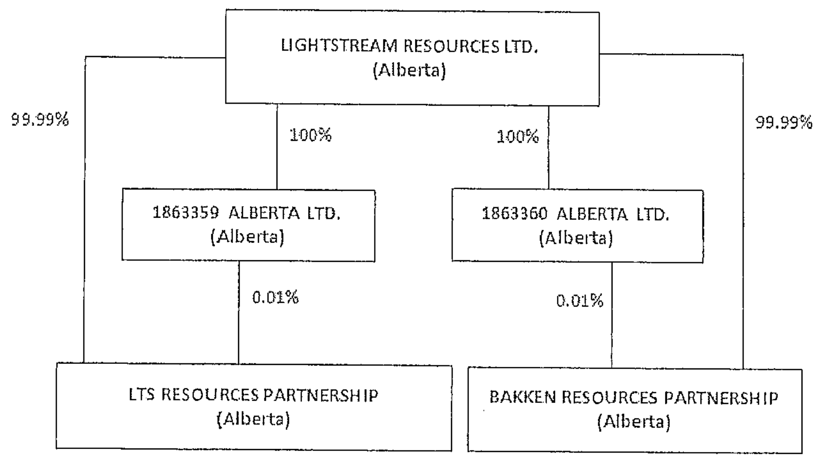
On January 2, 2015, the Company completed an internal reorganization whereby Lightstream Resources Partnership, a general partnership owned by the Company (99.9%) and Lightstream Capital Ltd. (0.1%), a wholly-owned subsidiary of the Company transferred (i) all of our assets located in Alberta and British Columbia to LTS Resources Partnership, a newly formed general partnership owned by the Company (99.99%) and 1863359 Alberta Ltd. (0.01%), a newly incorporated wholly-owned subsidiary of the Company, and (ii) all of our assets located in Saskatchewan to Bakken Resources Partnership, a newly formed general partnership owned by the Company (99.99%) and 1863360 Alberta Ltd. (0.01%), a newly incorporated wholly-owned subsidiary of the Company. Lightstream Resources Partnership and Lightstream Capital Ltd. were subsequently dissolved on January 2, 2015. The Company is the managing partner of both LTS Resources Partnership and Bakken Resources Partnership. See a diagram of our current structure under *"Our Organizational Structure"*.

The registered office of the Company is located at Suite 3300, 421 – 7th Avenue S.W., Calgary, Alberta T2P 4K9, and our head office is located at Suite 2800, 525 – 8th Avenue S.W., Calgary, Alberta T2P 1G1.

Our Organizational Structure

LTS Resources Partnership owns all of our oil and natural gas properties located in Alberta and British Columbia and is owned 100 per cent directly and indirectly by Lightstream Resources Ltd. Bakken Resources Partnership owns all of our oil and natural gas properties in Saskatchewan and is owned 100 per cent directly and indirectly by Lightstream Resources Ltd. Lightstream Resources Ltd. is the managing partner of LTS Resources Partnership and Bakken Resources Partnership. LTS Resources Partnership and Bakken Resources Partnership are partnerships formed under the laws of Alberta.

The following diagram sets forth our organizational structure as of the date hereof.



THREE-YEAR HISTORY OF THE BUSINESS

Year Ended December 31, 2013

In April 2013, the term of the Company's Credit Facility was extended to June 2016, with the same general terms and conditions.

At the Company's annual shareholder meeting held on May 22, 2013, shareholders approved the change of name of the Company from "PetroBakken Energy Ltd." to "Lightstream Resources Ltd." On May 28, 2013, the Common Shares of the Company began trading on the TSX under the new corporate name and under the new stock symbol "LTS".

In November 2013, we renewed our NCIB. In accordance with the renewed NCIB, Lightstream was authorized to repurchase up to 17,051,793 Common Shares from time to time until November 11, 2014. In 2013, we did not repurchase any Common Shares under our NCIB.

On November 21, 2013, Lightstream announced the termination of our dividend reinvestment plan and share dividend plan and the reduction of our dividend by 50% to $0.04 per month. These changes became effective for the December 2013 dividend paid in January 2014.

Year Ended December 31, 2014

In April 2014, the term of the Company's Credit Facility was extended to June 2017 and the lending amount was reduced by $100 million to $1.3 billion, to reflect asset dispositions that had occurred.

In 2014, we sold $729 million of non-core assets representing approximately 6,315 boepd of production (79% liquids) and 20.9 million boe of proved plus probable reserves through a number of transactions. The majority of the assets sold were non-core southeast Saskatchewan conventional assets, including two working interest asset sales and one royalty interest asset sale. The proceeds were used to reduce overall corporate debt.

Following the asset dispositions, on September 30, 2014 the maximum lending amount under our Credit Facility was reduced by $150 million to $1.15 billion (before the optional accordion feature that permitted an increase by a further $100 million).

In 2014, we repurchased US$100 million principal amount of outstanding Unsecured Notes in two separate transactions for an aggregate purchase price of US$97.7 million, including accrued interest. The repurchased Unsecured Notes were retired, leaving a total of US$800 million aggregate principal amount of Unsecured Notes outstanding.

In November 2014, we renewed our NCIB authorizing us to repurchase up to 19,182,776 Common Shares from time to time until November 11, 2015. In 2014, we repurchased 3.5 million Common Shares under our NCIB and returned them to treasury.

On December 15, 2014, in response to falling commodity prices, Lightstream announced a reduction to our dividend of 62.5% from $0.04 per Common Share to $0.015 per Common Share commencing with the December 2014 dividend paid in January 2015.

Year Ended December 31, 2015

On January 19, 2015 we announced the suspension of our dividend program due to continued low WTI oil prices.

On May 29, 2015, we renegotiated the terms of our Credit Facility. The borrowing base amount under the amended Credit Facility was $750 million, subject to re-determination on a semi-annual basis, and a maturity date of June 2, 2017, subject to further extension. The agreement provides that during the term of the Credit Facility, the Company will not pay cash dividends without the unanimous consent of the lenders. The Credit Facility covenants were amended to a single covenant that limits the ratio of facility borrowing to trailing twelve-month adjusted earnings before interest, taxes, depreciation and amortization.

During the third quarter 2015, the Company issued a total of US$650 million of 9.875% Secured Notes due 2019. US$450 million of the Secured Notes were issued in exchange for US$546 million of outstanding Unsecured Notes, which were cancelled, and US$200 million of the Secured Notes were issued for cash proceeds which were used to reduce outstanding borrowing under our Credit Facility.

On November 13, 2015, as a result of the semi-annual borrowing base re-determination, the borrowing base under our Credit Facility was reduced to $550 million from $750 million.

Recent Developments

On February 8, 2016, the Convertible Notes matured and Lightstream repaid the remaining principal amount outstanding of US$4.5 million.

The next borrowing base re-determination under our Credit Facility is scheduled for April 30, 2016. Assuming current economic conditions persist, management anticipates the borrowing base could be further reduced at the next re-determination.

DESCRIPTION OF OUR BUSINESS

General

Lightstream is engaged in the exploration, development and production of oil and natural gas reserves in the provinces of Alberta, British Columbia and Saskatchewan with a focus on light oil. Our principal operating areas include southeast Saskatchewan in the Bakken and Mississippian formations, central Alberta in the Cardium formation and north-central Alberta in the Swan Hills area. Our properties and assets consist of proved producing (as defined herein) crude oil and natural gas reserves, proved plus probable (as defined herein) crude oil and natural gas reserves not yet on production and land.

We develop our properties through a detailed technical analysis of information including reservoir characteristics, oil in place, recovery factors and the application of enhanced recovery techniques and optimizations. Our focus has always been to increase the efficiency of our oil production in a cost effective manner through a number of techniques, including, but not limited to application of horizontal drilling and multi-stage fracturing completion techniques, enhanced oil recovery ("**EOR**") through the injection of natural gas and other fluids, optimization through millouts, cleanouts, high volume lift installations or casing gas compressor installations and slick-water fracturing. Technological advancements such as these allow us to increase our recovery factors while potentially lowering our decline rates and operating costs.

Strategy

Lightstream's long term strategy is to deliver accretive production and reserves growth and value for the benefit of shareholders. Under our business model, we strive to develop new resource plays that have large oil-in-place, apply our knowledge, experience and the latest technologies to grow production and use the excess cash generated to explore new opportunities and ultimately pay dividends to shareholders. As our production base matures, the base decline rate typically moderates allowing us to generate additional free operating cash flow.

We remain committed to preserving the long-term value of our assets through the continuing downturn of this commodity price cycle. As a result, we do not intend to deploy discretionary development capital on operated areas during the first half of 2016. Instead, our 2016 capital plan will focus on capital maintenance projects, optimization and EOR initiatives to moderate our declines. While we continue to restrict capital spending in this environment, we are prepared, assuming available liquidity at the time, to initiate a drilling program when the macro-economic environment warrants investment.

In 2014, we announced our initiative to sell all or part of the Bakken Business Unit in order to reduce debt and transform our balance sheet. We are continuing to pursue this initiative, as well as other asset sales and strategies in order to improve our long-term capital structure and liquidity.

Specialized Skill and Knowledge

The Company believes our success is dependent on the performance of our management and employees, many of whom have specialized knowledge and skills relating to oil and gas operations and public company management. We believe that we have adequate personnel with the specialized skills required to successfully carry out our operations.

Environmental, Safety and Social Responsibility

Lightstream is committed to managing and operating in a safe, efficient and environmentally responsible manner in association with our industry partners and is committed to improving our environment, health, safety and social performance. We have implemented environmental health and safety policies, procedures and programs to meet or exceed industry standards and legislative requirements.

We support and endorse the Environmental Operating Procedures developed by the Canadian Association of Petroleum Producers. Key environmental considerations include air quality and climate change, water conservation, spill management, waste management plans, lease and right-of-way management, natural and historic resources protection, and liability management (including site assessment and remediation). These practices and procedures apply to our employees and we monitor all activities and make reasonable efforts to ensure that companies who provide services to us will operate in a manner consistent with our environmental policy.

Our environmental management plan and operating guidelines focus on minimizing the environmental impact of our operations while meeting regulatory requirements and corporate standards. We maintain an active comprehensive integrity monitoring and management program for our surface piping, facilities, storage tanks and underground pipelines. Contingency plans are in place for timely response to an environmental event and abandonment, remediation and reclamation programs are in place and utilized to restore the environment. We also perform a detailed due diligence review as part of the acquisition process to determine whether the acquired assets are in regulatory and environmental compliance and assess any liabilities with respect thereto.

Lightstream expects to incur abandonment and site reclamation costs as existing oil and gas properties are abandoned and reclaimed. In 2015, expenditures for normal compliance with environmental regulations as well as expenditures beyond normal compliance were $2.1 million and the Company anticipates these expenditures to be approximately $1.7 million in 2016. See *"Additional Information Relating to Reserves Data – Additional Information Concerning Abandonment and Reclamation Costs"*.

Risk Management

Factors outside our control impact, to varying degrees, the prices we receive for production and the associated operating expenses we incur. These include but are not limited to:

(a) world market forces and political conditions that impact the global prices for crude oil, including the ability of OPEC to adjust production and influence oil prices and the risk of hostilities in the Middle East and other regions throughout the world;

(b) North American market forces, most notably shifts in the balance between supply and demand for crude oil and natural gas and the implications for the price of crude oil and natural gas;

(c) increases or decreases in crude oil quality differentials and their implications for prices received by us;

(d) the impact of changes in the exchange rate between Canadian and U.S. dollars on prices received by us for our crude oil and natural gas;

(e) availability, proximity and capacity of oil and gas gathering systems, pipeline and processing facilities;

(f) price and availability of alternative fuels; and

(g) the effect of energy conservation measures and government regulations.

Fluctuations in commodity prices, quality differentials and foreign exchange and interest rates, among other factors, are outside of our control and yet can have a significant impact on the level of cash we have available for capital investment and potential payment of dividends to shareholders. To mitigate a portion of these risks, we actively initiate, manage and disclose the effects of our hedging activities. Our strategy for crude oil and natural gas production is to hedge to a maximum of 50% of our existing production after royalties, on a rolling three year basis, at the discretion of management. All hedging activities are governed by our risk management policies and are regularly reviewed by the Board. We further mitigate our risk by transacting with a number of counterparties for the sale of our oil and natural gas, thereby limiting our exposure to any one counterparty.

Lightstream also, from time to time, enters into foreign exchange contracts to limit exposure to variability in exchange rates on US dollar interest payments on the Unsecured Notes and the Secured Notes, thereby providing increased stability of cash flows.

Employees

As at December 31, 2015, Lightstream had 349 full-time employees. Through a combination of normal attrition and workforce reductions that have been undertaken by Lightstream, the size of Lightstream's workforce has been reduced since December 31, 2015. As at March 29, 2016, Lightstream had 301 employees.

Principal Producing Properties

The following table summarizes our principal producing properties as of December 31, 2015 based on the Sproule Report using forecast prices and costs. The table also contains our average daily production of oil, natural gas and NGL for the year ended December 31, 2015.

Summary of Company Interest at December 31, 2015[(1)]
(Forecast Prices and Costs)[(2)]

Field	P+P Reserves Mboe[(3)]	P+P Value Before Tax at 10% DR [(4)]$MM	2015 Lt/Med Oil and NGL Production [(5)]bbl/d	2015 Gas Production MMcf/d	2015 Total Production BOE/d[(3)]
Bakken and Conventional (SE SK)	63,061	1,270	10,859	5,439	11,765
Cardium (Central AB)	66,251	780	9,816	40,517	16,569
Alberta/BC	13,109	134	1,995	6,378	3,058
Total	142,421	2,184	22,670	52,334	31,392

Notes:

1. The estimates of reserves and P+P value for individual properties may not reflect the same confidence level as estimates of reserves and P+P value for all properties, due to the effects of aggregation.
2. Forecast prices are shown under the heading *"Pricing Assumptions – Forecast Prices and Costs"*.
3. Natural gas has been converted to barrels of oil equivalent on the basis of six (6) Mcf of natural gas being equal to one barrel of oil.
4. Estimated P+P value disclosed do not represent fair market value.
5. NGLs and heavy oil have been included with light/medium oil, as they are not considered to be material.

Bakken Business Unit (Saskatchewan)

Lightstream's Saskatchewan assets produce light oil primarily from the Bakken and conventional Mississippian formations. Lightstream has over 284 gross (253 net) sections of undeveloped land in Saskatchewan and has identified more than 1,000 drilling locations. These are comprised of 805 locations from the unconventional asset and 209 locations from the conventional Mississippian asset. Of the 805 Bakken locations, 259 were assigned proved plus probable reserves by Sproule in the Sproule Report. The remaining 546 locations are largely commercial unbooked locations with possible and contingent reserves that are based on mapping, well controls, drilling results and stepping out past Sproule's bookings, and a number of sub-commercial unbooked locations with contingent resources, based on well control and mapping. Of the 209 Mississippian locations, 34 have been assigned proved plus probable reserves by Sproule in the Sproule Report. The remaining 175 locations are commercial unbooked locations with possible reserves based on uphole hydrocarbon shows from existing Bakken (or deeper) well control, mapping and seismic data.

These assets lie within mature oilfields with extensive infrastructure, and the majority of our Bakken business unit assets are tied into operated gathering systems and processing facilities with pipeline access. Production is relatively mature in the Bakken business unit, providing us with free cash flow in excess of capital investment.

In 2015, Lightstream drilled a total of 7.7 net wells in the southeast Saskatchewan area, of which 5.2 targeted the Bakken formation and 2.5 targeted the Mississippian formation. Average production for 2015 was 11,765 boepd. In first half 2016, Lightstream does not anticipate drilling any operated wells as we are restricting development capital through the continuing downturn of this commodity price cycle.

In southeast Saskatchewan, Lightstream uses natural gas injection for EOR. EOR is designed to attenuate declining production by increasing pressure through the injection of natural gas into the reservoir. We have a 13 section Creelman EOR unit with four gas injection wells, two of which were drilled in 2014 and began injecting gas in early 2015. We advanced the development of the Bakken gas flood program in 2015 through two well conversions to gas injectors, bringing total development to 7 wells on injection.

Cardium Business Unit (Alberta)

Lightstream's Cardium business unit assets primarily produce light oil from the Cardium formation. Lightstream holds a land position of approximately 433 gross (302 net) sections, of which approximately 253 net sections represent Cardium formation rights stretching from west of Calgary to west of Edmonton, Alberta. We have identified over 430 locations in the Cardium business unit comprised of 397 locations from the Cardium unconventional asset, and 35 locations from the Mannville Falher and Notikewan formations. Of the 397 Cardium locations, 150 were assigned proved plus probable reserves by Sproule in the Sproule Report. The remaining 247 locations are commercial unbooked locations with possible or contingent reserves that are based on mapping, well control, drilling results and stepping out past Sproule's bookings. Of the 35 locations from the Mannville formations, one was assigned proved plus probable reserves by Sproule in the Sproule Report, and the other 34 locations are commercial unbooked locations with possible reserves based on well control, seismic data, drilling results and mapping.

Average production in our Cardium business unit was 16,569 boepd in 2015.

In 2015, we drilled 10.3 net wells in the Cardium business unit and do not anticipate drilling any operated wells in the first half of 2016. Early in 2016, we put one net Falher gas well on-stream in the Brazeau area and will continue to monitor the current price environment for further drilling opportunities. We have continued to optimize our drilling and completion techniques in the Cardium and have made key investments to de-bottleneck infrastructure and reduce operating expenses. We expect the Cardium to continue to represent a future growth area for the Company.

Alberta/BC Business Unit

Lightstream has established a material land position in Alberta with over 599 gross (509 net) undeveloped sections in emerging oil and liquid-rich gas focused resource plays, which we believe provide opportunities for future production growth. In recent years, we have focused the majority of our investment for this business unit on developing the Swan Hills formation of the Deer Mountain region, which is a light oil resource style play.

We have identified 120 locations in the Alberta/BC business unit comprised of 78 locations from the Swan Hills unconventional asset and the remaining locations in other areas of the business unit. Of the 78 Swan Hills locations 39 were assigned proved plus probable reserves by Sproule in the Sproule Report and the remaining locations are unbooked commercial locations with possible reserves plus some locations with contingent resources that are based on mapping, well control, drilling results and stepping out past Sproule's bookings. We have an additional 2 booked locations in the upper Cretaceous and Mannville formations in southern Alberta and the remaining 40 locations are commercial unbooked locations with possible and contingent reserves based on well control, seismic data, drilling results and mapping.

Aside from the Swan Hills area, this asset requires higher sustained gas prices for development, and we currently do not plan to invest capital in this asset in first half 2016 due to the current economic environment.

We drilled no new wells in the Swan Hills area in 2015. Average production in our Alberta/BC business unit was 3,058 boepd in 2015 with over half of the production (2,014 boepd) coming from our Swan Hills development.

STATEMENT OF RESERVES DATA

Notes on Reserves Data

Crude oil, natural gas liquids and natural gas reserves estimates presented in the Sproule Report are based on the definitions and guidelines contained in the COGE Handbook. A summary of those definitions is set forth below:

Reserve Categories

Reserves are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, as of a given date forward, based on:

- analysis of drilling, geological, geophysical and engineering data;
- the use of established technology; and
- specified economic conditions which are generally accepted as being reasonable, and shall be disclosed.

Reserves are classified according to the degree of certainty associated with the estimates.

Proved reserves are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.

Probable reserves are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves.

Other criteria that must also be met for the categorization of reserves are provided in the COGE Handbook.

Each of the reserve categories (proved and probable) may be divided into developed and undeveloped categories.

Developed reserves are those reserves that are expected to be recovered from existing wells and installed facilities or, if facilities have not been installed, that would involve a low expenditure (for example, when compared to the cost of drilling a well) to put the reserves on production. The developed category may be subdivided into producing and non-producing.

Developed producing reserves are those reserves that are expected to be recovered from completion intervals open at the time of the estimate. These reserves may be currently producing or, if shut-in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainty.

Developed non-producing reserves are those reserves that either have not been on production, or have previously been on production, but are shut-in, and the date of resumption of production is unknown.

Undeveloped reserves are those reserves expected to be recovered from known accumulations where a significant expenditure (for example, when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves category (proved or probable) to which they are assigned.

In multi-well pools it may be appropriate to allocate total pool reserves between the developed and undeveloped categories or to subdivide the developed reserves for the pool between developed producing and developed non-producing. This allocation should be based on the estimator's assessment as to the reserves that will be recovered from specific wells, facilities and completion intervals in the pool and their respective development and production status.

Levels of Certainty for Reported Reserves

The qualitative certainty levels referred to in the definitions above are applicable to individual reserve entities (which refers to the lowest level at which reserves calculations are performed) and to reported reserves (which refers to the highest level sum of individual entity estimates for which reserves are presented). Reported reserves should target the following levels of certainty under a specific set of economic conditions:

- at least a 90 percent probability that the quantities actually recovered will equal or exceed the estimated proved reserves; and
- at least a 50 percent probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable reserves.

A qualitative measure of the certainty levels pertaining to estimates prepared for the various reserves categories is desirable to provide a clearer understanding of the associated risks and uncertainties. However, the majority of reserves estimates will be prepared using deterministic methods that do not provide a mathematically derived quantitative measure of probability. In principle, there should be no difference between estimates prepared using probabilistic or deterministic methods.

Additional clarification of certainty levels associated with reserve estimates and the effect of aggregation is provided in the COGE Handbook.

The estimates of reserves and future net revenue for individual properties may not reflect the same confidence level as estimates of reserves and future net revenue for all properties, due to the effects of aggregation.

Estimated future well abandonment and disconnect have been included in the Sproule Report calculation of net reserves for all wells that are assigned reserves.

Columns contained in this Annual Information Form may not add due to rounding.

<u>Disclosure of Reserves Data</u>

The reserves data set forth herein is based upon evaluations completed by Sproule. The reserves data contained herein summarizes the oil, NGLs, and natural gas reserves of the Company and the net present values of future net revenue for these reserves using forecast prices and costs. The reserves data complies with the requirements of NI 51-101. Lightstream engaged Sproule to provide evaluations of proved and probable reserves. Certain additional information not required by NI 51-101 has been included herein to provide readers with further information regarding our properties.

All of the Company's reserves are in Canada (specifically, in the provinces of Saskatchewan, Alberta and British Columbia).

In preparing the Sproule Report, basic information was provided to Sproule by Lightstream, which included land data, well information, geological information, reservoir studies, estimates of on-stream dates, contract information, current hydrocarbon product prices, operating cost data, capital budget forecasts, financial data and future operating plans. Other engineering, geological or economic data required to conduct the evaluations and upon which the Sproule Report is based, was obtained from public records, other operators and from Sproule's non-confidential files. The extent and character of ownership and the accuracy of all factual data supplied for the Sproule Report, from all sources, was accepted by Sproule as represented.

The tables and information contained herein show the estimated share of Lightstream's crude oil, natural gas and NGL reserves in our Canadian properties and the present value of estimated future net revenue for these reserves, after provision for Alberta gas cost allowance, using forecast prices and costs as indicated.

All evaluations and reviews of future net cash flow are stated prior to any provision for interest costs or general and administrative costs and after the deduction of estimated future capital expenditures for wells to which reserves have been assigned and estimated future well abandonment costs. It should not be assumed that the estimated future net cash flow shown below is representative of the fair market value of the Company's properties. There is no assurance that such price and cost assumptions will be attained and variances could be material. The recovery and reserve estimates of crude oil, NGL and natural gas reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual crude oil, NGL and natural gas reserves may be greater than or less than the estimates provided herein.

The reserves data contained herein is based on Sproule's price forecasts, as of December 31, 2015. Reserves information has been provided on a gross and net basis in accordance with NI 51-101. The Company has also previously publicly disclosed our reserves on a "company interest" basis (being the gross volumes plus the Company's share of royalty interests in reserves), which results in an additional 262 Mboe of proved plus probable reserves attributable to the Company. "Company interest" is not a term defined by NI 51-101 and may not be comparable to reserves estimates disclosed by others in accordance with NI 51-101.

Summary of Oil and Gas Reserves – Forecast Prices and Costs

	Company Gross Reserves				
	Light and Medium Oil	Heavy Oil	Natural Gas	Natural Gas Liquids	Total
	Mbbls	Mbbls	MMcf	Mbbls	Mboe
Proved					
Developed Producing	35,628	96	89,298	5,360	55,967
Developed Non-Producing	1,489	0	4,166	228	2,411
Undeveloped	22,275	115	36,770	2,550	31,069
Total Proved	59,392	211	130,234	8,138	89,447
Probable	37,596	41	63,338	4,519	52,712
Total Proved plus Probable	96,988	252	193,572	12,657	142,159

Company Net Reserves	Light and Medium Oil Mbbls	Heavy Oil Mbbls	Natural Gas MMcf	Natural Gas Liquids Mbbls	Total Mboe
Proved					
Developed Producing	32,084	79	77,080	4,166	49,176
Developed Non-Producing	1,341	0	3,676	187	2,141
Undeveloped	20,308	76	33,341	2,163	28,104
Total Proved	53,733	155	114,097	6,516	79,421
Probable	33,574	29	56,263	3,722	46,702
Total Proved plus Probable	87,307	184	170,360	10,238	126,123

Net Present Value of Future Net Revenue – Forecast Prices and Costs

	Before Future Income Tax Expenses and Discounted at				
	0% (M$)	5% (M$)	10% (M$)	15% (M$)	20% (M$)
Proved					
Developed Producing	1,556,640	1,256,888	1,041,846	885,994	769,950
Developed Non-Producing	57,396	46,939	38,892	32,752	28,012
Undeveloped	741,676	470,812	304,135	197,549	126,727
Total Proved	2,355,712	1,774,639	1,384,872	1,116,295	924,690
Probable	1,837,557	1,171,719	798,889	574,624	430,426
Total Proved plus Probable	4,193,268	2,946,358	2,183,761	1,690,919	1,355,115

	After Future Income Tax Expenses and Discounted at				
	0% (M$)	5% (M$)	10% (M$)	15% (M$)	20% (M$)
Proved					
Developed Producing	1,535,356	1,245,997	1,036,071	882,832	768,168
Developed Non-Producing	41,076	37,447	33,226	29,289	25,850
Undeveloped	536,298	338,046	214,571	135,032	81,856
Total Proved	2,112,729	1,621,490	1,283,868	1,047,153	875,874
Probable	1,332,138	846,126	572,778	408,870	304,042
Total Proved plus Probable	3,444,867	2,467,616	1,856,646	1,456,024	1,179,916

	Unit Value Before Income Tax Discounted at 10%/year ($/BOE)
Proved	
Developed Producing	21.19
Developed Non-Producing	18.17
Undeveloped	10.82
Total Proved	17.44
Probable	17.11
Total Proved Plus Probable	17.31

Additional Information Concerning Future Net Revenue – Forecast Prices and Costs (Undiscounted)

(Undiscounted)	Revenue (M$)	Royalties (M$)	Operating Costs (M$)	Development Costs (M$)	Well Abandonment/Other Costs (M$)	Future Net Revenue Before Income Taxes (M$)	Income Taxes (M$)	Future Net Revenue After Income Taxes (M$)
Total Proved	6,010,093	657,592	2,165,209	677,005	154,575	2,355,712	242,983	2,112,729
Total Proved plus Probable	10,141,113	1,148,505	3,475,798	1,128,811	194,731	4,193,268	748,402	3,444,867

Future Net Revenue by Product Type – Forecast Prices and Costs

	Future Net Revenue Before Income Taxes and Discounted at 10% (M$)	Per Unit Future Net Revenue Before Income Taxes and Discounted at 10% ($/BOE)
Proved Reserves		
Light and Medium Crude Oil[1]	1,345,137	17.91
Heavy Oil[1]	1,936	11.77
Natural Gas[2]	32,623	7.87
Other Income[3]	5,176	-
Proved plus Probable Reserves		
Light and Medium Crude Oil[1]	2,133,707	17.77
Heavy Oil[1]	2,377	12.14
Natural Gas[2]	41,936	7.17
Other Income[3]	5,741	-

Notes:

1. Including solution gas and other by-products.
2. Including by-products, but excluding solution gas from oil wells.
3. Includes Alberta gas cost allowance, select scheduled abandonment and reclamation costs, processing income and other minor items.

Pricing Assumptions – Forecast Prices and Costs

Sproule employed the following pricing and exchange rate assumptions as of December 31, 2015 in the Sproule Report in estimating reserves data using forecast prices and costs. Operating costs were inflated at 0% from 2016 to 2017, then 1.5% per year thereafter. Capital costs were inflated at 0% for 2016, 4% for 2017 to 2019, then 1.5% thereafter. The weighted average historical prices for 2015 are also reflected in the table below.

Year	WTI Cushing Oklahoma ($US/bbl)	Canadian Light Sweet Crude 40° API ($Cdn/bbl)	Cromer LSB 35º API ($Cdn/bbl)	Natural Gas[1] AECO Gas Price ($/MMBtu)	Pentanes Plus FOB Field Gate ($Cdn/bbl)	Butanes FOB Field Gate ($Cdn/bbl)	Exchange Rate[2] ($US/ $Cdn)
2015 (Actual)	$48.80	$57.45	$56.51	$2.70	$61.45	$36.81	0.783
2016	$45.00	$55.20	$54.20	$2.25	$59.10	$39.09	0.750
2017	$60.00	$69.00	$68.00	$2.95	$73.88	$51.43	0.800
2018	$70.00	$78.43	$77.43	$3.42	$83.98	$58.46	0.830
2019	$80.00	$89.41	$88.41	$3.91	$95.73	$66.64	0.850
2020	$81.20	$91.71	$90.71	$4.20	$98.19	$68.35	0.850

Notes:

1. This summary table identifies benchmark reference pricing schedules that might apply to a reporting issuer.
2. Exchange rates used to generate the benchmark reference prices in this table.

Reconciliation of Gross Reserves

The following table sets forth a reconciliation of Lightstream's gross reserves as at December 31, 2015, derived from the Sproule Report using forecast prices and cost estimates.

	Light and Medium Oil	Heavy Oil	Coalbed Methane	Natural Gas	Natural Gas Liquids
Proved	(Mbbl)	(Mbbl)	(MMcf)	(MMcf)	(Mbbl)
Balance at December 31, 2014	70,435	13	60	141,988	8,788
Extensions and Improved Recovery	87	0	0	1,080	40
Infill Drilling	586	0	0	3,919	199
Technical Revisions	-1,780	231	-35	14,474	678
Discoveries	0	0	0	0	0
Acquisitions	9	0	0	7	3
Dispositions	0	0	0	-285	-2
Economic Factors	-2,744	-15	-18	-11,853	-514
Production	-7,201	-18	-7	-19,096	-1,054
Balance at December 31, 2015	59,392	211	0	130,234	8,138

Probable	Light and Medium Oil (Mbbl)	Heavy Oil (Mbbl)	Coalbed Methane (MMcf)	Natural Gas (MMcf)	Natural Gas Liquids (Mbbl)
Balance at December 31, 2014	42,492	9	593	65,680	4,286
Extensions and Improved Recovery	256	0	0	426	27
Infill Drilling	1,593	0	0	1,937	252
Technical Revisions	-6,537	41	-586	-6,073	-145
Discoveries	0	0	0	0	0
Acquisitions	4	0	0	3	1
Dispositions	0	0	0	-128	-1
Economic Factors	-212	-9	-7	1,493	100
Production	0	0	0	0	0
Balance at December 31, 2015	37,596	41	0	63,338	4,519

Proved + Probable	Light and Medium Oil (Mbbl)	Heavy Oil (Mbbl)	Coalbed Methane (MMcf)	Natural Gas (MMcf)	Natural Gas Liquids (Mbbl)
Balance at December 31, 2014	112,927	22	653	207,668	13,073
Extensions and Improved Recovery	343	0	0	1,506	67
Infill Drilling	2,180	0	0	5,856	452
Technical Revisions	-8,318	272	-621	8,402	533
Discoveries	0	0	0	0	0
Acquisitions	13	0	0	9	4
Dispositions	0	0	0	-413	-4
Economic Factors	-2,956	-24	-25	-10,360	-414
Production	-7,201	-18	-7	-19,096	-1,054
Balance at December 31, 2015	96,988	252	0	193,572	12,657

ADDITIONAL INFORMATION RELATING TO RESERVES DATA

Undeveloped Reserves

The following table sets forth the volumes of proved undeveloped reserves that were first attributed in each of the three most recent financial years:

	Light and Medium Crude Oil (Mbbl)	Natural Gas (MMcf)	Natural Gas Liquids (Mbbl)
2013	5,077	8,300	435
2014	4,941	7,340	662
2015	536	1,241	102

The following table sets forth the volumes of probable undeveloped reserves that were first attributed in each of the three most recent financial years:

	Light and Medium Crude Oil	Natural Gas	Natural Gas Liquids
	(Mbbl)	(MMcf)	(Mbbl)
2013	5,778	6,295	421
2014	4,821	5,847	555
2015	1,845	1,507	248

Lightstream attributes proved and probable undeveloped reserves based on accepted engineering and geological practices as defined under NI 51-101. These practices include the determination of reserves based on the presence of commercial test rates from either production tests or drill stem tests, extensions of known accumulations based upon both geological and geophysical information, and the optimization of existing fields.

Subject to the success of operations, within the next two years, Lightstream has the following plans regarding the development of proved and probable undeveloped reserves:

1. Proved undeveloped locations were assigned on the basis of the regional nature of the producing formations. Performance expectations are based on offset well production. Locations typically were assigned where economic production has been demonstrated by wells in offsetting spacing units. The Sproule Report has assigned proved undeveloped reserves to 168 net light oil locations in the Bakken business unit, 90 net light oil and natural gas locations in the Cardium business unit and 26 net light oil locations in the Alberta/BC business unit. For Lightstream's total proved undeveloped program, approximately 4% of the capital is forecast to be spent in 2016 and approximately 40% of the forecasted capital scheduled to be spent by the end of 2017.

2. Probable undeveloped locations are generally assigned adjacent to proved locations. The Sproule Report has assigned probable undeveloped reserves to 125 net light oil locations in the Bakken business unit, 61 net light oil locations in the Cardium business unit and 15 net light oil locations in the Alberta/BC business unit. For Lightstream's total probable undeveloped program, approximately 7% of the capital is forecast to be spent in 2016 and over approximately 28% of the forecasted capital is scheduled to be spent by the end of 2017.

Lightstream's current 2016 drilling plan is dependent on a number of factors including commodity prices, capital costs, well results, economic conditions, availability of equipment and personnel, weather and access to drilling locations. For the first half of 2016, we do not plan to drill any operated wells due to commodity prices and current well costs. We are prepared to initiate an operated drilling program should these factors improve. Once we initiate an operated drilling program, wells are primarily expected to be drilled in central Alberta on our Cardium property and in southeast Saskatchewan, on both the Bakken and conventional Mississippian properties. See "*Risk Factors*" for a complete list of factors that may impact our drilling plan.

Undeveloped reserves, like all projects, are subject to competition for capital and consequently may be delayed or accelerated from time to time.

Future Development Costs

The table below sets out the total development costs deducted in the estimation in the Sproule Report of future net revenue attributable to proved reserves and proved plus probable reserves (using forecast prices and costs).

Year	Total Proved Reserves	Total Proved Plus Probable Reserves
	(CDN M$)	(CDN M$)
2016	27,998	61,649
2017	246,324	372,993
2018	192,851	277,903
2019	151,870	222,780
Thereafter	57,962	193,485
Total undiscounted	677,005	1,128,810
Total discounted at 10%	538,846	887,266

Future development costs are expected to be funded by internally generated cash flow, and if necessary from a combination of potential debt and/or equity financings, the costs of which are not expected to have an effect on the reserves or future net revenue.

2016 Production Estimates

The following table sets out the volume of the Company's production estimated by Sproule for the year ended December 31, 2016 which is reflected in the estimate of future net revenue disclosed in the tables contained in this Annual Information Form.

	Light and Medium Oil	Heavy Oil	Natural Gas[1]	Natural Gas Liquids	Oil Equivalent
Reserves Category	Gross (bbl/d)	Gross (bbl/d)	Gross (Mcf/d)	Gross (bbl/d)	Gross (boe/d)
Total Proved Producing	15,036	44	37,956	2,335	23,741
Total Proved	15,723	44	40,301	2,459	24,943
Total Proved Plus Probable	17,432	45	43,429	2,693	27,408

Note:

1. Natural Gas includes all solution gas, plus associated and non-associated gas. Natural gas is separate from Coalbed Methane and Shale Gas.

Significant Factors or Uncertainties Affecting Reserves Data

There are numerous uncertainties inherent in estimating quantities of proved reserves, including many factors beyond the control of the Company. The reserve data included herein represents estimates only. In general, estimates of economically recoverable oil and natural gas reserves and the future net cash flows therefrom are based upon a number of variable factors and assumptions, such as historical production from the properties, the assumed effects of regulation by governmental agencies and future operating costs, all of which may vary considerably from actual results. All such estimates are to some degree speculative, and classifications of reserves are only attempts to define the degree of speculation involved. For those reasons, estimates of the economically recoverable oil and natural gas reserves attributable to any particular group of properties, classification of such reserves based on risk of recovery and estimates of future net revenues expected therefrom, prepared by different engineers or by the same engineers at different times, may vary substantially. The actual production, revenues, taxes and development and operating expenditures of the Company with respect to these reserves will vary from such estimates, and such variances could be material.

Estimates with respect to proved reserves that may be developed and produced in the future are often based upon volumetric calculations and upon analogy to similar types of reserves rather than actual production history.

Estimates based on these methods are generally less reliable than those based on actual production history. Subsequent evaluation of the same reserves based upon production history will result in variations, which may be substantial, in the estimated reserves.

Consistent with the securities disclosure legislation and policies of Canada, the Company has used forecast prices and costs in calculating reserve quantities included herein. Actual future net cash flows also will be affected by other factors such as actual production levels, supply and demand for oil and natural gas, curtailments or increases in consumption by oil and natural gas purchasers, changes in governmental regulation or taxation and the impact of inflation on costs.

Oil and Gas Wells

The following table summarizes Lightstream's interests, by region and on a consolidated basis, as at December 31, 2015, in oil and natural gas wells which are producing or which are considered capable of production and in non-producing wells.

	Producing				Non-Producing			
	Oil		Natural Gas		Oil		Natural Gas	
Area	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Saskatchewan	1,015	770	0	0	245	135	4	1
Alberta	569	458	325	205	178	126	193	129
British Columbia	0	0	22	17	0	0	31	16
Total Lightstream	1,584	1,228	347	222	423	261	228	146

Land Holdings – Consolidated

The land holdings of the Company, including those that are undeveloped, by region and on a consolidated basis, as at December 31, 2015, are set forth in the following table (in 000s of acres unless otherwise noted).

	Developed		Undeveloped[1]		Total		Avg.
Area	Gross	Net	Gross	Net	Gross	Net	WI%
Saskatchewan	185	141	182	162	367	303	83%
Alberta	343	248	383	326	727	574	79%
British Columbia	35	26	38	30	73	57	78%
Northwest Territories	0	0	6	2	6	2	34%
Total Lightstream	563	415	609	520	1,173	936	80%

Note:

1. Provincial governments (for Crown mineral lands) and private mineral owners (for freehold mineral lands) in Canada grant rights to explore for and produce oil and natural gas under leases, licenses and permits, which may be continued indefinitely by producing under these lease agreements. Accordingly, to preserve this acreage the Company is committed to bring wells on production.

The Company expects that rights to explore, develop and exploit 203,024 net acres of our undeveloped land in Canada are scheduled to expire by December 31, 2016. The Company will attempt to extend some of this expiring acreage through any continuation provisions we are afforded under the individual title documents and applicable governmental regulations.

Forward Contracts and Future Commitments

See Note 16, *"Financial Instruments and Financial Risk Management"*, and Note 18, *"Commitments and Contingencies"*, to the Company's December 31, 2015 consolidated financial statements, which information is incorporated herein by reference, and was filed on SEDAR on March 3, 2016 under the Company's profile at www.sedar.com.

Additional Information Concerning Abandonment and Reclamation Costs

Abandonment and reclamation costs were estimated for all legal obligations associated with the retirement of long-lived tangible assets such as wells, facilities and plants based on market prices or on the best information available where no market price was available. For obligations in Canada, the estimated costs are then inflated at two percent over time until the actual retirement is expected to occur.

As at December 31, 2015, Lightstream expected to incur future abandonment and reclamation costs in respect to all of our net wells.

The total abandonment and reclamation costs, net of salvage values of all Lightstream's operations, on a consolidated basis, are estimated to be $194.9 million on an undiscounted basis and $41.4 million discounted at 10 percent. In the next three financial years, Lightstream anticipates that approximately $9.8 million on an undiscounted basis and $8.3 million discounted at 10 percent will be incurred on abandonment and reclamation costs.

The future net revenue disclosed in the Sproule Report in this Annual Information Form does not contain an allowance for abandonment and reclamation costs for suspended wells, facilities and pipelines. The Sproule Report deducted $194.7 million (undiscounted) and $26.3 million (discounted at 10 percent) for downhole abandonment and disconnect costs for wells to which reserves were assigned, on a total proved plus probable basis. In the next three financial years, the Sproule Report estimates an abandonment and reclamation cost of $1.6 million on an undiscounted basis and $1.5 million discounted at 10 percent.

Tax Horizon

Lightstream has a Canadian tax pool balance of approximately $1.5 billion as at December 31, 2015, which can be used to shelter future taxable income. Based on the Sproule Report, Lightstream's exploration and development plans, and forecasted commodity pricing, Lightstream does not expect to pay income tax in Canada for at least the next five years. The following table summarizes the Company's Canadian tax pools as at December 31, 2015.

(000s)	Total
Canadian development expenses (CDE)	$ 819,534
Undepreciated capital costs (UCC)	357,469
Non-capital losses and Canadian exploration expenses (CEE)	341,557
Share issuance and financing costs	12,736
Total tax pools	$ 1,531,296

Capital Expenditures

The following table summarizes capital expenditures related to the Company's activities for the year ended December 31, 2015.

($000s)	Total
Drilling, completions, equipping and recompletions	78,038
Facilities	17,989
Land	2,092
Seismic	(780)
Other [(1)]	9,232
Capital expenditures before acquisitions	106,571
Asset acquisitions	617
Asset dispositions	(12,143)
Total net capital expenditures	95,045

Note:

1. Includes health, safety and environmental, direct salaries and office furniture and fixtures.

Costs Incurred

The following table summarizes the property acquisition, exploration and development costs incurred for the year ended December 31, 2015.

	Acquisition Costs [(1)]			
	Proved	Unproved [(2)]	Exploration	Development
Total ($000s)	359	385	1,561	104,882

Notes:

1. Pursuant to NI 51-101, "proved properties" are all properties to which proved reserves have been specifically attributed and "unproved properties" are properties to which no reserves have been specifically attributed.
2. Includes $0.1 million of land acquisition costs incurred by Lightstream in 2015, and $0.3 million of asset acquisition costs.

Exploration and Development

The following table summarizes the gross and net exploratory and development wells in which the Company participated during the year ended December 31, 2015.

	Exploration		Development		Total	
	Gross	Net	Gross	Net	Gross	Net
Oil	-	-	22	14	22	14
Natural Gas	-	-	6	4	6	4
Dry	-	-	-	-	-	-
Service Wells	-	-	1	1	1	1
Total	-	-	29	19	29	19
Success Rate	-	-	100%	100%	100%	100%

Lightstream's exploration and development plans are discussed under the heading *"Description of Our Business"*.

Production History

Production

The following tables disclose, on a quarterly and annual basis for the year ended December 31, 2015, our share of average daily production volumes (prior to deducting royalties), and the prices received, royalties paid, operating costs and netbacks on a per unit of volume basis for each product type.

	Three Months Ended				Year Ended
	Mar 31, 2015	June 30, 2015	Sept 30, 2015	Dec 31, 2015	Dec 31, 2015
Average daily production (1) (2)					
Light / medium oil and NGLs (bbl/d)	26,607	23,066	21,436	19,662	22,670
Natural gas (Mcf/d)	51,429	53,399	52,912	51,588	52,334
Total Lightstream (boe/d)	35,179	31,966	30,255	28,260	31,392

Notes:

1. NGLs have been included with light/medium oil as they are not considered material. NGLs represent approximately eight percent of Lightstream's total production.
2. Heavy oil has been included in light/medium oil as it is not considered material. Heavy oil represents less than one percent of Lightstream's total production.

Operating Netback by Product

Light/Medium Crude Oil and NGL Prices Received, Royalties, Operating Costs and Operating Netback[4] ($ per bbl)

	Three Months Ended				Year Ended
	Mar 31, 2015	June 30, 2015	Sept 30, 2015	Dec 31, 2015	Dec 31, 2015
Average price received (1)	44.79	58.29	47.45	45.39	48.98
Royalties	5.56	5.65	4.92	5.97	5.52
Operating costs (2)	14.19	14.82	14.62	14.64	14.55
Operating netback (3)	25.04	37.82	27.91	24.78	28.91

Notes:

1. Net of transportation expenses.
2. Operating costs are expenses incurred in the operation of producing properties and include items such as field staff salaries, power, fuel, chemicals, repairs and maintenance, property taxes, processing and treating fees, overhead fees and other costs.
3. Excludes hedging activities.
4. Heavy oil has been included in light/medium oil as it is not considered to be material. Heavy oil represents less than one percent of Lightstream's total production.

Natural Gas Prices Received, Royalties, Operating Costs and Operating Netback ($ per Mcf)

	Three Months Ended				Year Ended
	Mar 31, 2015	June 30, 2015	Sept 30, 2015	Dec 31, 2015	Dec 31, 2015
Average price received (1)	2.80	2.68	2.96	2.45	2.72
Royalties	0.27	0.23	0.39	0.32	0.30
Operating costs (2)	1.20	1.32	1.21	1.27	1.25
Operating netback (3)	1.33	1.13	1.36	0.86	1.17

Notes:

1. Net of transportation expenses.
2. Operating costs are expenses incurred in the operation of producing properties and include items such as field staff salaries, power, fuel, chemicals, repairs and maintenance, property taxes, processing and treating fees, overhead fees and other costs.
3. Excludes hedging activities.

The following table sets forth the Company's average daily production volumes, for each significant field and on a consolidated basis, for the twelve month period ended December 31, 2015.

	Lt/Med Oil and NGL (bbl)[1]	Gas (Mcf)	Total (boe)
Bakken	10,859	5,439	11,765
Cardium (Central AB)	9,816	40,517	16,569
Alberta/BC	1,995	6,378	3,058
Total Lightstream	22,670	52,334	31,392

Note:

1. NGLs and heavy oil have been included with light/medium oil, as they are not considered to be material.

CAPITAL STRUCTURE

Common Shares and Preferred Shares

The authorized capital of Lightstream consists of an unlimited number of Common Shares without nominal or par value and an unlimited number of preferred shares. As at December 31, 2015, there were 198,321,938 Common Shares and no preferred shares issued and outstanding. As at March 29, 2016, there were 198,499,007 Common Shares and no preferred shares issued and outstanding.

Holders of Common Shares are entitled to one vote per Common Share at meetings of holders of Common Shares, to receive dividends if, as and when declared by the Board with respect to the Common Shares and to receive pro rata the remaining property and assets of Lightstream upon our liquidation, dissolution or winding up, subject to the rights of shares having priority over the Common Shares.

The articles of the Company contain provisions facilitating payment of dividends on Common Shares through issuance of Common Shares in circumstances where a shareholder of the Company validly elects to receive payment of dividends, in whole or in part, in the form of Common Shares. The Company does not currently have a share dividend plan or a dividend reinvestment plan in place.

Preferred shares may at any time and from time to time be issued in one or more series. The Board may from time to time before the issue thereof fix the number of shares in, and determine the designation, rights, privileges, restrictions and conditions attaching to the shares of, each series of preferred shares. The preferred shares shall be entitled to priority over the Common Shares and all other shares ranking junior to the preferred shares with respect to the payment of dividends and the distribution of assets of Lightstream in the event of any liquidation, dissolution or winding up of Lightstream or other distribution of assets of Lightstream among our shareholders for the purpose of winding up our affairs. The preferred shares of each series shall rank on a parity with the preferred shares of every other series with respect to priority in the payment of dividends and in the distribution of assets of Lightstream in the event of any liquidation, dissolution or winding up of Lightstream or other distribution of assets of Lightstream among our shareholders for the purpose of winding up our affairs.

Shareholder Rights Plan

Effective January 1, 2013, Lightstream adopted the Shareholder Rights Plan, which was subsequently reconfirmed by the shareholders of the Company, including the Company's Independent Shareholders (as defined in the Shareholder Rights Plan), at the Company's 2015 annual general meeting. The Shareholder Rights Plan must next be renewed and approved by the Company's Independent Shareholders at the annual meeting to be held in 2018, failing which it will expire at such time. The Shareholder Rights Plan, under which Computershare acts as rights agent, generally provides that, following the acquisition by any person or entity of 20% or more of the issued and outstanding Common Shares (except pursuant to certain permitted or excepted transactions) and upon the occurrence of certain other events, each holder of Common Shares, other than such acquiring person or entity, shall be entitled to acquire Common Shares at a discounted price. The Shareholder Rights Plan is similar to other shareholder rights plans adopted by companies in the energy industry. A copy of the Shareholder Rights Plan was filed on March 31, 2015 as a "Security Holder Document" on the Company's SEDAR profile at www.sedar.com.

Secured Notes

At December 31, 2015, Lightstream had Secured Notes outstanding having an aggregate principal amount of US$650 million. The Secured Notes have a 9.875% coupon rate, paid semi-annually, and mature in June 2019. The Secured Notes are issued pursuant to the Secured Note Indenture, which contains restrictive covenants regarding distributions, dividends, share repurchases, asset sales and incurrence of debt, as well as customary provisions with respect to change-of-control, redemption and events of default. The Secured Note Indenture was filed on July 2, 2015 as a "Security Holders Document" on our SEDAR profile at www.sedar.com.

Unsecured Notes

At December 31, 2015, Lightstream had Unsecured Notes outstanding having an aggregate principal amount of US$254 million. The Unsecured Notes have an 8.625% coupon rate, paid semi-annually, and mature in February 2020. The Unsecured Notes are issued pursuant to the Unsecured Note Indenture, which contains restrictive covenants regarding distributions, dividends, share repurchases, asset sales and incurrence of debt, as well as customary provisions with respect to change of control, redemption and events of default. The Unsecured Note Indenture was filed on February 3, 2012 as a "Security Holders Document" on our SEDAR profile at www.sedar.com.

Convertible Notes

At December 31, 2015, Lightstream had US$4.5 million Convertible Notes outstanding which matured and were redeemed for cash on February 8, 2016.

CREDIT RATINGS

The following table outlines the current ratings of the Company and our Unsecured Notes.

	Standard & Poor's Ratings Services ("S&P")	Moody's Investors Service ("Moody's")
Company Rating	B-	Caa2
Outlook	Negative	Negative
Unsecured Notes Rating	CCC	Ca

In July 2015, Moody's affirmed its long-term corporate credit rating at Caa2 with a negative outlook, and its issue-level rating on our Unsecured Notes at Ca. In October 2015, S&P affirmed its long-term corporate credit rating at B- with a negative outlook, and its issue-level rating on our Unsecured Notes at CCC.

A credit rating generally provides an indication of the risk that the borrower will not fulfill its full obligations in a timely manner with respect to both interest and principal commitments.

S&P's credit ratings are on a rating scale that ranges from AAA to D, which represents the range from highest to lowest quality of such securities rated. S&P has assigned Lightstream a corporate credit rating of B-, negative outlook, and a credit rating of CCC on the Unsecured Notes. According to S&P's rating system, a credit rating of B- by S&P is within the sixth highest of ten categories and indicates more vulnerability to non-payment than obligations rated 'BB', but with current capacity to meet financial commitments; adverse business financial or economic conditions would likely impair capacity or willingness to meet financial commitments. S&P's credit rating of CCC indicates vulnerability to non-payment and dependence upon favourable business, financial and economic conditions for the obligor to meet its financial commitments; in the event of adverse conditions, the obligor is not likely to have the capacity to meet its financial commitments. The ratings from AA to CCC may be modified by the addition of a plus (+) or a minus (-) sign to show relative standing within the major rating categories. In addition, S&P may add a rating outlook of "positive", "negative" or "stable" which is an opinion regarding the potential direction of a long-term credit rating over the intermediate term (typically six months to two years).

Moody's credit ratings are on a rating scale that ranges from Aaa to C, which represents the range from highest to lowest quality of such securities rated. Moody's has assigned Lightstream a corporate family credit rating of Caa2, negative outlook, and a credit rating of Ca on the Unsecured Notes. According to Moody's rating system, securities rated 'Caa2' are within the seventh of nine categories and are judged to be speculative of poor standing and are subject to very high credit risk and securities rated 'Ca' are within the eighth of nine categories and are highly speculative and are likely in, or very near default, with some prospect of recovery of principal and interest. Moody's appends numerical modifiers 1, 2 and 3 to each generic rating classification from Aa through Caa. The modifier 1 indicates that the security ranks in the higher end of its generic rating category, the modifier 2 indicates a mid-range ranking and the modifier 3 indicates a ranking in the lower end of its generic rating category. In addition, Moody's may add a rating outlook of "positive", "negative" or "stable", which is an opinion regarding the likely direction of an issuer's rating over the medium term.

The credit ratings accorded by S&P and Moody's are not recommendations to purchase, hold or sell securities and such ratings do not comment as to market price or suitability for a particular investor. There is no assurance that any rating will remain in effect for any given period of time or that any rating will not be revised or withdrawn entirely by a rating agency in the future if in its judgment circumstances so warrant.

The Company has paid each of S&P and Moody's their customary fees in connection with the provision of the above credit ratings. The Company has not made any payments to S&P and Moody's unrelated to the provision of such ratings.

DIVIDENDS

Lightstream's policy is to use a portion of excess cash generated from operations to pay monthly dividends to shareholders, as well as to retain a portion of cash flow to fund new and ongoing development and optimization projects. The amount of cash dividends to be paid on the Common Shares, if any, is subject to the discretion of the Board and may vary depending on a variety of factors, including fluctuations in commodity prices, production levels, capital expenditure requirements, debt service requirements, operating costs, foreign exchange rates, the satisfaction of the liquidity and solvency tests imposed by the ABCA for the declaration and payment of dividends and compliance with the agreements governing the Company's Credit Facility, Unsecured Notes and Secured Notes. In January 2015, in response to the continued low WTI oil prices, we announced the suspension of our dividend program.

The following table sets forth the amount of monthly cash dividends paid per Common Share by the Company for the periods indicated.

Period	Dividend per Common Share
January 2012 – December 2012	$0.08
January 2013 – November 2013	$0.08
December 2013 – November 2014	$0.04
December 2014	$0.015
January 2015 – December 2015	--

MARKET FOR SECURITIES

Lightstream's Common Shares are listed for trading through the facilities of the TSX under the trading symbol "LTS". The table below sets forth the reported high and low monthly sales prices and the trading volumes of the Common Shares on the TSX during 2015.

Month	Price Range ($) High	Price Range ($) Low	Monthly Volume
January	1.26	0.64	32,144,287
February	1.81	0.79	56,365,279
March	1.25	0.85	36,809,921
April	1.42	0.90	29,008,899
May	1.62	1.03	28,139,777
June	1.20	0.92	21,152,725
July	1.02	0.59	14,699,765
August	0.69	0.30	19,730,236
September	0.54	0.35	18,449,560
October	0.53	0.37	20,694,980
November	0.44	0.33	13,767,287
December	0.35	0.21	11,106,316

DIRECTORS AND OFFICERS

The name, municipality of residence, position and principal occupation of each of the directors and senior officers of Lightstream, as of the date of this Annual Information Form, are as follows:

Name and Municipality of Residence	Positions Held[6]	Principal Occupation During Last Five Years
Annie Belecki Alberta, Canada	General Counsel	General Counsel of Lightstream since June 2014. Prior thereto, Associate General Counsel and Senior Legal Counsel at TransCanada Corporation (energy company) from September 2006 to June 2014 and Corporate Secretary of its U.S. affiliate, TC Pipelines L.P. from April 2012 to June 2014.
Ian S. Brown[1][4] Alberta, Canada	Director since October 2009	Independent businessman and corporate director.
Mary Bulmer, Alberta, Canada	Vice President, Corporate Services	Vice President, Corporate Services of Lightstream since May 2010.
Lawrence Fisher Alberta, Canada	Vice President, Land	Vice President, Land of Lightstream since May 2010.

Name and Municipality of Residence	Positions Held[6]	Principal Occupation During Last Five Years
Andrea Hatzinikolas Alberta, Canada	Corporate Secretary	Vice President, Corporate and Legal of Alvopetro Energy Ltd. (energy company) since November 2013. Prior thereto, Vice President, Business Development, General Counsel and Corporate Secretary of Petrominerales Ltd. (energy company) from May 2011 to November 2013. Assistant Corporate Secretary and General Counsel of Petrobank Energy and Resources Ltd. (energy company) from February 2007 to May 2011.
Peter Hawkes Alberta, Canada	Vice President, Geosciences	Vice President, Geosciences of Lightstream since September 2012. Prior thereto, Vice President, Exploration of Lightstream from October 2009 to September 2012.
Martin Hislop[1][3] Alberta, Canada	Director since October 2009	Independent businessman and corporate director.
Rene LaPrade, Alberta, Canada	Senior Vice President and Chief Operating Officer	Senior Vice President and Chief Operating Officer of Lightstream since January 2013. Prior thereto, Senior Vice President, Operations of Lightstream from September 2009 to December 2012.
Brad Malley Alberta, Canada	Vice President, Development Services	Vice President, Development Services since February 2015 and Vice President, Drilling and Completions of Lightstream from January 2013 to February 2015. Prior thereto, General Manager of Drilling and Completions of Lightstream from December 2010 to December 2012.
Kenneth R. McKinnon[1][3][4][5] Alberta, Canada	Director since October 2009	Partner at Citrus Capital Partners Ltd. (investment firm) since January 2014. Vice President Legal and General Counsel of Critical Mass Inc. (website design company) from March 2000 to December 2014.
Corey C. Ruttan[1][2][4] Alberta, Canada	Director since July 2009	President and Chief Executive Officer of Alvopetro Energy Ltd. (energy company) since November 2013. Prior thereto, President and Chief Executive Officer of Petrominerales Ltd. (energy company) from May 2010 to November 2013.
Doreen M. Scheidt Alberta, Canada	Vice President and Controller	Vice President and Controller of Lightstream since January 2013 and Controller of Lightstream from October 2009 to December 2012.
Peter D. Scott Alberta, Canada	Senior Vice President and Chief Financial Officer	Senior Vice President and Chief Financial Officer of Lightstream since May 2010.
W. Brett Wilson[2][3] Alberta, Canada	Director since December 2011	Chairman of Canoe 'GO CANADA' Fund Corp. (mutual fund corporation) since July 2013 and Chairman of Prairie Merchant Corporation (private investment management company) since 1991.

Name and Municipality of Residence	Positions Held[6]	Principal Occupation During Last Five Years
John D. Wright[2] Alberta, Canada	President and Chief Executive Officer Director since July 2009	President and Chief Executive Officer of Lightstream since May 2011. Prior thereto, President and Chief Executive Officer, Chairman, and director of Petrobank Energy and Resources Ltd. (energy company) from March 2000 to May 2014.

Notes:

1. Member of the Audit Committee.
2. Member of the Reserves Committee.
3. Member of the Compensation Committee.
4. Member of the Governance and Nomination Committee.
5. Chairman of the Board of Directors.
6. The term of office of each director expires at the next annual meeting of shareholders.

As at March 29, 2016, the directors and executive officers of Lightstream, as a group, beneficially owned or exercised control or direction over 10,109,752 Common Shares constituting approximately 5.09% of the issued and outstanding Common Shares.

CEASE TRADE ORDERS, BANKRUPTCIES, PENALTIES OR SANCTIONS

Except as disclosed herein, to the knowledge of the Company:

(a) no director or executive officer of the Company is as at the date hereof or was within the 10 years prior to the date hereof, a director, chief executive officer or chief financial officer of any company (including Lightstream) that was subject to a cease trade order or similar order or an order that denied the relevant company access to any exemption under securities legislation that was in effect for a period of more than 30 consecutive days and (i) was issued while the director or executive officer was acting in the capacity as director, chief executive officer or chief financial officer, or (ii) was issued after the director or executive officer ceased to be a director, chief executive officer or chief financial officer and resulted from an event that occurred while that person was acting in the capacity as director, chief executive officer or chief financial officer;

(b) no director or executive officer of the Company and no security holder holding a sufficient number of securities of the Company to affect materially the control of the Company, has been subject to (i) any penalties or sanctions imposed by a court relating to securities legislation or by a securities regulatory authority or has entered into a settlement agreement with a securities regulatory authority, or (ii) any other penalties or sanctions imposed by a court or regulatory body that would likely be considered important to a reasonable investor in making an investment decision;

(c) no director or executive officer of the Company and no security holder holding a sufficient number of securities of the Company to affect materially the control of the Company is or has been within the 10 years preceding the date hereof, a director or executive officer of any company, that while that person was acting in that capacity, or within a year of that person ceasing to act in that capacity, became bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets; and

(d) in addition, no director or executive officer or securityholder holding a sufficient number of securities of the Company to affect materially the control of the Company has, within the last 10 years prior to the date hereof, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or become subject to or instituted any proceedings, arrangement or compromise with creditors, or had a receiver, receiver manager or trustee appointed to hold the assets of the director, executive officer or securityholder.

Rene LaPrade

On April 30, 2008, a management cease trade order ("**MCTO**") was issued by the Alberta Securities Commission ("**ASC**") in respect of Sahara Energy Ltd. ("**Sahara**"), a reporting issuer listed on the TSX Venture Exchange. The MCTO was issued against Sahara for failure to file annual audited financial statements for the year ended December 31, 2007 (the "**Unfiled Statements**"). The MCTO prohibited certain directors and officers of Sahara, including Mr. Rene LaPrade (a director of Sahara), from trading in securities of Sahara until two business days following the filing of the Unfiled Statements with the ASC or until the MCTO was revoked. The MCTO expired on June 17, 2008.

On January 8, 2009, Mr. Rene LaPrade entered into a settlement agreement with the ASC in respect of an insider trading violation relating to a February 6, 2008 trade. Mr. LaPrade cooperated fully with the ASC in resolving the matter. Mr. LaPrade paid $10,000 in settlement of the allegations against him and costs of the investigation in the amount of $500. As part of the settlement agreement, Mr. LaPrade agreed to cease trading in securities (subject to certain exceptions) and to refrain from acting as a director of any issuer until January 8, 2010.

Corey C. Ruttan

Mr. Corey C. Ruttan entered into a settlement agreement with the ASC on May 3, 2002 in respect of an insider trading violation relating to a May 17, 2000 trade. Mr. Ruttan cooperated completely in resolving the matter with the regulators. The settlement resulted in Mr. Ruttan paying an administrative penalty of $10,000, representing a return of profits, and the costs of the proceeding in the amount of $3,925. For a period of one year until May 3, 2003, Mr. Ruttan agreed to cease trading in securities and to not act as a director or officer of a public company. Mr. Ruttan is a Chartered Accountant in good standing.

Peter D. Scott

Mr. Peter D. Scott was a director of Shoreline Energy Corp. ("**Shoreline**"), a reporting issuer listed on the Toronto Stock Exchange, when Shoreline obtained protection under the *Companies' Creditor Arrangement Act* (Canada) on April 13, 2015. Shorline's securities were halted from trading on April 14, 2015 and delisted on May 14, 2015. On May 22, 2015 Shoreline received cease trade orders from various provincial securities commissions for failure to file interim unaudited financial statements, management discussion and analysis and certifications of interim filings for the period ended March 31, 2015. The filings were made on June 26, 2015 and all cease trade orders were lifted by August 25, 2015. On December 23, 2015 all directors and officers resigned from Shoreline when it filed an assignment under the *Bankruptcy and Insolvency Act* (Canada).

John D. Wright

Mr. John D. Wright was a director of Canadian Energy Exploration Inc. ("**CEE**") (formerly TALON International Energy, Ltd.), a reporting issuer listed on the TSX Venture Exchange, until September 15, 2011. A cease trade order (the "**ASC Order**") was issued on May 7, 2008 against CEE by the ASC for the delayed filing of CEE's audited annual financial statements and management's discussion and analysis for the year ended December 31, 2007 ("**2007 Annual Filings**"). The 2007 Annual Filings were filed by CEE on SEDAR on May 8, 2008. As a result of the ASC Order, the TSX Venture Exchange suspended trading in CEE's shares on May 7, 2008. In addition, on June 4, 2009 the British Columbia Securities Commission ("**BCSC**") issued a cease trade order (the "**BCSC Order**") against CEE for the failure of CEE to file its audited annual financial statements and management's discussion and analysis for the year ended December 31, 2008 (the "**2008 Annual Filings**") and its unaudited interim financial statements and management's discussion and analysis for the three months ended March 31, 2009 (the "**2009 Interim Filings**"). The 2008 Annual Filings and the 2009 Interim Filings were filed by CEE on SEDAR on October 9, 2009.

CEE made application to the ASC and BCSC for revocation of the ASC Order and BCSC Order. The ASC and BCSC issued revocation orders dated October 14, 2009 and November 30, 2009, respectively, granting full revocation of compliance-related cease trade orders issued by the ASC and the BCSC in respect of CEE.

Mr. John D. Wright was a director of Spyglass Resources Corp. ("**Spyglass**"), a reporting issuer listed on the Toronto Stock Exchange, until November 26, 2015, when Spyglass was placed into receivership by the Court of Queen's Bench of Alberta following an application by its creditors.

INDUSTRY CONDITIONS

Companies operating in the oil and natural gas industry are subject to extensive control and regulation governing their operations, including land tenure, exploration, development, production, marketing, transportation, and refining, through legislation enacted by various levels of government. In addition, pricing and taxation of oil and natural gas are governed by agreements among the governments of Canada, British Columbia, Alberta and Saskatchewan. It is not expected that any of these controls or regulations will affect the operations of Lightstream in a manner materially different than they would affect other oil and gas companies of a similar size. All current legislation is a matter of public record and Lightstream is unable to predict what additional legislation or amendments may be enacted. Outlined below are some of the principal aspects of legislation, regulations and agreements governing the oil and gas industry.

Land Tenure

Crude oil and natural gas located in British Columbia, Alberta and Saskatchewan are owned predominantly by the respective provincial governments, generally termed the "Crown". Provincial governments grant rights to explore for and produce oil and natural gas under leases, licenses and permits with terms generally varying from two years to five years and on conditions contained in provincial legislation. Leases, licenses and permits may be continued indefinitely by producing under the lease, license or permit. Some of the oil and natural gas located in these provinces is freehold (privately owned) and rights to explore for and produce oil and natural gas are granted by the respective mineral owners on negotiated terms and conditions on a lease-by-lease basis.

Pricing and Marketing – Crude Oil

In Canada, producers of oil negotiate sales contracts directly with oil purchasers, with the result that the market determines the price of oil. Worldwide supply and demand factors primarily determine oil prices, however, prices are also influenced by regional market and transportation issues. The price depends in part on world market forces (OPEC, and hostilities in the middle east and other regions around the world), the oil type, oil quality, prices of competing oil types, distance to market, availability and cost of transportation capacity to various markets, the value of refined products and the supply/demand balance. Oil exports may be made pursuant to export contracts with terms not exceeding one year in the case of crude oil other than heavy crude oil, and not exceeding two years in the case of heavy crude oil, provided that an order approving any such export has been obtained from the National Energy Board ("**NEB**"). Any crude oil export to be made pursuant to a contract of longer duration (to a maximum of 25 years) requires an exporter to obtain an export license from the NEB and the issue of such a license requires the approval of the Governor in Council.

Pricing and Marketing – Natural Gas

In Canada, natural gas is sold throughout the country and in the United States at various market hubs, which are connected to pipelines within Canada and the United States. The transaction price is determined by negotiation between natural gas producers, marketers and purchasers, and includes the utilization of electronic trading platforms, various publications and reference indices. Prices depend on many variables including but not limited to supply and demand fundamentals, the price of New York Mercantile Exchange natural gas contracts, distance to alternate markets, pipeline transportation costs, natural gas storage levels, competing fuels, contract terms, weather, and foreign currency exchange. Natural gas exported from Canada is subject to regulation by the NEB and the Government of Canada. Exporters can negotiate prices and other terms with purchasers, provided that the export contracts must continue to meet certain criteria prescribed by the NEB and the Government of Canada. As in the case with oil, natural gas exported from Canada for a term of two years or less or for a term of between two and 20 years (in quantities of not more than 30,000 10^3m^3 per day) may be made pursuant to a NEB order, or, in the case of exports for a longer duration (to a maximum of 25 years) or a larger quantity, pursuant to an NEB export license and Governor in Council approval.

The governments of British Columbia, Alberta and Saskatchewan regulate the volume of natural gas that may be removed from those provinces based on such factors as reserve availability, transportation arrangements and market considerations.

Royalties and Incentives

General

In addition to federal regulation, each province has legislation and regulations which govern land tenure, royalties, production rates, environmental protection and other matters. In all provincial jurisdictions where we operate, producers of oil and natural gas are required to pay annual rental payments in respect of Crown leases and royalties and freehold production taxes in respect of oil and natural gas produced from Crown and freehold lands, respectively. The royalty regime in a given province is a significant factor in the profitability of crude oil and natural gas production. Royalties payable on production from lands, other than Crown lands, are determined by negotiations between the mineral freehold owner and the lessee, although production from such lands is also subject to certain provincial taxes and royalties. Crown royalties are determined by governmental regulation and are generally calculated as a percentage of the value of gross production and the rate of royalties payable generally depends in part on prescribed reference prices, well productivity, geographical location, field discovery date, method of recovery and the type or quality of the petroleum product produced. Other royalties and royalty-like interests are, from time to time, carved out of the working interest owner's interest through non-public transactions. These are often referred to as overriding royalties, gross overriding royalties, net profits interests or net carried interests.

From time to time, the governments of Canada, British Columbia, Alberta and Saskatchewan have established incentive programs which have included royalty rate reductions, royalty holidays or tax credits for the purpose of encouraging oil and natural gas exploration or enhanced planning projects. Such programs are generally introduced when commodity prices are low, and are designed to encourage exploration and development activity by improving project economics. These programs reduce the amount of Crown royalties otherwise payable.

Alberta

Currently, producers of oil and gas from Crown lands in Alberta are required to pay annual rental payments at a rate of $3.50 per hectare, and make monthly royalty payments in respect of oil and natural gas produced.

Royalties are currently paid pursuant to "The New Royalty Framework" (implemented by the *Mines and Minerals (New Royalty Framework) Amendment Act, 2008*) and the "Alberta Royalty Framework", which was implemented in 2010. Royalty rates for conventional oil are set by a single sliding rate formula, which is applied monthly and incorporates separate variables to account for production rates and market prices. The maximum royalty payable under the royalty regime is 40 percent. Royalty rates for natural gas under the royalty regime are similarly determined using a single sliding rate formula with the maximum royalty payable under the royalty regime set at 36 percent.

Producers of oil and natural gas from freehold lands in Alberta are required to pay freehold mineral tax. The freehold mineral tax is a tax levied by the Government of Alberta on the value of oil and natural gas production from non-Crown lands and is derived from the *Freehold Mineral Rights Tax Act* (Alberta). The freehold mineral tax is levied on an annual basis on calendar year production using a tax formula that takes into consideration, among other things, the amount of production, the hours of production, the value of each unit of production, the tax rate and the percentages that the owners hold in the title. On average, the tax levied is four percent of revenues reported from fee simple mineral title properties.

The Government of Alberta has from time to time implemented drilling credits, incentives or transitional royalty programs to encourage oil and gas development and new drilling. For example, the Innovative Energy Technologies Program ("IETP"), which is currently in place, has the stated objectives of increasing recovery from oil and gas deposits, finding technical solutions to the gas over bitumen issue, improving the recovery of bitumen by in-situ and mining techniques and improving the recovery of natural gas from coal seams. The IETP provides royalty adjustments to specific pilot and demonstration projects that utilize new or innovative technologies to increase recovery from existing reserves.

In addition, the Government of Alberta has implemented the "Emerging Resources and Technology Initiative" intended to accelerate technological development and facilitate the development of unconventional resources, specifically:

- Coalbed methane wells receive a maximum royalty rate of five percent for 36 producing months on up to 750 MMcf of production, retroactive to wells that began producing on or after May 1, 2010;

- Shale gas wells receive a maximum royalty rate of five percent for 36 producing months with no limitation on production volume, retroactive to wells that began producing on or after May 1, 2010;

- Horizontal gas wells receive a maximum royalty rate of five percent for 18 producing months on up to 500 MMcf of production, retroactive to wells that commenced drilling on or after May 1, 2010; and

- Horizontal oil wells and horizontal non-project oil sands wells receive a maximum royalty rate of five percent with volume and production month limits set according to the depth of the well (including the horizontal distance), retroactive to wells that commenced drilling on or after May 1, 2010.

On January 29, 2016, the Government of Alberta announced a summary of a Modernized Royalty Framework ("MRF") which is based on the recommendations of a government-appointed royalty review advisory panel. The review panel's main findings and recommendations which were accepted by the government include:

- For oil, natural gas and NGLs, existing wells will continue to be governed by the current royalty system for the next 10 years, during which period existing royalty rates will be grandfathered, and the MRF will apply to wells drilled starting January 1, 2017.

- For wells to which the MRF applies, there will be three separate phases. Companies will pay a flat 5% royalty until well payout based on a revenue minus cost structure is completed. A drilling and completion cost allowance formula administered by the Province of Alberta, that will include any applicable carbon levies, will provide the capital costs of wells for payout purposes. These costs will reflect the depth and, for horizontal wells, the length of the wells drilled and will be calibrated annually.

- Royalties paid based on revenues on all production streams (oil, natural gas and NGLs) will be harmonized under the new program.

- Post-payout, there will be two other phases:

    - The Mid-life phase where royalties are strictly tied to commodity prices. These post payout royalty rates will be higher than the 5% flat rate that applies before payout and will be intended on average to yield the same internal rate of return as under the current royalty system. The post payout royalty rates are expected to be announced on March 31, 2016.

  - When a Maturity threshold is hit (20 bbl/ d for oil and 200 mcf/d for natural gas), royalty rates will move to a sliding scale (based on volume and price) with a 5% minimum, acknowledging that lower rate older wells have higher unit costs. This arrangement is intended to delay premature shut-ins of wells that are no longer economic under Mid-life period royalties.

- Current drilling incentives that were set to expire in 2016 will be extended and built into the MRF. The effect of those drilling incentives will diminish in a high price environment.

- The Government should look into creating incentives for EOR and high risk experimental drilling.

Details of the MRF, including applicable royalty rates and the cost allowance formula, are to be finalized by the Government in consultation with stakeholders by March 31, 2016.

Saskatchewan

In Saskatchewan, crude oil Crown royalties and freehold production tax depend on well productivity, the current market price of oil, the classification and vintage of the oil and the quantity of oil produced in a month. Crude oil is classified as "heavy oil", "southwest designated oil" or "non-heavy oil other than southwest designated oil", and the vintage classifications ("fourth tier oil", "third tier oil", "new oil" or "old oil") are applicable to each of these three crude oil types. Generally, the vintage of oil is based on the determination of whether the well was on production before January 1, 1974 ("**old oil**"), drilled between February 9, 1998 and October 1, 2002 ("**new oil**"), between January 1, 1974 (April 1, 1991 if horizontal) and January 1, 1994 (October 1, 2002 if horizontal) ("**third tier oil**"), or after October 1, 2002 ("**fourth tier oil**"). Newly drilled oil wells in Saskatchewan qualify for "volume based" incentives ranging from 0 to 16,000 m3, depending on the type of well (deep or non-deep, exploratory or development, and horizontal or vertical). Qualifying incentive volumes are subject to a maximum royalty rate of 2.5% and a freehold production tax rate of 0%.

Saskatchewan Crown royalties and freehold production tax on natural gas are price sensitive, depending also on the vintage of the natural gas, the quantity produced in a month, and whether the gas is associated (gas produced from oil wells) or non-associated. The vintage classifications of gas production are "fourth tier gas", "third tier gas", "new gas" and "old gas". Generally, the vintage of gas is based on the determination of whether the gas is produced from a well on production before October 1, 1976 ("**old gas**"), drilled between October 1, 1976 and February 9, 1998 ("**new gas**"), between February 9, 1998 and October 1, 2002 ("**third tier gas**"), or after October 1, 2002 ("**fourth tier gas**"). Newly drilled qualifying exploratory gas wells in Saskatchewan qualify for a 25,000,000 m3 "volume based" incentive. The qualifying incentive volume is subject to a maximum Crown royalty rate of 2.5% and a freehold production tax rate of 0%.

The majority of Lightstream's production in Saskatchewan is "non-heavy oil other than southwest designated oil" with a vintage classification of "fourth tier oil". Saskatchewan royalty payable on this production is typically 2.5% until 6,000 m3 (37,740 barrels) of oil have been produced. Production in excess of this threshold is subject to a royalty rate based on well productivity and oil prices. The maximum royalty rate for all fourth tier oil is 30%.

In addition, oil produced from EOR projects (excluding waterflood projects) that commenced operation on or after April 1, 2005 are subject to a cost sensitive royalty regime that provides a royalty of 1% of gross EOR revenue prior to project payout and 20% of EOR operating income after project payout and a freehold production tax rate of 0% prior to payout and 8% of EOR operating income after payout.

The majority of Lightstream's gas production in Saskatchewan is "associated gas" which is natural gas produced in association with oil. As an incentive for the production and marketing of natural gas which could otherwise have been flared, the royalty rate for associated gas is less than on non-associated natural gas. The maximum royalty rate for all fourth tier gas is 30%.

British Columbia

Producers of oil and natural gas in British Columbia are required to pay royalties and freehold production taxes in respect of oil and gas produced from Crown and freehold lands, respectively. The amount payable as a royalty in respect of oil depends on the vintage of the oil pool discovery (whether the oil was produced from a pool discovered before or after October 31, 1975), whether the oil is considered incremental or produced from a well shut-in for at least 36 months immediately preceding January 1, 1998 and which resumed production on or after such date, the quantity of oil produced in a month and the value of the oil. Oil produced from pools discovered after June 30, 1974 may be exempt from the payment of a royalty for the first 36 months of production. Subject to minimum royalties described in the following sentence, the royalty payable on natural gas is determined by a sliding scale based on a reference price which is the greater of the amount obtained by the producer and at prescribed minimum price. Gas produced in association with oil has a minimum royalty of 8%, while the royalty in respect of other gas may not be less than 15%.

British Columbia Crown natural gas basic royalty with respect to gas typical of new drilling prospects, ranges from 9% to 27%, based on gas price. Low productivity wells, marginal wells and ultra marginal wells will have their royalties reduced and will approach 0% as the production rate approaches zero. During 2008, the Deep Well Program was extended, which provides royalty credits for wells with vertical depths greater than 2,500 meters, or for horizontal wells with completion point vertical depth greater than 2,300 meters. Royalty credit ranges from zero at 2,500 meters to $2.7 million at a depth of 5,500 meters for wells located in the east map area of northeast British Columbia, where we own significant mineral rights.

Environmental Regulation

All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to international conventions and national, provincial, and municipal laws and regulations. Environmental legislation provides for, among other things, restrictions and prohibitions for spills, releases, discharges, or emissions of various substances produced or used in association with oil and natural gas operations, as well as requirements for oilfield waste handling and storage and disposal, land reclamation, habitat protection, and minimum setbacks of oil and natural gas activities from surface water bodies.

Environmental legislation in the Province of Alberta is, for the most part, set out in the *Environmental Protection and Enhancement Act* and *The Oil and Gas Conservation Act*, which impose strict environmental standards with respect to the releases of effluent and emissions, including monitoring and reporting obligations, and impose significant penalties for non-compliance. For example, regulations enacted thereunder target sulphur dioxide and nitrous oxide emissions from oil and gas operations. The Alberta Energy Regulator ("AER") is responsible for the administration of both the *Environmental Protection and Enhancement Act* and *The Oil and Gas Conservation Act*.

Environmental legislation in the Province of Saskatchewan is, for the most part, set out in the *Environmental Management and Protection Act, 2002* and *The Oil and Gas Conservation Act*, which regulate harmful or potentially harmful activities and substances, any release of such substances and remediation obligations. Certain development activities in Saskatchewan, depending on the location and potential environmental impact, may require a screening or an environmental impact assessment under the provincial *Environmental Assessment Act*. In In addition, in June 2015, the Saskatchewan Environmental Code ("SEC") came into full effect. The SEC addresses specific activities and standards under current environmental legislation as well as introduces new regulations for the management of greenhouse gases ("GHGs").

Environmental legislation in the Province of British Columbia is, for the most part, set out in the *Environmental Management Act* (the "EMA"), the *Oil and Gas Activities Act* and the *Petroleum and Natural Gas Act*, which regulate the storage, discharge and disposal of air contaminants, effluent and hazardous waste into the environment. Specifically, the Oil and Gas Waste Regulation under the EMA regulates hydrogen sulphide and nitrogen oxide emissions from oil and natural gas facilities. The EMA provides for the imposition of significant penalties in the event of non-compliance with regulations and standards and sets the criteria for the remediation of contaminated sites. New oil and natural gas projects, or modifications to existing projects, may be subject to a review under the *Environmental Assessment Act*.

Environmental legislation also requires wells and facility sites to be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. Compliance with such legislation can require significant expenditures and a breach may result in the imposition of significant fines and penalties, some of which may be material, or in the suspension or revocation of necessary licenses and approvals. Lightstream may also be subject to civil liability for damage caused by pollution. Certain environmental protection legislation may subject us to statutory strict liability in the event of an accidental spill or discharge from a licensed facility, meaning that fault on our part need not be established if such a spill or discharge is found to have occurred. See "*Additional Information Concerning Abandonment and Reclamation Costs*" for an estimate of our abandonment and reclamation costs as at December 31, 2015.

Greenhouse Gases and Industrial Air Pollutants

Canada

Climate change arrived on the international stage at the Rio Earth Summit in 1992, where 154 countries signed the United Nations Framework Convention on Climate Change ("**UNFCCC**") to stabilize atmospheric concentrations of GHG emissions at a level to prevent "dangerous anthropogenic interference with the climate system". The UNFCCC entered into force on March 21, 1994 and 195 countries have ratified the UNFCCC to date. Subsequent international negotiations led to the Kyoto Protocol, an international treaty which extends the UNFCCC and commits its signatories to reduce GHG emissions. The Kyoto Protocol was adopted in December 1997 and came into force on February 16, 2005. There are currently 192 signatories to the Kyoto Protocol. While Canada withdrew from the Kyoto Protocol effective December 2012, a newly elected federal government has indicated its willingness to re-engage in international talks to reach a new global climate change treaty for the post-Kyoto era.

The latest round of international climate change talks held in late 2015 by the Conference of the Parties to the UNFCCC resulted in the adoption of the Paris Agreement by 195 member nations of the UNFCCC. The Paris Agreement, which contains both binding and non-binding commitments, will enter into force 30 days after the date on which at least 55 parties to the UNFCCC, accounting for at least 55% of total global GHG emissions, deposit their instruments of ratification, acceptance, approval or accession. As noted above, the Paris Agreement aims to hold the increase in global average temperature to well below 2°C above pre-industrial levels, while countries pursue efforts to limit the temperature increase to 1.5°C above pre-industrial levels. In addition, the Paris Agreement articulates a series of global goals to enhance climate adaptation efforts and capacity-building, as well as strengthen resilience and reduce vulnerability to climate change. Beyond the temperature limit, the Paris Agreement also establishes a long-term emissions goal of peaking global GHG emissions as soon as possible, with a view to achieving a balance between anthropogenic emissions by sources and removals by sinks of GHG emissions in the second half of this century. In 2018, member parties will convene a facilitative dialogue to assess their collective efforts in relation to their progress towards the long-term goal. The outcomes of this dialogue will likely inform future climate policies and actions.

In May 2015, Canada submitted its Intended Nationally Determined Contribution ("**INDC**") to the UNFCCC Secretariat, pledging a 30% reduction on GHGs from 2005 levels – approximately 523 Mt – by 2030. In its Sixth National Report on Climate Change, Environment Canada projected Canada's emissions to be 815 Mt CO_2e, or 11% above 2005 levels, with current measures in place. Given the overall increase in Canada's emissions over the past two decades and continuing upwards trajectory, achieving Canada's INDC will require ambitious federal and provincial policies. Canada's federal Liberal government is expected to update the INDC and further consult with the provinces and territories. As a result, it is widely expected that a new federal climate change strategy will call for more stringent targets and actions. As the details of the implementation of any federal legislation for GHGs have not been announced, the effect on our operations cannot be determined at this time.

In March 2004, the federal government announced the introduction of the Greenhouse Gas Emissions Reporting Program, which applies to large industrial GHG emitters in Canada. All facilities that emit the equivalent of 50,000 tonnes or more of CO2e per year are required to submit a report to Environment Canada. Facilities with emissions below the reporting threshold of 50,000 tonnes per year can voluntarily report their GHG emissions. The Company voluntarily reports emissions under this legislation.

Alberta

With the election of a New Democratic Party government in Alberta in May 2015, there was a shift in Alberta's approach to climate change. In November 2015, the Alberta government announced its Climate Leadership Plan (the "**Plan**") and released to the public the Climate Leadership Report to Minister (the "**Report**") which it commissioned from the Climate Change Advisory Panel. While details of the Plan's implementation and the extent to which the government adopts the specific recommendations of the Report remain to be seen, the key policies of the Plan as they relate to the conventional oil and gas industry include: an Alberta economy-wide price on GHG emissions of $30/tonne; and a methane reduction strategy to address methane emissions in the oil and gas sector.

Central to the Plan is broad-based carbon pricing based on the Panel's proposal to replace the existing emission intensity based *Specified Gas Emitters Regulation* ("**SGER**") with a *Carbon Competitiveness Regulation* ("**CCR**"). Under the proposed CCR: (1) The price of carbon in 2017 will be $20/tonne, escalating to $30/tonne by 2018, with the potential for annual increases equal to inflation plus two percent, depending on the cost of carbon in competing jurisdictions; (2) elements of cap and trade and carbon tax regimes are used, depending on the type of GHG emissions, which fall into two basic groups: emissions from large industrial emitters and end-use emissions; large industrial emitters consist of facilities that emit more than 100,000 tonnes of GHG emissions annually, as well as aggregated oil and gas production facilities or gas processing plants whose GHG emissions do not meet such threshold but who choose to opt-in to such regime. Large emitters are to be allocated emissions permits based on sector specific top-quartile performance with such allocations decreasing at a rate of one to two percent annually to account for expected energy efficiency improvements. End-use emissions are characterized as GHG emissions from the combustion of transportation and heating fuels.

Noting that the climate change impact of methane is 25 times greater than carbon dioxide over a 100-year period, the Plan contemplates a 45-percent reduction in methane emissions in Alberta by 2025. Under the Plan: (1) new methane emissions design standards will be created and applied to new oil and gas facilities; (2) a five-year voluntary Joint Initiative on Methane Reduction and Verification will be implemented with industry and other groups, tasked with improving standards for venting and fugitive emissions from existing and new facilities, including through improved measurement and reporting requirements; and (3) on-site combustion (i.e., flaring) at conventional oil and gas facilities will be subject to the carbon pricing regime starting in 2023.

Until Alberta climate policies are better defined, including output-based allocations and regulatory standards, we cannot accurately predict the cost of compliance with these initiatives on the Company's operations.

Currently in Alberta, GHG emissions are regulated under the SGER pursuant to the *Climate Change and Emissions Management Act*. In June 2015, the Alberta government increased the emissions reduction targets for regulated emitters to 15% in 2016 and 20% in 2017 below an average baseline taken from a facility's 2003 - 2006 emissions. Companies may meet requirements through improvements to their operations by purchasing Alberta based emission reduction credits or by contributing to the provincial Climate Change and Emissions Management Fund. Lightstream does not currently operate any facilities that are regulated by the Alberta GHG emissions regulations.

British Columbia

In 2007, the Government of British Columbia legislated targets for reducing GHG emissions in the *Greenhouse Gas Reduction Targets Act* (the "**Cap and Trade Act**"). BC has pledged to reduce provincial emissions by 33% below 2007 levels by 2020 and 80% below 2007 levels by 2050. Supporting this legislation was the 2008 Climate Action Plan, which set out a range of the climate actions to be taken across all sectors of the economy. Three of the more prominent policies included the introduction of a revenue neutral carbon tax, a carbon neutral government initiative and the implementation of a low carbon fuel standard.

The reporting regulation, implemented under the authority of the Cap and Trade Act sets out the requirements for the reporting of the GHG emissions from facilities in British Columbia emitting 10,000 tonnes or more of carbon dioxide equivalent emissions per year beginning on January 1, 2010. Those reporting operations with emissions of 25,000 tonnes or greater are required to have emissions reports verified by a third party. Emissions include flaring and carbon dioxide from natural gas fuel consumption. Lightstream currently reports under the British Columbia regulations with respect to three of our facilities and associated wells.

In November 2014, the BC government passed the *Greenhouse Gas Industrial Reporting and Control Act* (the "**GGIRC Act**") for the management of GHG emissions from the province's liquefied natural gas (LNG) industry. The GGIRC Act seeks to establish a GHG emissions intensity benchmark for LNG produced and also streamlines several aspects of existing GHG legislation and regulations into a single legislative and regulatory system. As a result, the existing reporting regulation will be replaced by a new regulation expected to come into force for the 2016 reporting year.

In May 2015, BC Premier Christy Clark introduced a Climate Leadership Team that has been tasked with developing a Climate Leadership Plan, which will update and build on the province's current Climate Action Plan. The Climate Leadership Team's mandate is to provide advice and recommendations on updating the 2008 Climate Action Plan and actions to achieve further emission reductions. On November 27, 2015, BC's government announced the Climate Leadership Team's Recommendations Report, which includes the following recommendations:

- establishing a legislated 2030 emissions reduction target of 40% below 2007 levels;
- establishing sectoral GHG reduction goals for the transportation, industrial and built environment sectors for 2030 (below 2015 levels);
- increasing the carbon tax by $10 per year commencing in July 2018, while maintaining current broad-based tax reductions;
- expanding coverage of the current carbon tax to apply to all GHG emission sources in BC after five years; and
- amending the *Environmental Assessment Act* to include the social cost of carbon in the environmental assessment process to ensure consistency with the climate action plan and carbon pricing signals.

Further public consultations will take place in January 2016, and it is expected that a new Climate Leadership Plan will be finalized in March 2016.

Saskatchewan

In May 2009, the Government of Saskatchewan announced *The Management and Reduction of Greenhouse Gases Act* (the "**MRGGA**") to regulate GHG emissions in the province. The MRGGA has received royal assent but has not yet been proclaimed and so is not yet in force. The MRGGA established a framework for achieving the provincial target of a 20% reduction in GHG emissions from 2006 levels by 2020. It remains unclear to what degree a scheme implemented under the MRGGA will affect Lightstream.

The Future of GHG Emission Regulations

There will most certainly be a financial impact of GHG emission regulation on oil and gas industry participants and their projects. However, the extent of that impact is not yet known. In particular, there is uncertainty regarding the ultimate GHG emission regulatory regime that will be applicable to us due to a variety of factors, including the potential for changes to the regulation of GHG emissions and the potential for the harmonization of GHG emission regulatory regimes across various jurisdictions, which may impact our operations.

At present, there is no assurance that any new regulations implemented by the Government of Canada relating to the reduction of GHG emissions will be harmonized with the Government of Alberta's GHG emissions reduction regulations. In such case, the costs of meeting new federal government requirements could be considerably higher than the costs of meeting Alberta's current requirements.

Hydraulic Fracturing

The proliferation of the use of hydraulic fracturing as a recovery technique employed in oil and natural gas drilling has given rise to increased public scrutiny of its environmental aspects, particularly with respect to its potential impact on local aquifers. Lightstream utilizes hydraulic fracturing in a significant portion of the light oil wells it drills and completes. Lightstream believes that the hydraulic fracturing that we conduct, given the depth and location of the wells and our consistent utilization of good oilfield practices, is environmentally sound in general and would not give rise to concerns raised respecting local aquifers. Lightstream anticipates that there will be a trend towards increased regulatory requirements concerning hydraulic fracturing in the future.

Fugitive Gas Emissions in Saskatchewan

The Saskatchewan Ministry of the Economy enacted a Minister's Order in June of 2011 pursuant to *The Oil and Gas Conservation Act* requiring adherence to Directive S-10 - Saskatchewan Upstream Petroleum Industry Associated Gas Conservation Directive and Directive S-20 - Saskatchewan Upstream Flaring and Incineration Requirements (together, the "**Directives**"). Directive S-10 provides enforceable regulatory requirements for reducing flaring and venting of associated gas from upstream activity in the province and Directive S-20 provides for regulatory guidance as to gas flaring and incineration performance, equipment spacing and design and set-back requirements. The Directives were put in place to reduce fugitive emissions and ensure that upstream oil and gas facilities and wells are operated in a manner that does not result in air pollution that exceeds the ambient air quality standards prescribed by Saskatchewan Ministry of the Environment. Both Directives are effective on all licensed wells and facilities.

Trends

The operations of the Company are, and will continue to be, affected in varying degrees by laws and regulations regarding environmental protection. Lightstream believes it is likely that the trend in environmental legislation and regulation will continue toward stricter standards. It is impossible to predict the full impact of these laws and regulations on our operations. It is not anticipated that our competitive position will be adversely affected by current or future environmental laws and regulations governing our current oil and gas operations. No assurance can be given, however, that environmental or safety laws or regulations will not result in a curtailment of production, a material increase in the costs of production or development or exploration activities or otherwise adversely affect our projects, financial condition, capital expenditures, results of operations, competitive position or prospects. The Company is committed to meeting our responsibilities to protect the environment and the safety of our workers in all areas where we conduct operations and will take such steps as required to ensure compliance with environmental and safety legislation.

RISK FACTORS

The following risk factors, together with other information contained in this Annual Information Form, should be carefully considered before investing in the Company. Each of these risks may negatively affect the trading price of Lightstream's Common Shares and the amount, if any, of dividends that may from time to time be declared and paid to shareholders. If any of the following risks actually occur, Lightstream's business, financial condition and operating results could be materially and adversely affected. Additional risks are described under the heading "*Risks and Uncertainties*" in our Management's Discussion and Analysis for the year ended December 31, 2015.

Nature of the Business

An investment in Lightstream should be considered speculative due to the nature of the Company's involvement in the exploration for, and the acquisition, development and production of, oil and natural gas in Canada. Oil and gas operations involve many risks, which even a combination of experience and knowledge and careful evaluation may not be able to overcome. There is no assurance that further commercial quantities of oil and natural gas will be discovered or acquired by the Company.

Financial Resources and Indebtedness

The Company's cash from operations may not be sufficient to fund our ongoing activities, financial obligations and business plans. Our indebtedness limits our ability to pay future dividends to shareholders, and could affect the market price of the Common Shares. The agreements governing our Credit Facility, Secured Notes and Unsecured Notes provide that if we are in default under the Credit Facility, Secured Notes or Unsecured Notes or fail to comply with certain covenants, we must repay the indebtedness at an accelerated rate. If we are unable to pay the debt service charges or otherwise commit an event of default, such as bankruptcy, our lenders may receive a judgment and have a claim on our properties. The proceeds of any sale of properties would be applied to satisfy amounts owed to the creditors. Only after the proceeds of that sale were applied towards the debt would the remainder, if any, be available for distribution to shareholders.

Depending on future exploration and development plans, the Company may require additional financing, which may not be available or, if available, may not be available on favourable terms. Failure to obtain such financing on a timely basis could cause the Company to forfeit or forego various opportunities. Credit markets throughout the world may be restrictive, which could limit the Company's ability to access incremental debt. As at December 31, 2015, the Company had positive funds flows from operations and our Credit Facility had approximately $195 million of available capacity. Given the current economic environment, management expects the borrowing base under the Company's Credit Facility could be reduced at the next re-determination scheduled by April 30, 2016, thereby impacting our available credit capacity. In addition, as of the date hereof, Lightstream has Secured Notes outstanding having an aggregate principal amount of US$650 million, which mature June 2019 and Unsecured Notes outstanding having an aggregate principal amount of US$254 million, which mature February 2020.

The interest rate payable by Lightstream under our Credit Facility is not fixed. Any increase in interest rates would increase the amount that Lightstream pays to service our debt and a significant increase in interest rates may materially adversely affect Lightstream's financial results.

Share Price Volatility

The trading price of our Common Shares is subject to substantial volatility based on factors related and unrelated to our financial performance or prospects. Factors unrelated to our performance could include macroeconomic developments nationally, within North America or globally, domestic and global commodity prices or current perceptions of the oil and gas market. Similarly, the market price of our Common Shares could be subject to significant fluctuations in response to variations in our operating results, financial condition, liquidity and other internal factors. Factors that could affect the market price of our Common Shares that are unrelated to our performance include domestic and global commodity prices and market perceptions of the attractiveness of particular industries. The price at which our Common Shares will trade cannot be accurately predicted.

Commodity Price Volatility

The Company's results of operations and financial condition are dependent on the prices it receives for the oil and natural gas it produces and sells. Oil and natural gas prices have fluctuated widely during recent years and may continue to be volatile in the future. Oil and natural gas prices have decreased significantly since mid-2014 and have fluctuated in response to a variety of factors beyond the Company's control, including: global energy policy, including the ability of OPEC to set and maintain production levels for oil; geo-political conditions; worldwide economic conditions including ongoing credit and liquidity concerns; weather conditions including weather-related disruptions to the North American natural gas supply; the supply and price of foreign and North American produced oil and natural gas; the level of consumer demand; the price and availability of alternative fuels; the proximity to, and capacity of, transportation facilities; the effect of worldwide energy conservation measures; and government regulation.

The prices received by Lightstream for its oil are subject to differentials against such benchmarks as WTI and Edmonton Par which can fluctuate substantially and result in Lightstream realizing prices substantially below such benchmarks. North American crude oil price differentials are expected to continue to be volatile throughout 2016 which will have an impact on crude oil prices for Canadian producers. Overall, supply in excess of current pipeline and refining capacity is expected to exist. Material structural changes are required to reduce these bottlenecks and the resulting steep price discounts. There are numerous projects proposed to alleviate pipeline bottlenecks in the United States, expand refinery capacity and expand or build new pipelines in Canada and the United States to source new markets, many of which are in the regulatory application phase. There can be no assurance that such regulatory approvals will be secured on a timely basis or at all.

The recent ongoing decline in crude oil and natural gas prices has had and, if such prices persist, may continue to have an adverse effect on the Company's operations, financial condition, borrowing ability, levels of reserves and resources, the level of expenditures for the development of the Company's oil and natural gas reserves or resources and could result in further impairment test write-downs. Certain oil or natural gas wells have become uneconomic to produce as a result of low commodity prices and others may become uneconomic if commodity prices remain low, thereby impacting the Company's production volumes, or our desire to market our production in unsatisfactory market conditions. Furthermore, the Company is subject to the decisions of third party operators who have decided and may continue to decide to curtail production. The current low commodity price environment has resulted in reduced credit facilities available to the Company and should it persist, could require that a portion of the Company's debt be repaid.

From time to time the Company may enter into agreements to receive fixed prices on our oil and natural gas production to offset the risk of revenue losses if commodity prices decline, known as hedging, however, if commodity prices increase beyond the levels set in such agreements, the Company will not benefit from such increases and the Company may nevertheless be obligated to pay royalties on such higher prices, even though not received by us, after giving effect to such agreements. The Company could also be subject to margin requirements associated with certain hedging instruments.

Reserves

The Company's future reserves and production and, therefore, cash flows are highly dependent upon success in exploiting the Company's current reserves base and acquiring or discovering additional reserves. Without reserves additions through exploration, acquisition or development activities, Lightstream's reserves and production will decline over time. Exploring for, developing or acquiring reserves is capital intensive. To the extent cash from operations are insufficient to fund the Company's capital expenditures and external sources of capital become limited or unavailable, Lightstream's ability to make the necessary capital investments to maintain oil and natural gas reserves will be impaired. Costs to find and develop or acquire additional reserves also depend on success rates, which vary over time. Without reserve additions, our reserves will deplete and as a consequence, either production from, or the average reserve life of, our properties will decline. Either decline may result in a reduction in the value of the Common Shares.

As a result of our conservative capital investment in 2015 in response to low commodity prices and our 2014 asset disposition program, our average production declined to 31,392 boepd in 2015 from an average of 40,420 boepd in 2014. Assuming continued low commodity prices, we are projecting a continued moderate capital plan for first half 2016 with resulting average production of between 25,000 to 25,500 boepd for the same period.

Oil and Natural Gas Production and Ultimate Reserves Could Vary Significantly From Reported Reserves

The Company's reserve evaluations have been prepared in accordance with NI 51-101. There are numerous uncertainties inherent in estimating quantities of reserves and cash flows to be derived therefrom, including many factors that are beyond the control of the Company. The reserves information set forth in this Annual Information Form represents estimates only. The reserves from the Company's properties have been independently evaluated by Sproule. These evaluations include a number of assumptions relating to factors such as future prices of oil and natural gas, initial production rates, production decline rates, ultimate recovery of reserves, timing and amount of capital expenditures, marketability of production, operating costs and royalties and other government levies that may be imposed over the producing life of the reserves. These assumptions were based on price forecasts in use at the date the relevant evaluations were prepared and many of these assumptions are subject to change and are beyond the control of the Company. Actual reserves, production and cash flows derived therefrom will vary from these evaluations, and such variations could be material. These evaluations are based, in part, on the assumed success of exploitation activities intended to be undertaken in future years. The reserves and estimated cash flows to be derived therefrom contained in such evaluations will be reduced to the extent that such exploitation activities do not achieve the level of success assumed in the evaluations.

Under IFRS, impairment testing is performed at the cash generating unit level ("CGU"), with asset carrying values being compared to the recoverable amount which is the higher of the value-in-use and fair value less costs to sell. Value in use is defined as the amount equal to the present value of future cash flows expected to be derived from the asset. When the asset carrying value (including goodwill) is less than the recoverable amounts, an impairment loss is recorded. A decline in the proved and probable reserve values of the oil and natural gas properties could result in the carrying value of the assets exceeding the recoverable amount, resulting in an impairment loss. Impairment losses that were previously recognized may be reversed where circumstances change such that the impairment is reduced, provided however any impairment losses associated with goodwill are permanent and not reversible. The Company recorded a $905 million impairment expense in 2015, primarily as a result of reduced commodity price forecasts and change in discount rates.

Fluctuations in Foreign Currency Exchange Rates

Fluctuations in foreign currency exchange rates could adversely affect our business. The price that we receive for a majority of our oil and natural gas is based on United States dollar denominated benchmarks, and, therefore, the price that we receive in Canadian dollars is affected by the exchange rate between the two currencies. A material increase in the value of the Canadian dollar relative to the United States dollar may negatively impact net production revenue by decreasing the Canadian dollars received for a given United States dollar price, while also negatively impacting the future value of the Company's reserves as determined by independent evaluators. In addition, a significant portion of the Company's long term debt is denominated in US dollars and, while providing a hedge against the revenue stream, the fluctuation in the exchange rate may impact the amount of Canadian dollars required to settle these obligations. The significant decline in the Canadian/U.S. dollar exchange rate over the last 18 months has resulted in higher interest obligations on our U.S. dollar denominated debt. We could be subject to unfavourable price changes to the extent that we have engaged, or in the future engage, in risk management activities related to foreign exchange rates, through entry into forward foreign exchange contracts or otherwise.

Marketing of Oil and Natural Gas Production

Our business depends in part upon the availability, proximity and capacity of oil and gas gathering systems, pipelines and processing facilities to our assets. Canadian federal and provincial, as well as United States federal and state, regulation of oil and gas production, processing and transportation, tax and energy policies, general economic conditions, weather, pipeline disruptions, refinery capacity and changes in supply and demand could adversely affect our ability to produce and market oil and natural gas. If market factors change and inhibit the marketing of our production, overall production or realized prices may decline, which could result in materially lower revenues and cash flow.

New resource plays generally experience a sharp increase in the amount of production being produced in the area which could exceed the existing capacity of the various gathering, processing and pipeline infrastructure. For example, pipeline and facility constraints experienced by oil producers in the Cardium area of Alberta have become more pronounced as a result of increased drilling and development activities in these regions. If these constraints remain unresolved, the Company's ability to produce and transport our production in these regions may be impaired and could adversely impact the Company's production volumes or realized prices from these areas.

Oil and natural gas producers in North America, and particularly Canada, have and in the future may receive discounted prices for their production due to constraints on the ability to transport and sell such production to international markets. Also, limited natural gas processing and fractionation capacity may result in producers not realizing the full price for liquids associated with their natural gas production. A failure to resolve such constraints may result in shut-in production or continued reduced commodity prices received by oil and natural gas producers.

While the third party pipelines generally expand capacity to meet market needs, there can be differences in timing between the growth of production and the growth of pipeline capacity, and unfavourable economic conditions or financing terms may defer or prevent the completion of certain pipeline projects or gathering systems that are planned for such areas. There are also occasional operational reasons, including as a result of maintenance activities, for curtailed transportation capacity. Accordingly, there can be periods where transportation capacity is insufficient to accommodate all of the production from a given region, causing added expense and/or volume curtailments for all shippers. In such event, the Company may have to defer development of or shut in our wells awaiting a pipeline connection or capacity and/or sell our production at lower prices than it would otherwise realize or than the Company currently projects, which would adversely affect the Company's results of and funds flow from operations.

Environmental Regulation

Many aspects of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of federal, provincial and local laws and regulations. Environmental legislation provides for, among other things, restrictions and prohibitions on spills, releases or emissions of various substances produced in association with oil and natural gas operations. The legislation also requires that wells and facility sites be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. Compliance with such legislation can require significant expenditures and a breach of applicable environmental legislation may result in the imposition of fines and penalties, suspension or revocation of regulatory permits, third party liabilities or the requirement to remediate, which may be material. See *"Industry Conditions – Environmental Regulation"*.

We may also be subject to associated liabilities, resulting from lawsuits alleging property damage or personal injury brought by private litigants related to the operation of the Company's facilities or the land on which such facilities are located, regardless of whether we lease or own the facility, and regardless of whether such environmental conditions were created by the Company or by a prior owner or tenant, or by a third party or neighbouring facility whose operations may have affected the Company's facility or land. Such liabilities could have a material adverse effect on our business, financial position, operations, assets or future prospects.

We also face uncertainties related to future environmental laws and regulations affecting our business and operations. Existing environmental laws and regulations may be revised or interpreted more strictly, and new laws or regulations may be adopted or become applicable to the Company, which may result in increased compliance costs or additional operating restrictions, each of which could reduce our earnings and adversely affect our business, financial position, operations, assets or future prospects.

Compliance with environmental laws and regulations could materially increase our costs. We may incur substantial capital and operating costs to comply with increasingly complex laws covering the protection of the environment and human health and safety. In particular, we may be required to incur significant costs to comply with future federal GHG emissions reduction requirements or other GHG emissions regulations compliance costs, if enacted. See *"Climate Change"* below.

Although we record a provision in our consolidated financial statements relating to our estimated future abandonment and reclamation obligations, we cannot guarantee that we will be able to satisfy our actual future abandonment and reclamation obligations. Although the Company maintains insurance consistent with prudent industry practice, we are not fully insured against certain environmental risks, either because such insurance is not available or because of high premium costs. In particular, insurance against risks from environmental pollution occurring over time (as opposed to sudden and catastrophic damages) is not available on economically reasonable terms.

Climate Change

Our exploration and production facilities and other operations and activities emit GHGs and require us to comply with GHG emissions legislation at the federal and provincial levels. Climate change policy is evolving at regional, national and international levels, and political and economic events may significantly affect the scope and timing of climate change measures that are ultimately put in place. As a signatory to the UNFCCC and as a participant to the Paris Agreement (an agreement created by the UNFCCC), the Government of Canada announced in May 2015 a pledge to reduce GHG emissions from 2005 levels by 30% by 2030. In addition, the Government of Alberta also announced its Climate Leadership Plan in May 2015, which includes an initial Alberta economy-wide price on GHG emissions of $30/tonne, and a methane reduction strategy to address methane emissions in the oil and gas sector. As a result, it is expected that some of our significant facilities will be subject to proposed provincial and federal climate change initiatives to manage GHG emissions. The direct or indirect costs of compliance with these regulations may have a material adverse effect on our business, financial condition, results of operations and prospects. See "*Industry Conditions – Greenhouse Gases and Industrial Air Pollutants*".

Changes in Laws, Regulations or Government Policy

The oil and gas industry in general is subject to extensive government policies and regulations, which result in additional cost and risk for industry participants. Changes in tax and other laws may adversely affect the value of our Common Shares. Income tax laws, royalty rates, other laws or government incentive programs relating to the oil and gas industry may in the future be changed or interpreted in a manner that adversely affects the Company and our shareholders. Tax authorities having jurisdiction over the Company or the shareholders may disagree with the manner in which we calculate our income for tax purposes or could change their administrative practices to our detriment or the detriment of our shareholders.

Potential Risks Associated with Hydraulic Fracturing

Lightstream utilizes horizontal drilling, multi-stage hydraulic fracturing, specially formulated drilling fluids and other technologies in connection with our drilling and completion activities. There has been public concern over the hydraulic fracturing process. Most of these concerns have raised questions regarding the completion fluids used in the fracturing process, their effect on fresh water aquifers, the use of water in connection with completion operations and the ability of such water to be recycled and the potential for induced seismicity associated with fracturing.

Certain government and regulatory agencies in Canada have begun investigating the potential risks associated with the hydraulic fracturing process. The Canadian federal government and certain provincial governments are currently reviewing certain aspects of the scientific, regulatory and policy framework under which hydraulic fracturing operations are conducted. At present, most of these governments are primarily engaged in the collection, review and assessment of technical information regarding the hydraulic fracturing process and, with the exception of increased chemical disclosure requirements in certain of the jurisdictions in which the Company operates, have not provided specific details with respect to any significant actual, proposed or contemplated changes to the hydraulic fracturing regulatory construct. However, certain environmental and other groups have suggested that additional federal, provincial, territorial, state and municipal laws and regulations may be needed to more closely regulate the hydraulic fracturing process, and have made claims that hydraulic fracturing techniques are harmful to surface water and drinking water sources and may contribute to earthquake activity particularly where in proximity to pre-existing faults. Further, certain governments in jurisdictions where the Company does not currently operate have considered a temporary moratorium on hydraulic fracturing until further studies can be completed and some governments have adopted, and others have considered adopting, regulations that could impose more stringent permitting, disclosure and well construction requirements on hydraulic fracturing operations.

It is anticipated that federal and provincial regulatory frameworks to address concerns related to hydraulic fracturing will continue to emerge. While we are unable to predict the impact of any potential regulations upon our business, the implementation of new regulations with respect to water usage or hydraulic fracturing generally could increase the Company's costs of compliance, operating costs, the risk of litigation and environmental liability, or negatively impact the Company's prospects, any of which may have a material adverse effect on our business, financial condition and results of operations.

Abandonment and Reclamation Costs

Lightstream will be responsible for compliance with terms and conditions of environmental and regulatory approvals and all laws and regulations regarding abandonment and reclamation in respect of our properties, which abandonment and reclamation costs may be substantial. A breach of such legislation or regulations may result in the imposition of fines and penalties, including an order for cessation of operations at the site until satisfactory remedies are made.

Operating Costs and Production Levels

An increase in operating costs or a decline in our production level could have a material adverse effect on our results of operations and financial condition. Electricity, trucking, chemicals, supplies, reclamation and abandonment and labour costs are a few of the operating costs that are susceptible to material fluctuation. The level of production from our existing properties may decline at rates greater than anticipated due to unforeseen circumstances, many of which are beyond our control. A significant decline in our production could result in materially lower revenues and cash flow.

Seasonality

The level of activity in the Canadian oil and gas industry is influenced by seasonal weather patterns. Wet weather and spring thaw may make the ground unstable. Consequently, municipalities and provincial transportation departments enforce road bans that restrict the movement of rigs and other heavy equipment, thereby reducing activity levels. Also, certain oil and gas producing areas are located in areas that are inaccessible other than during the winter months because the ground surrounding the sites in these areas consists of swampy terrain. Reduced activity levels caused by weather related issues may cause us to shut-in producing wells and to delay the drilling and completion of wells and the construction of facilities which could reduce production levels and cash flows.

Strong Competition

The oil and natural gas industry is intensely competitive. Competition is particularly intense in the acquisition of prospective oil and natural gas properties and oil and gas reserves. Lightstream's competitive position depends on our geological, geophysical and engineering expertise, our financial resources, our ability to develop our properties and our ability to select, acquire and develop our reserves. Lightstream competes with a substantial number of other companies having larger technical staffs and greater financial and operational resources. Many such companies not only engage in the acquisition, exploration, development and production of oil and natural gas reserves, but also carry on refining operations and market refined products. Lightstream also competes with major and independent oil and natural gas companies and other industries supplying energy and fuel in the marketing and sale of oil and natural gas to transporters, distributors and end users, including industrial, commercial and individual consumers. Lightstream also competes with other oil and natural gas companies in attempting to secure drilling rigs and other equipment necessary for drilling and completion of wells. Such equipment may be in short supply from time to time. In addition, equipment and other materials necessary to construct production and transmission facilities may be in short supply from time to time. Finally, companies not previously investing in oil and natural gas may choose to acquire reserves to establish a firm supply or simply as an investment. Such companies also provide competition for Lightstream.

Reliance on Third Party Operators

The continuing production from a property, and to some extent the marketing of that production, is dependent upon the ability of the operators of the Company's properties. In 2015, approximately 12% of the Company's production was from properties operated by third parties. This results in significant reliance on third party operators in both the operation and development of such properties and control over capital expenditures relating thereto. The timing and amount of capital required to be spent by the Company may differ from the Company's expectations and planning, and may impact the ability and/or cost of the Company to finance such expenditures, as well as adversely affect other parts of the Company's business and operations. To the extent a third party operator fails to perform these duties properly, faces capital or liquidity constraints or becomes insolvent, the Company's results of operations will be negatively impacted.

Operating Hazards

Oil and natural gas exploration, development and production operations are subject to all the risks and hazards typically associated with such operations, including hazards such as fire, explosion, blowouts, and oil spills, each of which could result in substantial damage to oil and natural gas wells, production facilities, other property and the environment or in personal injury. In accordance with industry practice, the Company is not fully insured against all of these risks, nor are all such risks insurable. Although Lightstream maintains liability insurance in an amount that it considers adequate and consistent with industry practice, the nature of these risks is such that liabilities could exceed policy limits, in which event Lightstream could incur significant costs that could have a materially adverse effect upon our financial condition. Oil and natural gas production operations are also subject to all the risks typically associated with such operations, including premature decline of reservoirs and the invasion of water into producing formations.

Availability of Drilling Equipment and Access

Oil and natural gas exploration and development activities are dependent on the availability of drilling and related equipment (typically procured from third parties) in the particular areas where such activities are conducted. Demand for such limited equipment or access restrictions may affect the availability of such equipment and may delay exploration and development activities.

Key Personnel

The Company's success depends, to a significant extent, upon management and key employees. The loss of key employees could have a negative effect on our business, financial condition, results of operations and prospects. The Company faces significant competition for skilled personnel. There is no assurance that the Company will successfully attract and retain personnel required to successfully execute our business strategy.

Permits, Licenses and Leases

Significant parts of the Company's operations require permits, licenses and leases from various governmental authorities and landowners. There can be no assurance that the Company will be able to obtain all necessary permits, licenses and leases that may be required to carry out exploration and development at our projects. If the present permits, licenses and leases are terminated or withdrawn, such event could have an adversely negative effect of the Company's operations.

Title to Properties

Although title reviews are done according to industry standards prior to the purchase of most oil and natural gas producing properties or the commencement of drilling wells, such reviews do not guarantee or certify that an unforeseen defect in the chain of title will not arise to defeat the claim of Lightstream which could result in a reduction of the revenue received by Lightstream.

Potential Liability Regarding Tax Reassessments

Lightstream may be subject to tax reassessments in the future as a result of audits conducted by the Canada Revenue Agency. While the Company believes there would be no material impact from any potential reassessment, if such a reassessment were to be successful it could result in cash taxes, interest and penalties to be paid as well as reduction in tax pools available to the Company to reduce future income taxes and such amounts could be material.

Conflicts of Interest

Certain of the officers and directors of the Company may have associations with other oil and gas companies or with other industry participants with whom the Company conducts business and situations may arise where the directors and officers will be in direct competition with the Company. Conflicts, if any, will be subject to the procedures and remedies under the ABCA.

Please also see the information under the heading *"Risks and Uncertainties"* in management's discussion and analysis of the Company for the year ended December 31, 2015, which has been filed via SEDAR on March 3, 2016 under our profile at www.sedar.com.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

Except as disclosed herein, no director, executive officer, or person or company that is the direct or beneficial owner of, or who exercises control or direction over, more than 10 percent of the common shares and no associate or affiliate of any of the foregoing has, or has had, any material interest in any transaction prior to the date hereof or any proposed transaction that has materially affected or will materially affect the Company.

LEGAL PROCEEDINGS

There are no legal proceedings involving claims for damages in an amount exceeding 10% of Lightstream's current assets to which Lightstream is or was a party or in respect of which any of our properties are or were subject during the year ended December 31, 2015, nor are there any such proceedings known to Lightstream to be contemplated.

MATERIAL CONTRACTS

Set out below are the agreements that may be considered material to us.

1. Secured Note Indenture. See *"Capital Structure – Secured Notes"*.

2. Unsecured Note Indenture. See *"Capital Structure – Unsecured Notes"*.

3. Shareholder Rights Plan. See *"Capital Structure –Shareholder Rights Plan"*.

TRANSFER AGENT AND REGISTRAR

The Company's transfer agent and registrar for the Common Shares is Computershare, located at 600, 530 – 8th Avenue SW, Calgary, Alberta T2P 3S8.

INTERESTS OF EXPERTS

Deloitte LLP, Chartered Professional Accountants, Chartered Accountants, is the Company's auditor and as such have prepared an opinion with respect to the Company's consolidated financial statements as at and for the fiscal year ended December 31, 2015. Deloitte LLP is independent within the meaning of the Rules of Professional Conduct as outlined by the Institute of Chartered Accountants of Alberta.

Information relating to reserves in this Annual Information Form was calculated by Sproule as Lightstream's independent qualified reserves evaluator. The principals of Sproule, individually or as a group, neither own nor expect to receive any of Lightstream's securities, directly or indirectly.

ADDITIONAL INFORMATION

Additional information relating to the Company may be found on SEDAR at www.sedar.com.

Additional information, including information as to directors' and officers' remuneration and indebtedness, principal holders of the Company's securities and securities authorized for issuance under equity compensation plans, if applicable, is available in the management proxy circular of the Company for the annual meeting of the shareholders of the Company held on May 14, 2015, and is available under our SEDAR profile at www.sedar.com or at www.lightstreamresources.com. Additional financial information is provided in our consolidated financial statements and management's discussion and analysis for the year ended December 31, 2015 which are available under our SEDAR profile at www.sedar.com or at www.lightstreamresources.com.

APPENDIX A

FORM 51-101F3
REPORT OF MANAGEMENT AND DIRECTORS ON OIL AND GAS DISCLOSURE

Management of Lightstream Resources Ltd. (the "**Company**") is responsible for the preparation and disclosure of information with respect to the Company's oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data.

Independent qualified reserves evaluators have evaluated the Company's reserves data. The report of the independent qualified reserves evaluators will be filed with securities regulatory authorities concurrently with this report.

The Reserves Committee of the Board of Directors of the Company has:

(a) reviewed the Company's procedures for providing information to the independent qualified reserves evaluators;
(b) met with the independent qualified reserves evaluators to determine whether any restrictions affected the ability of the independent qualified reserves evaluators to report without reservation; and
(c) reviewed the reserves data with management and the independent qualified reserves evaluators.

The Reserves Committee of the Board of Directors has reviewed the Company's procedures for assembling and reporting other information associated with oil and gas activities and has reviewed that information with management. The Board of Directors has, on the recommendation of the Reserves Committee, approved:

(a) the content and filing with securities regulatory authorities of Form 51-101F1 containing reserves data and other oil and gas information;
(b) the filing of Form 51-101F2 which is the report of the independent qualified reserves evaluators on the reserves data, and
(c) the content and filing of this report.

Because the reserves data are based on judgments regarding future events, actual results will vary and the variations may be material.

(signed) *"John D. Wright"*
John D. Wright
President, Chief Executive Officer, Director
and Member of the Reserves Committee

(signed) "W. Brett Wilson"
W. Brett Wilson
Director and Chairman of the Reserves Committee

(signed) *"Peter D. Scott"*
Peter D. Scott
Senior Vice President and Chief Financial Officer

(signed) "Corey C. Ruttan"
Corey C. Ruttan
Director and Member of the Reserves Committee

Dated: March 30, 2016

APPENDIX B

FORM 51-101F2
REPORT ON RESERVES DATA BY
INDEPENDENT QUALIFIED RESERVES EVALUATOR OR AUDITOR

To the Board of Directors of Lightstream Resources Ltd. (the "**Company**"):

1. We have evaluated the Company's reserves data as at December 31, 2015. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2015, estimated using forecast prices and costs.

2. The reserves data are the responsibility of the Company's management. Our responsibility is to express an opinion on the reserves data based on our evaluation.

3. We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook as amended from time to time (the "**COGE Handbook**") maintained by the Society of Petroleum Evaluation Engineers (Calgary Chapter).

4. Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the reserves data are free of material misstatement. An evaluation also includes assessing whether the reserves data are in accordance with principles and definitions presented in the COGE Handbook.

5. The following table shows the net present value of future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated for the year ended December 31, 2015, and identifies the respective portions thereof that we have audited, evaluated and reviewed and reported on to the Company's management and Board of Directors:

Independent Qualified Reserves Evaluator	Description and Preparation Date of Evaluation Report	Location of Reserves (Country)	Net Present Value of Future Net Revenue Before Income Taxes (10% Discount Rate)			
			Audited (M$)	Evaluated (M$)	Reviewed (M$)	Total (M$)
Sproule Associates Limited	Evaluation of the P&NG Reserves of Lightstream Resources Ltd., as of December 31, 2015, prepared October 2015 to February 2016	Canada				
Total			Nil	2,183,761	Nil	2,183,761

6. In our opinion, the reserves data respectively evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook, consistently applied. We express no opinion on the reserves data that we reviewed but did not audit or evaluate.

7. We have no responsibility to update our report referred to in paragraph 5 for events and circumstances occurring after the effective date of our report.

8. Because the reserves data are based on judgements regarding future events, actual results will vary and the variations may be material.

Executed as to our report referred to above:

Sproule Associates Limited
Calgary, Alberta, Canada
February 9, 2016

(signed) "*Vincent Hui*"
Vincent Hui, P.Eng.
Project Leader,
Petroleum Engineer and Partner

(signed) "*Steven J. Golko*"
Steven J. Golko, P.Eng.
Vice-President, Field Development & Capital Strategies and Partner

(signed) "*Richard A. Brekke*"
Richard A. Brekke, P.Eng.
Manager, Engineering and Partner

(signed) "*Rodney E. Fradette*"
Rodney E. Fradette, P.Eng.
Senior Petroleum Engineering and Partner

(signed) "*Stephanie Brunt*"
Stephanie Brunt, P.Eng.
Petroleum Engineer and Associate

(signed) "*Alec Kovaltchouk*"
Alec Kovaltchouk, P.Geo.
Vice-President, Geoscience and Partner

(signed) "*Cameron P. Six*"
Cameron P. Six, P.Eng.
Vice-President Engineering, Chief Engineer and Director

APPENDIX C

FORM 52-110F1
AUDIT COMMITTEE INFORMATION REQUIRED IN AN AIF

1. The Audit Committee's Charter

See Appendix "D" attached to this Annual Information Form for the text of Lightstream's Audit Committee charter.

2. Composition of the Audit Committee

Ian S. Brown – independent and financially literate.

Martin Hislop – independent and financially literate.

Kenneth R. McKinnon – independent and financially literate.

Corey C. Ruttan – independent and financially literate.

3. Relevant Education and Experience

Ian S. Brown: Mr. Brown has been a member of the Institute of Chartered Accountants since 1983. Mr. Brown was a Senior Managing Director at Raymond James Ltd. (formerly Goepel McDermid Inc.) from 1995 until December 2005, and was Executive Vice President at the Alberta Stock Exchange from 1986 to 1995. Mr. Brown is also Director of Bonavista Energy Trust and Cathedral Energy Services Ltd. Mr. Brown obtained his Bachelor of Arts from McMaster University in 1979 and his Bachelor of Commerce (Accounting) from the University of Windsor in 1980. Mr. Brown is a Chartered Accountant with over 25 years' experience in the financial markets. He has gained significant experience and expertise in analyzing financial statements and he has an understanding of internal controls and procedures for financial reporting. He has gained an understanding of Audit Committee functions through his Board and committee experience with other public corporations.

Martin Hislop: Mr. Hislop is a retired businessman with more than 40 years' experience in all aspects of financing and managing private and public oil and gas companies, partnerships and trusts. Mr. Hislop is also a director of Toscana Energy Income Corporation and Forent Energy Ltd. Mr. Hislop is a Chartered Accountant and former Chief Executive Officer of APF Energy Trust. Prior to founding the predecessor of APF Energy Trust in September 1994, Mr. Hislop was the President and CEO of Lakewood Energy Inc., a TSX-listed oil and gas company which was created as a result of the combination of 10 limited partnerships.

Kenneth R. McKinnon: Mr. McKinnon obtained his Bachelor of Commerce from the University of Calgary (Accounting) in 1980 and obtained his Bachelor of Laws from Queens University in 1983. Mr. McKinnon was the Vice President, Finance and Chief Financial Officer of Petrobank Energy and Resources Ltd. from November 1997 to March 2000 and has been a member of the Audit Committee on several other public companies. Over time he has gained experience in analyzing financial statements and he has an understanding of internal controls and procedures for financial reporting and has experience supervising persons engaged in the preparation, analysis and evaluation of financial statements. In 2006, he earned the ICD.D designation of the Institute of Corporate Directors, as a certified corporate director.

Corey C. Ruttan: Mr. Ruttan obtained his Bachelor of Commerce degree majoring in Accounting from the University of Calgary in 1994 and obtained his Chartered Accountant designation in 1997. Mr. Ruttan has over 25 years' of experience in the area of finance in public oil and gas companies. He is currently the President and Chief Executive Officer and a director of Alvopetro Energy Ltd. Mr. Ruttan began his career at KPMG LLP in May 1997 and starting working in the finance group of oil and gas companies in June 1999. Since then, he has held increasingly senior roles, including Executive Vice President and Chief Financial Officer of Lightstream Resources Ltd. (formerly PetroBakken Energy Ltd.) (October 2000 to May 2010) and Senior Vice President and Chief Operating Officer of Petrobank Energy and Resources Ltd. (March 2000 to May 2010) and of Petrominerales Ltd. (May 2006 to November 2013).

4. Reliance on Certain Exemptions

N/A

5. Reliance on the Exemption in Subsection 3.3(2) or Section 3.6

N/A

6. Reliance on Section 3.8

N/A

7. Audit Committee Oversight

N/A

8. Pre-Approval Policies and Procedures

The Audit Committee requires the Company to obtain Audit Committee approval for any non-audit services exceeding immaterial amounts.

9. External Auditor Service Fees (By Category)

Year Ended	Audit Fees	Audit Related Fees[1]	Tax Fees[2]	All Other Fees[3]
2014	$250,000	$57,000	$20,560	$5,000
2015	$230,000	$52,500	$30,287	$5,000

Notes:

1. Audit related fees relate to quarterly reviews, the issuance of securities for Lightstream, and IFRS related procedures.
2. Tax fees relate to US tax compliance, assistance with respect to tax audits, and general tax advisory services.
3. Other fees relate to services provided in connection with the issuance of the Unsecured Notes.

APPENDIX D

AUDIT COMMITTEE OF THE BOARD OF DIRECTORS MANDATE AND TERMS OF REFERENCE

I. PURPOSE

The primary function of the Audit Committee is to assist the Board of Directors (the "**Board of Directors**" or "Board") of Lightstream Resources Ltd. ("**Lightstream**" or the "**Corporation**") in fulfilling its responsibilities by reviewing: the financial reports and other financial information provided by Lightstream to any regulatory body or the public; the Corporation's systems of internal controls regarding preparation of those financial statements and related disclosures that management and the Board have established; and the Corporation's auditing, accounting and financial reporting processes generally. Consistent with this function, the Audit Committee should encourage continuous improvement of, and should foster adherence to, the Corporation's policies, procedures and practices at all levels. The Audit Committee's primary objectives are:

A. To assist directors in meeting their responsibilities in respect of the preparation and disclosure of the financial statements of the Corporation and related matters;

B. To provide for open communication between directors and external auditors;

C. To enhance the external auditor's independence;

D. To increase the credibility and objectivity of financial reports; and

E. To strengthen the role of the outside directors by facilitating in depth discussions between directors on the Audit Committee, management and external auditors.

II. COMPOSITION

1. The Audit Committee shall be comprised of three or more directors as determined by the Board of Directors, none of whom are members of management of Lightstream and all of whom are "unrelated directors" (as such term is used in the Report of the Toronto Stock Exchange on Corporate Governance in Canada) and "independent" (as such term is used in Multilateral Instrument 52-110 — Audit Committees ("**MI 52-110**") unless the Board shall have determined that the exemption contained in Section 3.6 of MI 52 110 is available and has determined to rely thereon.

2. All of the members of the Audit Committee shall be "financially literate" (as defined in MI 52-110) unless the Board shall determine that an exemption under MI 52-110 from such requirement in respect of any particular member is available and has determined to rely thereon in accordance with the provisions of MI 52-110.

3. The members of the Audit Committee shall be elected by the Board of Directors at the annual organizational meeting of the Board of Directors and remain as members of the Audit Committee until their successors shall be duly elected and qualified.

4. Unless a Chair is elected by the full Board of Directors, the members of the Audit Committee may designate a Chair by majority vote of the full Audit Committee membership.

III. MEETINGS

1. The Audit Committee shall meet at least four times annually, or more frequently as circumstances dictate. As part of its mandate to foster open communication, the Audit Committee should meet at least annually with management and the external auditors in separate executive sessions to discuss any matters that the Audit

Committee or each of these groups believe should be discussed privately. The Audit Committee or at least its Chair should meet with the external auditors and management quarterly to review the Corporation's financials consistent with Section IV.2 below. The Chief Financial Officer may, at the discretion of the Audit Committee, be present at meetings of the Audit Committee and may be excused from all or part of any such meetings by the Chairman.

2. Minutes of all meetings of the Audit Committee shall be taken and the Audit Committee shall report the results of its meetings and reviews undertaken and any associated recommendations to the Board of Directors.

3. A quorum for meetings of the Audit Committee shall be a majority of its members, and the rules for calling, holding, conducting and adjourning meetings of the Audit Committee shall be the same as those governing the Board.

IV. RESPONSIBILITIES AND DUTIES

To fulfill its responsibilities and duties, the Audit Committee shall:

Documents/Reports Review

1. Review and update this Charter, as conditions dictate.

2. Review the financial statements, prospectuses, management's discussion and analysis, annual information forms and all public disclosure containing audited or unaudited financial information (including, without limitation, annual and interim press releases and any other press releases disclosing earnings or financial results) before release and prior to Board approval where required.

3. Review the reports to management prepared by the external auditors and management's responses.

4. Review of significant auditor findings during the year, including the status of previous audit recommendations.

5. Be satisfied with and periodically assess the adequacy of procedures for the review of corporate disclosure that is derived or extracted from the financial statements.

6. It is the responsibility of the Audit Committee to review, on behalf of the Board, the Corporation's internal control systems in order satisfy the Audit Committee that the internal control systems are sufficient to reasonably ensure that:

   (a) controllable, material business risks are identified, monitored and mitigated where it is determined cost effective to do so;

   (b) internal controls over financial reporting are sufficient to meet the requirements under Multilateral Instrument 52-109 of the Canadian Securities Administrators,

   (c) legal, ethical and regulatory requirements are complied with; and

   (d) major issues as to the adequacy of the Corporation's internal controls and any special audit stops adopted in light of material control deficiencies are reviewed with the Audit Committee by the Chief Financial Officer of the Corporation.

External Auditors

7. Be directly responsible for overseeing the work of the external auditors, including the resolution of disagreements between management and the external auditors regarding financial reporting.

8. Recommend to the Board the external auditors to be nominated for appointment by the shareholders.

9. Recommend to the Board the terms of engagement of the external auditor, including their compensation and a confirmation that the external auditors shall report directly to the Audit Committee.

10. On an annual basis, review and discuss with the auditors all significant relationships the auditors have with the Corporation to determine the auditors' independence.

11. Review the performance of the external auditors and approve any proposed discharge of the external auditors when circumstances warrant.

12. When there is to be a change in auditors, review the issues related to the change and the information to be included in the required notice to securities regulators of such change.

13. Periodically consult with the external auditors, without the presence of management, about internal controls and the fullness and accuracy of the organization's financial statements.

14. Consider, in consultation with the external auditor, the audit scope and plan of the external auditor.

15. Pre-approve the completion of any non-audit services by the external auditors and determine which non-audit services the external auditor is prohibited from providing and the Audit Committee may delegate to one or more independent members of the Audit Committee the authority to pre approve non audit services, provided that such member(s) reports to the Audit Committee at the next scheduled meeting such pre-approval and the member(s) complies with such other procedures as may be established by the Audit Committee from time to time.

Financial Reporting Processes

16. In consultation with the external auditors and management, review the integrity of the organization's financial reporting processes, both internal and external.

17. Consider judgments concerning the appropriateness of the Corporation's accounting policies.

18. Consider and approve, if appropriate, major changes to the Corporation's auditing and accounting principles and practices as suggested by the external auditors or management.

19. Review risk management policies and procedures of the Corporation (i.e., hedging, litigation and insurance).

20. Establish a procedure for:

    (a) the receipt, retention and handling of complaints received by the Corporation regarding accounting, internal accounting controls or auditing matters; and

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

21. Approve management recommendations of appointment of individuals to senior financial reporting positions within the Corporation.

Process Improvement

22. Establish regular and separate systems of reporting to the Audit Committee by management and the external auditors regarding any significant judgments made in management's preparation of the financial statements and the view of each group as to appropriateness of such judgments.

23. Following completion of the annual audit, review separately with management and the external auditors any significant difficulties encountered during the course of the audit, including any restrictions on the scope of work or access to required information.

24. Review with external auditors their assessment of internal controls, their written reports containing recommendations for improvement, and management's response and follow-up to any identified weaknesses. The Committee shall also review annually with the external auditors their plan for their audit and, upon completion of the audit, their reports upon the financial statements.

Ethical and Legal Compliance

25. Ensure that management has the proper review system in place to ensure that the Corporation's financial statements, reports and other financial information disseminated to regulatory organizations and the public satisfy legal requirements.

26. On at least an annual basis, review with the Corporation's counsel and/or management, any legal matters, compliance with applicable laws and regulations, or inquiries received from regulators or government agencies that could have a significant impact on the organization's financial statements.

27. Conduct and authorize investigations into any matters within the Audit Committee's scope of responsibilities. The Audit Committee shall be empowered to retain, and to set and pay compensation for any independent counsel and other professionals to assist in the conduct of any investigation.

28. Perform any other activities consistent with this Charter, the Corporation's by-laws and governing law, as the Audit Committee or the Board of Directors deems necessary or appropriate.

LIGHTSTREAM
RESOURCES

ANNUAL INFORMATION FORM
FOR THE YEAR ENDED DECEMBER 31, 2014

March 31, 2015

EXHIBIT 2 DATE Oct 3/16
WITNESS P. D. Scott
HEATHER BOWIE
COURT REPORTER

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DEFINITIONS

In this Annual Information Form, the capitalized terms set forth below have the following meanings:

ABCA means the *Business Corporations Act* (Alberta), R.S.A. 2000, c. B-9, as amended, together with all regulations promulgated thereunder;

Board means the Board of Directors of Lightstream;

COGE Handbook means the Canadian Oil and Gas Evaluation Handbook as amended from time to time maintained by the Society of Petroleum Evaluation Engineers (Calgary Chapter);

Common Shares means the common shares of the Company;

Company, Corporation, Lightstream, we or **us** means Lightstream Resources Ltd. and, where applicable, our subsidiaries and affiliates, including our interests in joint ventures and partnerships;

Convertible Notes means the 3.125% convertible notes of the Company that mature January 2016;

CSA 51-324 means Staff Notice 51-324 – *Glossary to NI 51-101 Standards of Disclosure for Oil and Gas Activities* of the Canadian Securities Administrators;

GAAP means Canadian generally accepted accounting principles, which incorporates IFRS for the year beginning January 1, 2011;

Gross means: (a) in relation to the Company's interest in production and reserves, our working interest (operating and non-operating) share before deduction of royalties and without including any royalty interest of the Company; (b) in relation to wells, the total number of wells in which the Company has an interest; and (c) in relation to properties, the total area of properties in which the Company has an interest;

IFRS means International Financial Reporting Standards;

NCIB means normal course issuer bid;

Net means: (a) in relation to the Company's interest in production and reserves, our working interest (operating and non-operating) share after deduction of royalties obligations, plus the Company's royalty interest in production or reserves; (b) in relation to wells, the number of wells obtained by aggregating the Company's working interest in each of our gross wells; and (c) in relation to the Company's interest in a property, the total area in which the Company has an interest multiplied by the working interest owned by the Company;

NI 51-101 means National Instrument 51-101 - *Standards of Disclosure for Oil and Gas Activities* of the Canadian Securities Administrators;

New Petrobank means the company incorporated under the ABCA that is currently called Touchstone Exploration Inc.;

Note Indenture means the note indenture dated January 30, 2012 between the Company, our material subsidiaries, U.S. National Bank Association and Computershare Trust Company of Canada governing the Senior Notes;

Old Petrobank means the company incorporated under the ABCA and formerly called Petrobank Energy and Resources Ltd. that amalgamated with the Company on December 31, 2012;

Petrobank Reorganization means the series of transactions completed on December 31, 2012 under a plan of arrangement under the ABCA between the Company, Old Petrobank and New Petrobank pursuant to which, among other things, (a) Old Petrobank transferred its existing heavy oil business to New Petrobank and distributed the shares of New Petrobank to its shareholders, and (b) the Company and Old Petrobank amalgamated, with the amalgamated company continuing under the name "PetroBakken Energy Ltd.", (c) each shareholder of Old Petrobank received 1.1051 Common Shares for each Old Petrobank share held immediately prior to the reorganization, and (d) each shareholder of the Company received one Common Share for each Class A Share of the Company held immediately prior to the reorganization;

Senior Notes means the senior unsecured notes of the Company issued pursuant to the Note Indenture;

Shareholder Rights Plan means the shareholder rights plan of the Company dated November 19, 2012 and effective January 1, 2013 as described under *"Capital Structure –Shareholder Rights Plan"*;

Sproule means Sproule Associates Limited, independent petroleum engineers, of Calgary, Alberta, Canada;

Sproule Report means the independent engineering evaluation of the Company's crude oil and natural gas reserves in Canada prepared by Sproule, dated February 25, 2015, with an effective date of December 31, 2014;

subsidiary has the meaning given to such term in the *Securities Act* (Alberta); and

TSX means the Toronto Stock Exchange.

ABBREVIATIONS

Oil and Natural Gas Liquids		**Natural Gas**	
bbl	barrel	**Mcf**	Thousand cubic feet
bbl/d	Barrels per day	**Mcf/d**	Thousand cubic feet per day
Mbbls	Thousand barrels	**MMcf**	Million cubic feet
BOE or boe	Barrels of oil equivalent	**MMcf/d**	Million cubic feet per day
boe/d or boepd	Barrels of oil equivalent per day	**MMBtu**	Million Metric British Thermal Units
Mboe	1,000 barrels of oil equivalent	**m^3**	Cubic metre
NGL	Natural gas liquids	**10^3m^3**	Thousands of cubic metres
		GJ	gigajoule

Other	
AECO	a natural gas storage facility located at Suffield, Alberta
API	American Petroleum Institute
°API	an indication of the specific gravity of crude oil measured on the API gravity scale. Liquid petroleum with a specified gravity of 28° API or higher is generally referred to as light crude oil
WTI	West Texas Intermediate, the reference price paid in U.S. dollars at Cushing, Oklahoma for crude oil of standard grade
M$ or $000s	Thousands of Canadian dollars
US$	United States dollars

CONVENTIONS

Certain other terms used in this Annual Information Form but not otherwise defined herein shall have the same meanings as defined in NI 51-101 and CSA 51-324 unless the context otherwise requires.

We have adopted the standard of six Mcf to one bbl when converting natural gas to oil. **Disclosure provided herein in respect of boes may be misleading, particularly if used in isolation. A boe conversion ratio of six Mcf to**

one bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent an economic value at the wellhead. Given that the value ratio based on the current price of crude oil as compared to natural gas is significantly different from the energy equivalency of 6:1, utilizing a conversion on a 6:1 basis may be misleading as an indication of value.

In this Annual Information Form, references to "dollars" and "$" are to the currency of Canada, unless otherwise indicated.

Unless the context otherwise requires, reference in this Annual Information Form to "Lightstream" or the "Company" are to Lightstream Resources Ltd., formerly PetroBakken Energy Ltd., and our subsidiaries and affiliates including interests in joint ventures and partnerships.

Unless otherwise noted, the Company's average daily production volumes disclosed herein are based on the Company's working interest production before deduction of royalties paid to others and including royalty volumes received. **Estimated values of future net revenue disclosed in this Annual Information Form do not necessarily represent fair market values.**

NOTICE TO READER

Special Note Regarding Forward-Looking Statements

Certain statements contained in this Annual Information Form constitute forward-looking statements. The Company believes the expectations reflected in those forward-looking statements are reasonable, but no assurance can be given that these expectations will prove to be correct. Accordingly, any such forward-looking statements are qualified in their entirety by reference to, and are accompanied by, the factors discussed throughout this Annual Information Form. Such forward-looking statements included in this Annual Information Form should not be unduly relied upon.

In particular, this Annual Information Form may contain forward-looking statements pertaining to the following:

- projections of market prices, foreign currency exchange rates and costs;
- supply and demand for oil and natural gas;
- planned capital expenditure programs and anticipated results thereof;
- planned drilling and development activity and anticipated results thereof;
- free cash flow and debt levels;
- ability of the Company to complete asset dispositions at favourable metrics;
- the characteristics of the Company's oil and natural gas properties and anticipated future performance;
- oil and natural gas production levels;
- the size of the oil and natural gas reserves;
- the Company's plans for the development of our proved undeveloped reserves and probable undeveloped reserves;
- the anticipated means of funding future development costs;
- planned enhanced recovery programs and anticipated results thereof;
- expectations regarding the ability of the Company to continually add to reserves through acquisitions and development;
- treatment under governmental regulatory regimes and tax laws;
- anticipated costs of compliance with environmental laws and regulations;
- anticipated future abandonment and reclamation costs; and
- the Company's dividend policy and future dividend payments.

In addition, statements relating to "reserves" or "resources" are deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions that the resources and reserves described can be profitably produced in the future.

With respect to forward-looking statements contained in this Annual Information Form, the Company has made assumptions regarding:

- oil and natural gas production levels;
- commodity prices;
- general economic and financial market conditions and availability of capital;
- timing and amount of capital expenditures;
- access to infrastructure for processing and marketing our production;
- availability of labour and drilling equipment and access to drilling locations;
- government regulation in the areas of taxation, royalty rates and environmental protection;
- the performance of existing wells and new wells; and
- our ability to obtain necessary regulatory approvals.

The Company believes the expectations and assumptions reflected in the forward-looking statements set forth herein are reasonable, but no assurance can be given that these expectations or assumptions will prove to be correct. Accordingly, any such forward-looking statements should not be unduly relied upon.

Actual results could differ materially from those anticipated in the forward-looking statements set forth herein as a result of the risk factors set forth below and elsewhere in this Annual Information Form:

- volatility in market prices for oil, NGLs and natural gas;
- fluctuations in foreign currency exchange rates;
- financial resources of the Company;
- global economic conditions and the Company's ability to access equity and debt markets;
- risks inherent in oil and natural gas operations (including operational risks in development, exploration and production, delays or changes in plans with respect to exploration or development projects or capital expenditures, the uncertainty of estimates and projections relating to production, costs and expenses, reliance on industry partners, availability of equipment and personnel, availability of third party infrastructure, and uncertainty surrounding timing for drilling and completion activities resulting from weather or access restrictions);
- uncertainties associated with estimating oil and natural gas reserves;
- unfavourable market for asset dispositions;
- competition for, among other things, capital and acquisitions of reserves and undeveloped lands;
- geological, technical, drilling and processing problems;
- the ability to economically test, develop and utilize new technologies;
- changes in legislation, including changes in environmental or tax laws, royalty rates or government incentive programs relating to the oil and gas industry; and
- the other factors discussed under the heading "*Risk Factors*".

Readers are cautioned that the foregoing lists of factors are not exhaustive. The forward-looking statements contained in this Annual Information Form are expressly qualified by this cautionary statement. Further, any forward-looking statement is made only as of a certain date, and the Company undertakes no obligation to update any forward-looking statement or statements to reflect events or circumstances after the date on which such statement is made or to reflect the occurrence of unanticipated events, except as may be required by applicable securities laws. New factors emerge from time to time, and it is not possible for management of the Company to predict all of these factors and to assess in advance the impact of each such factor on the Company's business or the extent to which any factor, or combination of factors, may cause actual results to differ materially from those contained in any forward-looking statement.

Non-GAAP Measures

This Annual Information Form contains financial terms that are not considered measures under GAAP, such as netback or operating netback. These measures are commonly utilized in the oil and gas industry and are considered informative for management and stakeholders. Specifically, profitability relative to commodity prices per unit of production is demonstrated by an operating netback. Operating netback reflects revenues less royalties, transportation costs, and production expenses divided by production for the period. Operating netbacks do not have standardized meanings and therefore may not be comparable to those reported by other companies, nor should they be viewed as an alternative to cash flow from operations or other measures of financial performance calculated in accordance with GAAP.

CORPORATE STRUCTURE

Incorporation and Material Reorganizations

The Company was incorporated as PetroBakken Energy Ltd. under the ABCA on July 30, 2009.

The Company completed the Petrobank Reorganization on December 31, 2012, pursuant to which, among other things, it amalgamated with Old Petrobank under the ABCA with the resulting company continuing under the name PetroBakken Energy Ltd.

The Company amended our articles to change our name to Lightstream Resources Ltd. on May 22, 2013.

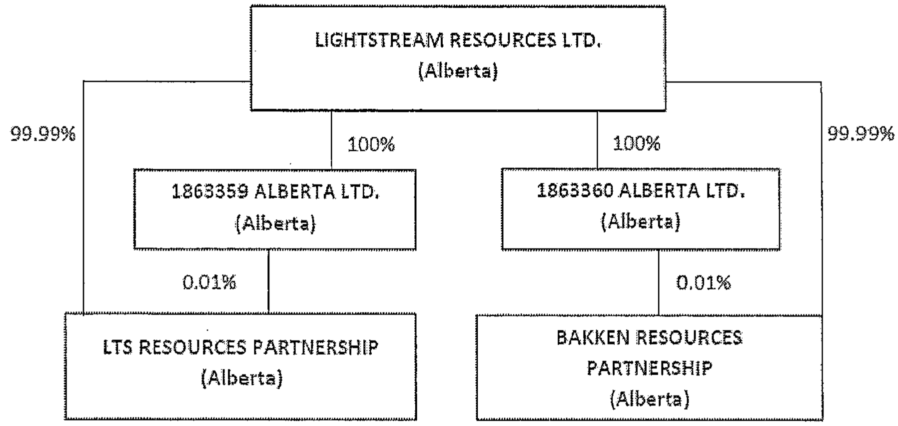
On January 2, 2015, the Company completed an internal reorganization whereby Lightstream Resources Partnership, a general partnership owned by the Company (99.9%) and Lightstream Capital Ltd. (0.1%), a wholly-owned subsidiary of the Company transferred (i) all of our assets located in Alberta and British Columbia to LTS Resources Partnership, a newly formed general partnership owned by the Company (99.99%) and 1863359 Alberta Ltd. (0.01%), a newly incorporated wholly-owned subsidiary of the Company, and (ii) all of our assets located in Saskatchewan to Bakken Resources Partnership, a newly formed general partnership owned by the Company (99.99%) and 1863360 Alberta Ltd. (0.01%), a newly incorporated wholly-owned subsidiary of the Company. Lightstream Resources Partnership and Lightstream Capital Ltd. were subsequently dissolved on January 2, 2015. The Company is the managing partner of both LTS Resources Partnership and Bakken Resources Partnership. See a diagram of our current structure under *"Our Organizational Structure"*.

The registered office of the Company is located at Suite 3300, 421 – 7th Avenue S.W., Calgary, Alberta T2P 4K9, and our head office is located at Suite 2800, 525 – 8th Avenue S.W., Calgary, Alberta T2P 1G1.

Our Organizational Structure

LTS Resources Partnership owns all of our oil and natural gas properties located in Alberta and British Columbia and is owned 100 per cent directly or indirectly by Lightstream Resources Ltd. Bakken Resources Partnership owns all of our oil and natural gas properties in Saskatchewan and is owned 100 per cent directly or indirectly by Lightstream Resources Ltd. Lightstream Resources Ltd. is the managing partner of LTS Resources Partnership and Bakken Resources Partnership. LTS Resources Partnership and Bakken Resources Partnership are partnerships formed under the laws of Alberta.

The following diagram sets forth our organizational structure as of the date hereof.



THREE-YEAR HISTORY OF THE BUSINESS

Year Ended December 31, 2012

On January 30, 2012, the Company closed a private placement of Senior Notes having a principal amount of US$900 million. The Senior Notes bear interest at a rate of 8.625% per annum and mature February 1, 2020. See also *"Credit Ratings"*.

On January 31, 2012, in conjunction with the Senior Notes issuance, the Company completed the repurchase of US$450 million of principal amount of Convertible Notes at a price of US$99,000 per US$100,000 of principal amount, leaving US$300 million outstanding.

On January 31, 2012, also in conjunction with the Senior Notes issuance, the Company exercised the accordion feature on our secured credit facility, which increased the borrowing limit by $150 million to $1.5 billion.

On February 24, 2012, the Company completed the disposition of our non-core 2.2% interest in the Weyburn unit in Saskatchewan for gross proceeds of $105 million.

On March 16, 2012, the Company completed the disposition of certain non-core assets in southeast Saskatchewan for gross proceeds of $427 million.

On April 30, 2012, the borrowing limit on our secured credit facility was reduced to $1.4 billion to reflect the issuance of the Senior Notes and the disposition of assets, and the maturity was extended to June 2015. The facility had the potential to be increased to $1.5 billion under an accordion feature.

During the first three quarters of 2012, the Company repurchased 3,827,000 Common Shares under our NCIB at an average price of $13.51. In September 2012, we renewed our NCIB. In accordance with the renewed NCIB, the Company was authorized to repurchase up to 8,672,729 Common Shares from time to time until September 18, 2013. We did not repurchase any Common Shares under this renewed NCIB.

On December 3, 2012, the Company acquired a total of 16,605,900 shares of Arcan Resources Ltd. ("**Arcan**"), representing approximately 17% of the outstanding shares of Arcan at that time. Arcan is a junior oil producer listed on the TSX Venture Exchange with the majority of its assets located in the Swan Hills area of central Alberta. The shares were acquired by the Company for investment purposes. The Company's ownership interest was significantly diluted in 2015 and, accordingly, we are no longer an insider of Arcan.

On December 27, 2012, the Company announced that holders of US$293.4 million principal amount of Convertible Notes had exercised their right to have the Company repurchase their Convertible Notes and that the Company had elected to satisfy such repurchase in cash.

On December 31, 2012, the Company completed the Petrobank Reorganization, pursuant to which Old Petrobank effectively distributed the 107.8 million Common Shares of the Company owned by it to its shareholders. The Petrobank Reorganization resulted in the market float of the Company increasing from approximately 83 million Common Shares to approximately 191 million Common Shares.

In connection with the Petrobank Reorganization, the Company implemented a share dividend plan effective January 2013, allowing certain shareholders to receive dividends on their Common Shares in additional Common Shares at a five percent discount to the current market price of the Common Shares.

Year Ended December 31, 2013

In April 2013, the term of the Company's credit facility was extended to June 2016, with the same general terms and conditions.

At the Company's annual shareholder meeting held on May 22, 2013, shareholders approved the change of name of the Company from "PetroBakken Energy Ltd." to "Lightstream Resources Ltd." On May 28, 2013, the Common Shares of the Company began trading on the TSX under the new corporate name and under the new stock symbol "LTS".

In November 2013, we renewed our NCIB. In accordance with the renewed NCIB, Lightstream was authorized to repurchase up to 17,051,793 Common Shares from time to time until November 11, 2014. In 2013, we did not repurchase any Common Shares under our NCIB.

On November 21, 2013, Lightstream announced the termination of our dividend reinvestment plan and share dividend plan and the reduction of our dividend by 50% to $0.04 per month. These changes became effective for the December 2013 dividend paid in January 2014.

Year Ended December 31, 2014

In April 2014, the term of the Company's credit facility was extended to June 2017 and the lending amount was reduced by $100 million to $1.3 billion, to reflect asset dispositions that had occurred.

In 2014, we sold $729 million of non-core assets representing approximately 6,315 boed of production (79% liquids) and 20.9 million boe of proved plus probable reserves through a number of transactions. The majority of the assets sold were non-core southeast Saskatchewan conventional assets, including two working interest asset sales and one royalty interest asset sale. The proceeds were used to reduce overall corporate debt.

Following the asset dispositions, on September 30, 2014 the maximum lending amount of our secured term credit facility was reduced by $150 million to $1.15 billion (before the optional accordion feature that permits an increase by a further $100 million).

In 2014, we repurchased US$100 million principal amount of outstanding Senior Notes in two separate transactions for an aggregate purchase price of US$97.7 million, including accrued interest. The repurchased Senior Notes were retired, leaving a total of US$800 million aggregate principal amount of Senior Notes outstanding.

In November 2014, we renewed our NCIB authorizing us to repurchase up to 19,182,776 Common Shares from time to time until November 11, 2015. In 2014, we repurchased 3.5 million Common Shares under our NCIB and returned them to treasury.

On December 15, 2014, in response to falling commodity prices, Lightstream announced a reduction to our dividend of 62.5% from $0.04 per Common Share to $0.015 per Common Share commencing with the December 2014 dividend paid in January 2015.

Recent Developments

On January 19, 2015 we announced the suspension of our dividend program due to continued low WTI oil prices.

DESCRIPTION OF OUR BUSINESS

General

Lightstream is engaged in the exploration, development and production of oil and natural gas reserves in the provinces of Alberta, British Columbia and Saskatchewan with a focus on light oil. Our principal operating areas include southeast Saskatchewan in the Bakken and Mississippian formations, central Alberta in the Cardium formation and north-central Alberta in the Swan Hills area. Our properties and assets consist of proved producing (as defined herein) crude oil and natural gas reserves, proved plus probable (as defined herein) crude oil and natural gas reserves not yet on production and land.

We develop our properties through a detailed technical analysis of information including reservoir characteristics, oil in place, recovery factors and the application of enhanced recovery techniques and optimizations. Our focus has always been to increase the efficiency of our oil production in a cost effective manner through a number of techniques, including, but not limited to enhanced oil recovery through natural gas injection and other fluids, optimization through millouts, cleanouts, high volume lift installations or casing gas compressor installations and slick-water fracturing. Technological advancements such as these allow us to increase our recovery factors while potentially lowering our decline rates and operating costs.

Strategy

Lightstream's long term strategy is to deliver accretive production and reserves growth and value for the benefit of shareholders. Under our business model, we strive to develop new resource plays that have large oil-in-place, apply our knowledge, experience and the latest technologies to grow production and use the excess cash generated to explore new opportunities and ultimately pay dividends to shareholders. As our production base matures, the base decline rate typically moderates allowing us to generate higher free operating cash flow.

Since third quarter 2014, WTI oil prices have continued to decline to five year lows. As a result, our strategy for 2015 is to adopt a conservative capital program while suspending our dividend program with the objective of ensuring that our expenditures will be funded through cash flow, without an increase in total debt levels. In this low oil price environment, we are focused on the financial viability and long term prospectivity of the Company.

Specialized Skill and Knowledge

The Company believes our success is dependent on the performance of our management and employees, many of whom have specialized knowledge and skills relating to oil and gas operations and public company management. We believe that we have adequate personnel with the specialized skills required to successfully carry out our operations.

Environmental, Safety and Social Responsibility

Lightstream is committed to managing and operating in a safe, efficient and environmentally responsible manner in association with our industry partners and is committed to improving our environment, health, safety and social performance. We have implemented environment, health and safety ("**EH&S**") policies, procedures and programs to meet or exceed industry standards and legislative requirements.

We support and endorse the Environmental Operating Procedures developed by the Canadian Association of Petroleum Producers. Key environmental considerations include air quality and climate change, water conservation, spill management, waste management plans, lease and right-of-way management, natural and historic resources protection, and liability management (including site assessment and remediation). These practices and procedures apply to our employees and we monitor all activities and make reasonable efforts to ensure that companies who provide services to us will operate in a manner consistent with our environmental policy.

Our environmental management plan and operating guidelines focus on minimizing the environmental impact of our operations while meeting regulatory requirements and corporate standards. We maintain an active comprehensive integrity monitoring and management program for our surface piping, facilities, storage tanks and underground pipelines. Contingency plans are in place for a timely response to an environmental event and abandonment, remediation and reclamation programs are in place and utilized to restore the environment. We also perform a detailed due diligence review as part of the acquisition process to determine whether the acquired assets are in regulatory and environmental compliance and assess any liabilities with respect thereto.

Lightstream expects to incur abandonment and site reclamation costs as existing oil and gas properties are abandoned and reclaimed. In 2014, expenditures for normal compliance with environmental regulations as well as expenditures beyond normal compliance were $10 million and the Company does not anticipate a material change in such costs in 2015. See "Additional Information Relating to Reserves Data – Additional Information Concerning Abandonment and Reclamation Costs".

<u>Risk Management</u>

Factors outside our control impact, to varying degrees, the prices we receive for production and the associated operating expenses we incur. These include but are not limited to:

(a) world market forces and political conditions that impact the global prices for crude oil, including the ability of OPEC to adjust production and influence oil prices and the risk of hostilities in the Middle East and other regions throughout the world;

(b) North American market forces, most notably shifts in the balance between supply and demand for crude oil and natural gas and the implications for the price of crude oil and natural gas;

(c) increases or decreases in crude oil quality differentials and their implications for prices received by us;

(d) the impact of changes in the exchange rate between Canadian and U.S. dollars on prices received by us for our crude oil and natural gas;

(e) availability, proximity and capacity of oil and gas gathering systems, pipeline and processing facilities;

(f) price and availability of alternative fuels; and

(g) the effect of energy conservation measures and government regulations.

Fluctuations in commodity prices, quality differentials and foreign exchange and interest rates, among other factors, are outside of our control and yet can have a significant impact on the level of cash we have available for capital investment and potential payment of dividends to shareholders. To mitigate a portion of these risks, we actively initiate, manage and disclose the effects of our hedging activities. Our strategy for crude oil and natural gas production is to hedge to a maximum of 50% of our existing production after royalties, on a rolling three year basis, at the discretion of management. All hedging activities are governed by our risk management policies and are regularly reviewed by the Board. We further mitigate our risk by transacting with a number of counterparties for the sale of our oil and natural gas, thereby limiting our exposure to any one counterparty.

Lightstream also from time to time enters into foreign exchange contracts to limit exposure to variability in exchange rates on US dollar interest payments on the Senior Notes and Convertible Notes, thereby providing increased stability of cash flows.

Employees

As at December 31, 2014, Lightstream had 433 full-time employees. Through a combination of normal attrition and workforce reductions that have been undertaken by Lightstream, the size of Lightstream's workforce has been reduced since December 31, 2014. As at February 28, 2015, Lightstream had 369 employees.

Principal Producing Properties

The following table summarizes our principal producing properties as of December 31, 2014 based on the Sproule Report using forecast prices and costs. The table also contains our average daily production of oil, natural gas and NGL for the year ended December 31, 2014.

Summary of Company Interest at December 31, 2014[1]
(Forecast Prices and Costs)[2]

Field	P+P Reserves Mboe[3]	P+P Value Before Tax at 10% DR [4]$MM	2014 Oil Production bbl/d	2014 Gas Production MMcf/d	2014 NGL Production bbl/d	2014 Total Production BOE/d[3]
Bakken and Conventional (SE Saskatchewan)	69,645	1,852	15,525	7,148	1,108	17,824
Cardium	79,037	1,143	10,627	37,348	1,754	18,605
AB/BC	12,540	155	2,389	7,922	282	3,991
Total	161,222	3,150	28,541	52,418	3,144	40,420

Notes:

1. The estimates of reserves and Future Net Revenue for individual properties may not reflect the same confidence level as estimates of reserves and Future Net Revenue for all properties, due to the effects of aggregation.
2. Forecast prices are shown under the heading "Pricing Assumptions – Forecast Prices and Costs".
3. Natural gas has been converted to barrels of oil equivalent on the basis of six (6) Mcf of natural gas being equal to one barrel of oil.
4. Estimated Future Net Revenues disclosed do not represent fair market value.

Bakken Business Unit (Saskatchewan)

Lightstream's Saskatchewan assets produce light oil primarily from the Bakken and conventional Mississippian formations. Lightstream has over 604 gross (502 net) sections of land in Saskatchewan and has identified more than 1,090 drilling locations. These assets lie within mature oilfields with extensive infrastructure, and the majority of our Bakken business unit assets are tied into operated gathering systems and processing facilities with pipeline access. Production is relatively mature in the Bakken business unit, providing us with free cash flow in excess of capital investment.

In 2014, Lightstream drilled a total of 39 wells in the southeast Saskatchewan area, of which 19 targeted the Bakken formation and 20 targeted the Mississippian formation. Average production for 2014 was 17,824 boepd, of which 14,585 boepd was produced from the Bakken business unit and 3,239 was produced from the Conventional business unit. In 2015, Lightstream anticipates drilling 7 net wells (5 Bakken and 2 Mississippian) under our moderate capital investment program.

In southeast Saskatchewan, Lightstream is using natural gas injection for Enhanced Oil Recovery (EOR). EOR is designed to attenuate declining production by increasing pressure through the injection of natural gas into the reservoir. In 2014, we expanded our Creelman EOR unit to 13 sections where we have four gas injection wells, two of which were drilled in 2014 and began injecting gas in early 2015. We plan to advance the development of the Bakken gas flood program in 2015 through two well conversions to gas injectors.

We continued to invest in optimization activities on our southeast Saskatchewan assets in 2014, which increased production by over 1,100 boepd. Optimization well investments include millouts, cleanouts, high volume lift and well specific compression. We will continue to review wells in 2015 to identify optimization opportunities.

On December 15, 2014, we announced our plan to sell all or part of the Bakken Business Unit over the next 24 months to reduce debt and position the Company for future growth.

Cardium Business Unit

Lightstream's Cardium business unit assets primarily produce light oil from the Cardium formation. Lightstream holds a land position of approximately 457 gross (324 net) sections, of which approximately 274 net sections represent Cardium formation rights stretching from Calgary to Edmonton, Alberta. Average production in our Cardium business unit was 18,605 boepd in 2014.

In 2014, we drilled 51 net wells in the Cardium business unit and anticipate drilling 8 net wells in 2015. The 2015 program includes plans to drill 1.8 net Fahler wells in the Brazeau area with the remainder being Cardium pad wells in West Pembina. We have continued to optimize our drilling and completion techniques in the Cardium and have made key investments to de-bottleneck infrastructure and reduce operating expenses. We expect the Cardium to continue to represent a growth area for the Company and this business unit generated free cash flow in excess of capital investments in 2014 and is expected to continue to do so in 2015.

Alberta/BC Business Unit

Lightstream established a material land position in Alberta with over 514 gross (476 net) undeveloped sections in emerging oil and liquid-rich gas focused resource plays, which we believe provide opportunities for future production growth. In 2014 we focused the majority of our investment for this business unit on developing the Swan Hills formation of the Deer Mountain region, which is a light oil resource style play.

We drilled 8 net wells in the Swan Hills area in 2014 and made significant investments in a 3,500 bbl/d battery and pipeline infrastructure to accommodate our existing and future development wells. Our current inventory sits at 100 locations. Average production in our Alberta/BC business unit was 3,991 boepd in 2014 with over half of the production (2,083 boepd) coming from our Swan Hills development.

Lightstream also has a significant land position in the Horn River natural gas resource play in northeast British Columbia, with a large inventory of potential drilling locations. This asset requires higher sustained gas prices for development, and we currently do not plan to invest capital in this asset in the current economic environment.

STATEMENT OF RESERVES DATA

Notes on Reserves Data

Crude oil, natural gas liquids and natural gas reserves estimates presented in the Sproule Report are based on the definitions and guidelines contained in the COGE Handbook. A summary of those definitions is set forth below:

Reserve Categories

Reserves are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, as of a given date forward, based on:

- analysis of drilling, geological, geophysical and engineering data;
- the use of established technology; and
- specified economic conditions which are generally accepted as being reasonable, and shall be disclosed.

Reserves are classified according to the degree of certainty associated with the estimates.

Proved reserves are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.

Probable reserves are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves.

Other criteria that must also be met for the categorization of reserves are provided in the COGE Handbook.

Each of the reserve categories (proved and probable) may be divided into developed and undeveloped categories:

Developed reserves are those reserves that are expected to be recovered from existing wells and installed facilities or, if facilities have not been installed, that would involve a low expenditure (for example, when compared to the cost of drilling a well) to put the reserves on production. The developed category may be subdivided into producing and non-producing.

Developed producing reserves are those reserves that are expected to be recovered from completion intervals open at the time of the estimate. These reserves may be currently producing or, if shut-in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainty.

Developed non-producing reserves are those reserves that either have not been on production, or have previously been on production, but are shut-in, and the date of resumption of production is unknown.

Undeveloped reserves are those reserves expected to be recovered from known accumulations where a significant expenditure (for example, when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves category (proved or probable) to which they are assigned.

In multi-well pools it may be appropriate to allocate total pool reserves between the developed and undeveloped categories or to subdivide the developed reserves for the pool between developed producing and developed non-producing. This allocation should be based on the estimator's assessment as to the reserves that will be recovered from specific wells, facilities and completion intervals in the pool and their respective development and production status.

Levels of Certainty for Reported Reserves

The qualitative certainty levels referred to in the definitions above are applicable to individual reserve entities (which refers to the lowest level at which reserves calculations are performed) and to reported reserves (which refers to the highest level sum of individual entity estimates for which reserves are presented). Reported reserves should target the following levels of certainty under a specific set of economic conditions:

- at least a 90 percent probability that the quantities actually recovered will equal or exceed the estimated proved reserves; and
- at least a 50 percent probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable reserves.

A qualitative measure of the certainty levels pertaining to estimates prepared for the various reserves categories is desirable to provide a clearer understanding of the associated risks and uncertainties. However, the majority of reserves estimates will be prepared using deterministic methods that do not provide a mathematically derived quantitative measure of probability. In principle, there should be no difference between estimates prepared using probabilistic or deterministic methods.

Additional clarification of certainty levels associated with reserve estimates and the effect of aggregation is provided in the COGE Handbook.

The estimates of reserves and future net revenue for individual properties may not reflect the same confidence level as estimates of reserves and future net revenue for all properties, due to the effects of aggregation.

Estimated future well abandonment and disconnect have been included in the Sproule Report calculation of net reserves for all wells that are assigned reserves.

Columns contained in this Annual Information Form may not add due to rounding.

<u>Disclosure of Reserves Data</u>

The reserves data set forth herein is based upon evaluations completed by Sproule. The reserves data contained herein summarizes the oil, NGLs, and natural gas reserves of the Company and the net present values of future net revenue for these reserves using forecast prices and costs. The reserves data complies with the requirements of NI 51-101. Lightstream engaged Sproule to provide evaluations of proved and probable reserves. Certain additional information not required by NI 51-101 has been included herein to provide readers with further information regarding our properties.

All of the Company's reserves are in Canada (specifically, in the provinces of Saskatchewan, Alberta and British Columbia).

In preparing the Sproule Report, basic information was provided to Sproule by Lightstream, which included land data, well information, geological information, reservoir studies, estimates of on-stream dates, contract information, current hydrocarbon product prices, operating cost data, capital budget forecasts, financial data and future operating plans. Other engineering, geological or economic data required to conduct the evaluations and upon which the Sproule Report is based, was obtained from public records, other operators and from Sproule's non-confidential files. The extent and character of ownership and the accuracy of all factual data supplied for the Sproule Report, from all sources, was accepted by Sproule as represented.

The tables and information contained herein show the estimated share of Lightstream's crude oil, natural gas and NGL reserves in our Canadian properties and the present value of estimated future net revenue for these reserves, after provision for Alberta gas cost allowance, using forecast prices and costs as indicated.

All evaluations and reviews of future net cash flow are stated prior to any provision for interest costs or general and administrative costs and after the deduction of estimated future capital expenditures for wells to which reserves have been assigned and estimated future well abandonment costs. It should not be assumed that the estimated future net cash flow shown below is representative of the fair market value of the Company's properties. There is no assurance that such price and cost assumptions will be attained and variances could be material. The recovery and reserve estimates of crude oil, NGL and natural gas reserves provided herein are

estimates only and there is no guarantee that the estimated reserves will be recovered. Actual crude oil, NGL and natural gas reserves may be greater than or less than the estimates provided herein.

The reserves data contained herein is based on Sproule's price forecasts, as of December 31, 2014. Reserves information has been provided on a gross and net basis in accordance with NI 51-101. The Company has also previously publicly disclosed our reserves on a "company interest" basis (being the gross volumes plus the Company's share of royalty interests in reserves), which results in an additional 480 MMboe of proved plus probable reserves attributable to the Company. "Company interest" is not a term defined by NI 51-101 and may not be comparable to reserves estimates disclosed by others in accordance with NI 51-101.

Summary of Oil and Gas Reserves – Forecast Prices and Costs

Gross Reserves	Oil		Conventional Natural Gas				
	Light and Medium Oil	Heavy Oil	Shale Gas	Associated & Non-Associated	Coalbed Methane	Natural Gas Liquids	Total
	Mbbls	Mbbls	MMcf	MMcf	MMcf	Mbbls	Mboe
Proved							
Developed Producing	45,076	0	0	95,841	60	5,863	66,923
Developed Non-Producing	1,652	13	0	3,787	0	225	2,521
Undeveloped	23,707	0	0	42,360	0	2,699	33,466
Total Proved	70,435	13	0	141,988	60	8,788	102,910
Probable	42,492	9	0	65,681	593	4,285	57,832
Total Proved plus Probable	112,927	22	0	207,669	653	13,073	160,742

Net Reserves	Oil		Conventional Natural Gas				
	Light and Medium Oil	Heavy Oil	Shale Gas	Associated & Non-Associated	Coalbed Methane	Natural Gas Liquids	Total
	Mbbls	Mbbls	MMcf	MMcf	MMcf	Mbbls	Mboe
Proved							
Developed Producing	39,666	0	0	83,156	65	4,594	58,129
Developed Non-Producing	1,455	12	0	3,233	0	183	2,189
Undeveloped	21,430	0	0	37,893	0	2,216	29,961
Total Proved	62,551	12	0	124,282	65	6,992	90,279
Probable	37,284	7	0	57,937	500	3,497	50,530
Total Proved plus Probable	99,835	19	0	182,219	566	10,490	140,809

Net Present Value of Future Net Revenue – Forecast Prices and Costs

	Before Future Income Tax Expenses and Discounted at				
	0% (M$)	5% (M$)	10% (M$)	15% (M$)	20% (M$)
Proved					
Developed Producing	2,594,730	2,028,331	1,667,201	1,419,940	1,241,058
Developed Non-Producing	89,667	72,104	60,002	51,267	44,712
Undeveloped	888,720	525,197	318,019	190,239	106,721
Total Proved	3,573,117	2,625,631	2,045,222	1,661,446	1,392,491

	Before Future Income Tax Expenses and Discounted at				
	0%	5%	10%	15%	20%
	(M$)	(M$)	(M$)	(M$)	(M$)
Probable	2,508,100	1,589,834	1,105,190	816,937	630,349
Total Proved plus Probable	6,081,217	4,215,466	3,150,412	2,478,383	2,022,841

	After Future Income Tax Expenses and Discounted at				
	0%	5%	10%	15%	20%
	(M$)	(M$)	(M$)	(M$)	(M$)
Proved					
Developed Producing	2,367,179	1,889,006	1,576,785	1,358,590	1,197,944
Developed Non-Producing	65,833	54,240	46,267	40,488	36,111
Undeveloped	655,053	368,414	204,799	104,344	39,261
Total Proved	3,088,065	2,311,660	1,827,852	1,503,422	1,273,316
Probable	1,848,916	1,160,332	797,339	582,160	443,602
Total Proved plus Probable	4,936,981	3,471,992	2,625,191	2,085,582	1,716,918

	Unit Value Before Income Tax Discounted at 10%/year ($/BOE)
Proved	
Developed Producing	28.68
Developed Non-Producing	27.41
Undeveloped	10.61
Total Proved	22.65
Probable	21.87
Total Proved Plus Probable	22.37

Additional Information Concerning Future Net Revenue – Forecast Prices and Costs (Undiscounted)

(Undiscounted)	Revenue (M$)	Royalties (M$)	Operating Costs (M$)	Development Costs (M$)	Well Abandonment/Other Costs (M$)	Future Net Revenue Before Income Taxes (M$)	Income Taxes (M$)	Future Net Revenue After Income Taxes (M$)
Total Proved	8,374,107	956,877	2,759,248	880,024	204,842	3,573,117	485,052	3,088,065
Total Proved plus Probable	13,691,445	1,608,974	4,265,060	1,450,567	285,626	6,081,217	1,144,236	4,936,981

Future Net Revenue by Product Type – Forecast Prices and Costs

	Future Net Revenue Before Income Taxes and Discounted at 10% (M$)	Per Unit Future Net Revenue Before Income Taxes and Discounted at 10% ($/BOE)
Proved Reserves		
Light and Medium Crude Oil[1]	2,038,169	23.63
Heavy Oil[1]	-2	-0.14
Coalbed Methane	55	5.04
Natural Gas Liquids[2]	29,356	5.04
Shale Gas	0	-
Other Income[3]	-22,356	-
Proved plus Probable Reserves		
Light and Medium Crude Oil[1]	3,132,902	24.63
Heavy Oil[1]	73	23.24
Coalbed Methane	-5	0.82
Natural Gas Liquids[2]	42,325	9.32
Shale Gas	0	-
Other Income[3]	-24,883	-

Notes:

1. Including solution gas and other by-products.
2. Including by-products, but excluding solution gas from oil wells.
3. Represents facility costs that are not attributed to future net revenues from specified product types.

Pricing Assumptions – Forecast Prices and Costs

Sproule employed the following pricing and exchange rate assumptions as of December 31, 2014 in the Sproule Report in estimating reserves data using forecast prices and costs. Inflation was assumed at 1.5% per year. The weighted average historical prices received by Lightstream for 2014 are also reflected in the table below.

Year	WTI Cushing Oklahoma ($US/bbl)	Canadian Light Sweet Crude 40° API ($Cdn/bbl)	Cromer LSB 35º API ($Cdn/bbl)	Natural Gas[1] AECO Gas Price ($/MMBtu)	Pentanes Plus FOB Field Gate ($Cdn/bbl)	Butanes FOB Field Gate ($Cdn/bbl)	Exchange Rate[2] ($US/ $Cdn)
2014 (Actual)	93.00	94.18	93.26	4.50	102.33	68.02	0.905
2015	65.00	70.35	69.85	3.32	78.60	50.34	0.850
2016	80.00	87.36	86.86	3.71	97.60	62.51	0.870
2017	90.00	98.28	97.78	3.90	109.80	70.32	0.870
2018	91.35	99.75	99.25	4.47	111.44	71.37	0.870
2019	92.72	101.25	100.75	5.05	113.12	72.44	0.870

Escalated at 1.5% per year thereafter.

Notes:

1. This summary table identifies benchmark reference pricing schedules that might apply to a reporting issuer.
2. Exchange rates used to generate the benchmark reference prices in this table.

Reconciliation of Gross Reserves

The following table sets forth a reconciliation of Lightstream's gross reserves as at December 31, 2014, derived from the Sproule Report using forecast prices and cost estimates.

Proved	Light and Medium Oil (Mbbl)	Heavy Oil (Mbbl)	Coalbed Methane (MMcf)	Associated, Non-Associated and Solution Gas (MMcf)	Shale Gas (MMcf)	Natural Gas Liquids (Mbbl)
Balance at December 31, 2013	89,997	45	63	154,909	1,759	7,987
Extensions and Improved Recovery	1,222	0	0	682	0	83
Infill Drilling	4,720	0	0	8,225	0	652
Technical Revisions	-3,859	-23	13	8,131	0	1,798
Discoveries	0	0	0	0	0	0
Acquisitions	40	0	0	29	0	6
Dispositions	-10,946	0	0	-9,385	-1,662	-532
Economic Factors	-407	-5	-1	-1,746	0	-64
Production	-10,333	-4	-15	-18,857	-97	-1,142
Balance at December 31, 2014	70,435	13	60	141,988	0	8,788

Probable	Light and Medium Oil (Mbbl)	Heavy Oil (Mbbl)	Coalbed Methane (MMcf)	Associated, Non-Associated and Solution Gas (MMcf)	Shale Gas (MMcf)	Natural Gas Liquids (Mbbl)
Balance at December 31, 2013	56,289	25	600	83,317	337	4,540
Extensions and Improved Recovery	2,240	0	0	1,660	0	192
Infill Drilling	2,999	0	0	4,708	0	402
Technical Revisions	-12,889	-13	-7	-16,611	0	-517
Discoveries	0	0	0	0	0	0
Acquisitions	14	0	0	11	0	2
Dispositions	-6,149	0	0	-7,110	-337	-324
Economic Factors	-13	-3	0	-296	0	-11
Production	0	0	0	0	0	0
Balance at December 31, 2014	42,492	9	593	65,680	0	4,286

Proved + Probable	Light and Medium Oil (Mbbl)	Heavy Oil (Mbbl)	Coalbed Methane (MMcf)	Associated, Non-Associated and Solution Gas (MMcf)	Shale Gas (MMcf)	Natural Gas Liquids (Mbbl)
Balance at December 31, 2013	146,286	71	663	238,226	2,096	12,527
Extensions and Improved Recovery	3,462	0	0	2,342	0	275
Infill Drilling	7,719	0	6	12,933	0	1,055
Technical Revisions	-16,747	-36	0	-8,480	0	1,281
Discoveries	0	0	0	0	0	0
Acquisitions	54	0	0	40	-1,999	8
Dispositions	-17,094	0	0	-16,495	0	-856
Economic Factors	-420	-8	-1	-2,042	-97	-75
Production	-10,333	-4	-15	-18,857	0	-1,142
Balance at December 31, 2014	112,927	22	653	207,668	0	13,073

ADDITIONAL INFORMATION RELATING TO RESERVES DATA

Undeveloped Reserves

The following table sets forth the volumes of proved undeveloped reserves that were first attributed in each of the three most recent financial years and, in the aggregate, before that time:

	Light and Medium Crude Oil (Mbbl)	Natural Gas (MMcf)	Natural Gas Liquids (Mbbl)
Prior to 2012	29,918	24,244	1,613
2012	8,364	16,348	727
2013	5,077	8,300	435
2014	4,941	7,340	662

The following table sets forth the volumes of probable undeveloped reserves that were first attributed in each of the three most recent financial years and, in the aggregate, before that time:

	Light and Medium Crude Oil (Mbbl)	Natural Gas (MMcf)	Natural Gas Liquids (Mbbl)
Prior to 2012	32,943	30,456	1,913
2012	9,179	16,124	747
2013	5,778	6,295	421
2014	4,821	5,847	555

Lightstream attributes proved and probable undeveloped reserves based on accepted engineering and geological practices as defined under NI 51-101. These practices include the determination of reserves based on the presence of commercial test rates from either production tests or drill stem tests, extensions of known accumulations based upon both geological and geophysical information, and the optimization of existing fields.

Subject to the success of operations, within the next two years, Lightstream has the following plans regarding the development of proved and probable undeveloped reserves:

1. Proved undeveloped reserves were assigned on the basis of the regional nature of the producing formations. Performance expectations are based on offset well production. Well locations typically were assigned where economic production has been demonstrated by wells in offsetting spacing units. The Sproule Report has assigned proved undeveloped reserves to 160 net light oil well locations in the Bakken business unit, 143 net light oil locations in the Cardium business unit and 38 net light oil and natural gas locations in the Alberta/BC business unit. For Lightstream's total proved undeveloped program, approximately 24% of the capital is forecast to be spent in 2015 and approximately 47% of the forecasted capital scheduled to be spent by the end of 2016.

2. Probable undeveloped reserves in the Bakken properties are generally assigned adjacent to proved well locations. The Bakken in southeast Saskatchewan produces light oil plus solution gas and associated liquids based on typical gas/oil ratios and typical condensate yields where the gas is gathered. The Sproule Report has assigned probable undeveloped reserves to 115 net light oil well locations in the Bakken business unit, 42 net light oil locations in the Cardium business unit and 6 net light oil and natural gas locations in the Alberta/BC business unit. For Lightstream's total probable undeveloped program, approximately 22% of the capital is forecast to be spent in 2015 and over approximately 45% of the forecasted capital is scheduled to be spent by the end of 2016.

Under Lightstream's current 2015 drilling plan, we expect to drill 15 net wells in aggregate, depending on a number of factors including commodity prices, capital costs, well results, economic conditions, availability of equipment and personnel, weather and access to drilling locations. See "*Risk Factors*" for a complete list of factors that may impact our drilling plan. Wells are primarily expected to be drilled in central Alberta on our Cardium property, in southeast Saskatchewan, on both the Bakken and conventional Mississippian properties.

Undeveloped reserves, like all projects, are subject to competition for capital and consequently may be delayed or accelerated from time to time.

Future Development Costs

The table below sets out the total development costs deducted in the estimation in the Sproule Report of future net revenue attributable to proved reserves and proved plus probable reserves (using forecast prices and costs).

Year	Total Proved Reserves	Total Proved Plus Probable Reserves
	(CDN M$)	(CDN M$)
2015	208,642	314,280
2016	202,778	335,791
2017	270,470	439,902
2018	149,555	263,532
2019	41,745	70,023
Thereafter	6,834	27,037
Total undiscounted	880,024	1,450,567
Total discounted at 10%	725,846	1,188,735

Future development costs are expected to be funded by internally generated cash flow, and if necessary from a combination of potential debt and/or equity financings, the costs of which are not expected to have an effect on the reserves or future net revenue.

2015 Production Estimates

The following table sets out the volume of the Company's production estimated by Sproule for the year ended December 31, 2015 which is reflected in the estimate of future net revenue disclosed in the tables contained in this Annual Information Form.

Reserves Category	Light and Medium Oil Gross (bbl/d)	Heavy Oil Gross (bbl/d)	Natural Gas[1] Gross (Mcf/d)	Coalbed Methane Gross (Mcf/d)	Shale Gas Gross (Mcf/d)	Natural Gas Liquids Gross (bbl/d)	Oil Equivalent Gross (boe/d)
Total Proved Producing	19,742	0	39,727	33	0	2,548	28,916
Total Proved	23,066	15	43,656	33	0	2,889	33,250
Total Proved Plus Probable	27,575	15	49,271	35	0	3,318	39,125

Note:

1. Natural Gas includes all solution gas, plus associated and non-associated gas. Natural gas is separate from Coalbed Methane and Shale Gas.

Significant Factors or Uncertainties Affecting Reserves Data

There are numerous uncertainties inherent in estimating quantities of proved reserves, including many factors beyond the control of the Company. The reserve data included herein represents estimates only. In general, estimates of economically recoverable oil and natural gas reserves and the future net cash flows therefrom are based upon a number of variable factors and assumptions, such as historical production from the properties, the assumed effects of regulation by governmental agencies and future operating costs, all of which may vary considerably from actual results. All such estimates are to some degree speculative, and classifications of reserves are only attempts to define the degree of speculation involved. For those reasons, estimates of the economically recoverable oil and natural gas reserves attributable to any particular group of properties, classification of such reserves based on risk of recovery and estimates of future net revenues expected therefrom, prepared by different engineers or by the same engineers at different times, may vary substantially. The actual production, revenues, taxes and development and operating expenditures of the Company with respect to these reserves will vary from such estimates, and such variances could be material.

Estimates with respect to proved reserves that may be developed and produced in the future are often based upon volumetric calculations and upon analogy to similar types of reserves rather than actual production history. Estimates based on these methods are generally less reliable than those based on actual production history. Subsequent evaluation of the same reserves based upon production history will result in variations, which may be substantial, in the estimated reserves.

Consistent with the securities disclosure legislation and policies of Canada, the Company has used forecast prices and costs in calculating reserve quantities included herein. Actual future net cash flows also will be affected by other factors such as actual production levels, supply and demand for oil and natural gas, curtailments or increases in consumption by oil and natural gas purchasers, changes in governmental regulation or taxation and the impact of inflation on costs.

Oil and Gas Wells

The following table summarizes Lightstream's interests, by region and on a consolidated basis, as at December 31, 2014, in oil and natural gas wells which are producing or which are considered capable of production and in non-producing wells. All non-producing wells considered capable of production have been standing for a period of less than one year, are within economic distance of transportation facilities and are classified as proved developed non-producing reserves in the Sproule Report.

	Producing				Non-Producing			
	Oil		Natural Gas		Oil		Natural Gas	
Area	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Saskatchewan	1,328	950	7	5	61	39	6	3
Alberta	742	541	292	228	148	105	135	108
British Columbia	1	1	24	18	6	2	16	15
Manitoba	-	-	-	-	6	-	-	-
Total Lightstream	**2,071**	**1,492**	**323**	**251**	**215**	**146**	**157**	**126**

Land Holdings – Consolidated

The land holdings of the Company, including those that are undeveloped, by region and on a consolidated basis, as at December 31, 2014, are set forth in the following table (in 000s of acres unless otherwise noted).

	Developed		Undeveloped[1]		Total		Avg.
Area	Gross	Net	Gross	Net	Gross	Net	WI%
Saskatchewan	184	141	203	180	387	321	82.95%
Alberta	355	256	467	407	822	663	80.66%
British Columbia	35	26	39	31	74	57	77.03%
Manitoba	0	0	0	0	0	0	00.00%
Northwest Territories	0	0	6	2	6	2	33.33%
Total Lightstream	574	423	715	620	1,289	1,043	80.92%

Note:

1. Provincial governments (for Crown mineral lands) and private mineral owners (for freehold mineral lands) in Canada grant rights to explore for and produce oil and natural gas under leases, licenses and permits, which may be continued, indefinitely by producing under these lease agreements. Accordingly, to preserve this acreage the Company is committed to bring wells on production.

The Company expects that rights to explore, develop and exploit 81,754 net acres of our undeveloped land in Canada are scheduled to expire by December 31, 2015. The Company will attempt to extend some of this expiring acreage through any continuation provisions we are afforded under the individual title documents and applicable governmental regulations.

Forward Contracts and Future Commitments

See Note 17, *"Financial Instruments and Financial Risk Management"*, and Note 19, *"Commitments and Contingencies"*, to the Company's December 31, 2014 consolidated financial statements, which information is incorporated herein by reference, and was filed on SEDAR March 13, 2015 under the Company's profile at www.sedar.com.

Additional Information Concerning Abandonment and Reclamation Costs

Abandonment and reclamation costs were estimated for all legal obligations associated with the retirement of long-lived tangible assets such as wells, facilities and plants based on market prices or on the best information available where no market price was available. For obligations in Canada, the estimated costs are then inflated at two percent over time until the actual retirement is expected to occur.

As at December 31, 2014, Lightstream expected to incur future abandonment and reclamation costs in respect to all of our net wells in Canada.

The total abandonment and reclamation costs net of salvage values of all Lightstream's operations, on a consolidated basis, are estimated to be $218.9 million on an undiscounted basis and $48.6 million discounted at 10 percent. In the next three financial years, Lightstream anticipates that approximately $23.4 million on an undiscounted basis and $20.2 million discounted at 10 percent will be incurred on abandonment and reclamation costs.

The future net revenue disclosed in the Sproule Report in this Annual Information Form does not contain an allowance for abandonment and reclamation costs for surface leases, facilities and pipelines. The Sproule Report deducted $177.8 million (undiscounted) and $24.0 million (discounted at 10 percent) for downhole abandonment and disconnect costs for wells to which reserves were assigned, on a total proved plus probable basis, of which a total of $1.2 million undiscounted ($1.0 million discounted at 10 percent) is estimated to be incurred in the next three financial years.

Tax Horizon

Lightstream has a Canadian tax pool balance of approximately $1.7 billion as at December 31, 2014, which can be used to shelter future taxable income. Based on the Sproule Report, Lightstream's exploration and development plans, and forecasted commodity pricing, Lightstream does not expect to pay income tax in Canada for at least the next 5 years. The following table summarizes the Company's Canadian tax pools as at December 31, 2014 (reflected net of partnership income earned in the 2014 calendar year that is taxable in 2015).

(000s)	Total
Canadian development expenses (CDE)	$ 919,769
Undepreciated capital costs (UCC)	448,472
Non-capital losses and Canadian exploration expenses (CEE)[1]	362,048
Common Share issuance and financing costs	12,201
Total tax pools	**$ 1,742,490**

Note:

1. Non-capital losses at December 31, 2014 were $357.0 million, prior to any reductions on account of partnership income.

Capital Expenditures

The following table summarizes capital expenditures related to the Company's activities for the year ended December 31, 2014.

($000s)	Total
Drilling, completions, equipping and recompletions	375,284
Facilities	72,181
Land	4,786
Seismic	1,701
Other [1]	17,868
Capital expenditures before acquisitions	**471,820**
Asset acquisitions	12,007
Asset dispositions	(724,463)
Total net capital expenditures	**(240,636)**

Note:

1. Includes health, safety and environmental, direct salaries and office furniture and fixtures.

Costs Incurred

The following table summarizes the property acquisition, exploration and development costs incurred for the year ended December 31, 2014.

	Acquisition Costs [1]			
	Proved	Unproved [2]	Exploration	Development
Total (M$)	8,018	5,939	8,092	452,460

Notes:

1. Pursuant to NI 51-101, "proved properties" are all properties to which proved reserves have been specifically attributed and "unproved properties" are properties to which no reserves have been specifically attributed.
2. Includes $1.9 million of land acquisition costs incurred by Lightstream in 2014, and $4.0 million of asset acquisition costs.

Exploration and Development

The following table summarizes the gross and net exploratory and development wells in which the Company participated during the year ended December 31, 2014.

	Exploration		Development		Total	
	Gross	Net	Gross	Net	Gross	Net
Oil	1	1	132	96	133	97
Natural Gas	-	-	3	1	3	1
Dry	-	-	-	-	-	-
Service Wells	-	-	1	1	1	1
Total	**1**	**1**	136	98	**137**	**99**
Success Rate	100%	100%	100%	100%	100%	100%

Lightstream's exploration and development plans are discussed under the heading *"Description of Our Business"*.

Production History

Production

The following table shows the Company's average working interest production volumes before deduction of royalties payable to others and average netbacks received for each of the last four fiscal quarters by product type.

	Three Months Ended				Year Ended
	Mar 31, 2014	June 30, 2014	Sept 30, 2014	Dec 31, 2014	Dec 31, 2014
Average daily production (1) (2)					
Light / medium oil and NGLs (bbl/d)	35,209	34,128	30,203	27,299	31,684
Natural gas (Mcf/d)	52,503	50,309	51,802	55,037	52,418
Total Lightstream (boe/d)	43,960	42,513	38,837	36,472	40,420

Notes:

1. NGLs have been included with light/medium oil as they are not considered material. NGLs represent approximately eight percent of Lightstream's total production.
2. Heavy oil has been included in light/medium oil as it is not considered material. Heavy oil represents less than one percent of Lightstream's total production.

The following table sets forth the Company's average daily production volumes, for each significant field and on a consolidated basis, for the twelve month period ended December 31, 2014.

	Lt/Med Oil and NGL (bbl)(1)	Gas (Mcf)	Total (boe)
Bakken	13,550	6,211	14,585
Conventional (SE SK)	3,082	937	3,238
Cardium (Central AB)	12,381	37,348	18,606
Alberta/BC	2,671	7,922	3,991
Total Lightstream	**31,684**	**52,418**	**40,420**

Note:

1. NGL's and heavy oil have been included with light/medium oil, as they are not considered to be material.

Netback by Product

Light/Medium Crude Oil and NGL Netback(4) ($ per bbl)

	Three Months Ended				Year Ended
	Mar 31, 2014	June 30, 2014	Sept 30, 2014	Dec 31, 2014	Dec 31, 2014
Average price received (1)	93.32	97.15	88.90	66.40	87.44
Royalties	14.27	14.64	14.22	11.27	13.71
Operating costs (2)	15.39	16.02	17.16	15.79	16.07
Netback (3)	63.66	66.49	57.52	38.34	57.66

Notes:

1. Net of transportation expenses.
2. Operating costs are expenses incurred in the operation of producing properties and include items such as field staff salaries, power, fuel, chemicals, repairs and maintenance, property taxes, processing and treating fees, overhead fees and other costs.
3. Excludes hedging activities.
4. Heavy oil has been included in light/medium oil as it is not considered to be material. Heavy oil represents less than one percent of Lightstream's total production.

Natural Gas Netback ($ per Mcf)

	Three Months Ended				Year Ended
	Mar 31, 2014	June 30, 2014	Sept 30, 2014	Dec 31, 2014	Dec 31, 2014
Average price received [1]	5.88	5.01	4.27	3.76	4.71
Royalties	0.28	0.30	0.20	0.21	0.25
Operating costs [2]	1.31	1.22	1.13	1.10	1.19
Netback [3]	4.29	3.49	2.94	2.45	3.28

Notes:

1. Net of transportation expenses.
2. Operating costs are expenses incurred in the operation of producing properties and include items such as field staff salaries, power, fuel, chemicals, repairs and maintenance, property taxes, processing and treating fees, overhead fees and other costs.
3. Excludes hedging activities.

CAPITAL STRUCTURE

Common Shares and Preferred Shares

The authorized capital of Lightstream consists of an unlimited number of Common Shares without nominal or par value and an unlimited number of preferred shares. As at December 31, 2014, there were 197,304,539 Common Shares and no preferred shares issued and outstanding. As at March 30, 2015, there were 197,388,248 Common Shares and no preferred shares issued and outstanding.

Holders of Common Shares are entitled to one vote per Common Share at meetings of holders of Common Shares, to receive dividends if, as and when declared by the Board with respect to the Common Shares and to receive pro rata the remaining property and assets of Lightstream upon our liquidation, dissolution or winding up, subject to the rights of shares having priority over the Common Shares.

The articles of the Company contain provisions facilitating payment of dividends on Common Shares through issuance of Common Shares in circumstances where a shareholder of the Company validly elects to receive payment of dividends, in whole or in part, in the form of Common Shares (the portion of the dividend payable in Common Shares being referred to in this paragraph as "share dividends"). In particular, the terms of Common Shares implement procedures for: (i) a shareholder of the Company to elect to accept share dividends; (ii) determining the value and number of Common Shares to be distributed by way of a share dividend; (iii) accounting for the entitlement of shareholders of the Company to fractional Common Shares resulting from share dividends; (iv) authorizing the sale of Common Shares issued in respect of share dividends to satisfy tax withholding obligations or to comply with foreign laws or regulations applicable to a shareholder of the Company, if required; and (v) payment of cash in respect of fractional Common Shares upon a person ceasing to be a registered shareholder of the Company. The Company does not currently have a share dividend plan or a dividend reinvestment plan in place.

Preferred shares may at any time and from time to time be issued in one or more series. The Board may from time to time before the issue thereof fix the number of shares in, and determine the designation, rights, privileges, restrictions and conditions attaching to the shares of, each series of preferred shares. The preferred shares shall be entitled to priority over the Common Shares and all other shares ranking junior to the preferred shares with respect to the payment of dividends and the distribution of assets of Lightstream in the event of any liquidation, dissolution or winding up of Lightstream or other distribution of assets of Lightstream among our shareholders for the purpose of winding up our affairs. The preferred shares of each series shall rank on a parity with the preferred shares of every other series with respect to priority in the payment of dividends and in the distribution of assets of Lightstream in the event of any liquidation, dissolution or winding up of Lightstream or other distribution of assets of Lightstream among our shareholders for the purpose of winding up our affairs.

Shareholder Rights Plan

Effective January 1, 2013, Lightstream adopted the Shareholder Rights Plan, which was approved by the shareholders concurrently with their approval of the Petrobank Reorganization on December 17, 2012. The Shareholder Rights Plan must next be renewed and approved by the Company's Independent Shareholders (as defined in the Shareholder Rights Plan) at the annual meeting to be held in 2015, failing which it will expire at such time. The Shareholder Rights Plan, under which Computershare acts as rights agent, generally provides that, following the acquisition by any person or entity of 20% or more of the issued and outstanding Common Shares (except pursuant to certain permitted or excepted transactions) and upon the occurrence of certain other events, each holder of Common Shares, other than such acquiring person or entity, shall be entitled to acquire Common Shares at a discounted price. The Shareholder Rights Plan is similar to other shareholder rights plans adopted by companies in the energy industry. A copy of the Shareholder Rights Plan was filed on March 31, 2015 as a "Security Holder Document' on the Company's SEDAR profile at www.sedar.com.

Senior Notes

At December 31, 2014, Lightstream had Senior Notes outstanding having an aggregate principal amount of US$800 million. The Senior Notes have an 8.625% coupon rate, paid semi-annually, and mature in February 2020. The Senior Notes are issued pursuant to the Note Indenture, which contains restrictive covenants regarding distributions, dividends, share repurchases, asset sales and incurrence of debt, as well as customary provisions with respect to change of control, redemption and events of default. The Note Indenture was filed on February 3, 2012 as a "Security Holders Document" on our SEDAR profile at www.sedar.com.

Convertible Notes

As of the date hereof, Lightstream has US$4.5 million Convertible Notes outstanding which mature in February 2016. The Convertible Notes are convertible into Common Shares with an annual interest rate of 3.125% and an initial conversion price of US$39.61 per Common Share. The conversion price is subject to adjustment upon the occurrence of certain events, including the payment of dividends on the Common Shares, and was US$26.7890 per Common Share as at December 31, 2014.

CREDIT RATINGS

The following table outlines the current ratings of the Company and our Senior Notes.

	Standard & Poor's Ratings Services ("S&P")	Moody's Investors Service ("Moody's")
Company Rating	B	B3
Outlook	Negative	Negative
Senior Notes Rating	CCC+	Caa2

In January 2015, S&P and Moody's lowered our long-term corporate credit rating to B from B+ and to B3 from B2, respectively, and the issue-level rating on our senior unsecured notes to CCC+ from B- and to Caa2 from Caa1, respectively. The ratings outlooks were also changed to negative from stable.

A credit rating generally provides an indication of the risk that the borrower will not fulfill its full obligations in a timely manner with respect to both interest and principal commitments.

S&P's credit ratings are on a rating scale that ranges from AAA to D, which represents the range from highest to lowest quality of such securities rated. S&P has assigned Lightstream a corporate credit rating of B, negative outlook, and a credit rating of CCC+ on the Senior Notes. According to S&P's rating system, a credit rating of B by S&P is within the sixth highest of ten categories and indicates more vulnerability to adverse business, financial and economic conditions, but currently has the capacity to meet financial commitments. The ratings from AA to CCC may be modified by the addition of a plus (+) or a minus (-) sign to show relative standing within the major rating categories. In addition, S&P may add a rating outlook of "positive", "negative" or "stable" which is an opinion regarding the potential direction of a long-term credit rating over the intermediate term (typically six months to two years).

Moody's credit ratings are on a rating scale that ranges from Aaa to C, which represents the range from highest to lowest quality of such securities rated. Moody's has assigned Lightstream a corporate family credit rating of B3, negative outlook, and a credit rating of Caa2 on the Senior Notes. According to Moody's rating system, securities rated "B" are within the sixth highest of nine categories and are considered speculative and are subject to high credit risk and securities rated "Caa2" are within the seventh of nine categories and are judged to be speculative of poor standing and are subject to very high credit risk. Moody's appends numerical modifiers 1, 2 and 3 to each generic rating classification from Aa through C. The modifier 1 indicates that the security ranks in the higher end of its generic rating category, the modifier 2 indicates a mid-range ranking and the modifier 3 indicates a ranking in the lower end of its generic rating category. In addition, Moody's may add a rating outlook of "positive", "negative" or "stable", which is an opinion regarding the likely direction of an issuer's rating over the medium term.

The credit ratings accorded by S&P and Moody's are not recommendations to purchase, hold or sell securities and such ratings do not comment as to market price or suitability for a particular investor. There is no assurance that any rating will remain in effect for any given period of time or that any rating will not be revised or withdrawn entirely by a rating agency in the future if in its judgment circumstances so warrant.

The Company has paid each of S&P and Moody's their customary fees in connection with the provision of the above credit ratings. The Company has not made any payments to S&P and Moody's unrelated to the provision of such ratings.

DIVIDENDS

Lightstream's policy is to use any excess cash generated from operations to pay monthly dividends to shareholders, as well as to retain a portion of cash flow to fund new and ongoing development and optimization projects. The amount of cash dividends to be paid on the Common Shares, if any, is subject to the discretion of the Board and may vary depending on a variety of factors, including fluctuations in commodity prices, production levels, capital expenditure requirements, debt service requirements, operating costs, foreign exchange rates, the satisfaction of the liquidity and solvency tests imposed by the ABCA for the declaration and payment of dividends and compliance with the agreements governing the Company's credit facility and Senior Notes. In January 2015, in response to the continued low WTI oil prices, we announced the suspension of our dividend program.

The following table sets forth the amount of monthly cash dividends paid per Common Share by the Corporation for the periods indicated.

Period	Dividend per Common Share
January 2012 – December 2012	$0.08
January 2013 – November 2013	$0.08
December 2013 – November 2014	$0.04
December 2014	$0.015
January 2015 – February 2015	--

MARKET FOR SECURITIES

Lightstream's Common Shares are listed for trading through the facilities of the TSX under the trading symbol "LTS". The table below sets forth the reported high and low monthly sales prices and the trading volumes of the Common Shares on the TSX during 2014.

	Price Range ($)		Monthly
Month	High	Low	Volume
January	6.26	5.77	16,342,110
February	6.52	5.88	10,453,561
March	6.31	5.20	18,636,072
April	6.89	5.56	15,079,489
May	7.93	6.48	18,060,287
June	9.09	7.65	16,325,866
July	8.57	7.09	15,149,864
August	7.20	5.90	13,166,914
September	6.42	5.11	21,618,922
October	5.25	2.50	34,745,112
November	3.93	2.28	40,342,072
December	2.62	1.12	55,076,993

DIRECTORS AND OFFICERS

The name, municipality of residence, position and principal occupation of each of the directors and senior officers of Lightstream, as of the date of this Annual Information Form, are as follows:

Name and Municipality of Residence	Positions Held[6]	Principal Occupation During Last Five Years
Annie Belecki Alberta, Canada	General Counsel	General Counsel of Lightstream since June 2014. Prior thereto, Associate General Counsel and Senior Legal Counsel at TransCanada Corporation (energy company) from September 2006 to June 2014 and Corporate Secretary of its U.S. affiliate, TC Pipelines L.P. from April 2012 to June 2014.
Ian S. Brown[1][4] Alberta, Canada	Director	Independent businessman and corporate director.
Mary Bulmer, Alberta, Canada	Vice President, Corporate Services	Vice President, Corporate Services of Lightstream since May 2010 and Vice President, Human Resources from October 2009 to April 2010.
Lawrence Fisher Alberta, Canada	Vice President, Land	Vice President, Land since May 2010. Prior thereto, Manager, Land Negotiations at Lightstream from October 2009 to April 2010, and Manager, Land Negotiations at TriStar Oil & Gas Ltd. from March 2008 to September 2009.

Name and Municipality of Residence	Positions Held[6]	Principal Occupation During Last Five Years
Lars Glemser Alberta, Canada	Treasurer	Treasurer of Lightstream since January 2013. Prior thereto, Manager, Financial Reporting at Lightstream from January 2011 to January 2013 and Supervisor Financial Reporting at Lightstream from October 2009 to January 2011.
Andrea Hatzinikolas Alberta, Canada	Corporate Secretary	Vice President, Legal and Corporate of Alvopetro Energy Ltd. (energy company). Prior thereto, Vice President, Business Development, General Counsel and Corporate Secretary of Petrominerales Ltd. (energy company) from May 2011 to November 2013 and Assistant Corporate Secretary and General Counsel of Petrobank (energy company) from February 2007 to May 2011.
Peter Hawkes Alberta, Canada	Vice President, Geosciences	Vice President, Geosciences of Lightstream since September 2012. Prior thereto, Vice President, Exploration of Lightstream from October 2009 to September 2012.
Martin Hislop[1][3][4] Alberta, Canada	Director	Independent businessman and corporate director.
Rene LaPrade, Alberta, Canada	Senior Vice President and Chief Operating Officer	Senior Vice President and Chief Operating Officer of Lightstream since January 2013. Prior thereto, Senior Vice President, Operations of Lightstream from September 2009 to December 2012.
E. Craig Lothian[3] Saskatchewan, Canada	Director	President and Chief Executive Officer of Keystone Royalty Corp., Lex Capital Corp. and Lex Capital Management Inc., and Executive Chair of Villanova 4 Oil Corp. (private holding, equity fund management and energy companies).
Brad Malley Alberta, Canada	Vice President, Development Services	Vice President, Development Services since February 2015 and Vice President, Drilling and Completions of Lightstream from January 2013 to February 2015. Prior thereto, General Manager of Drilling and Completions of Lightstream from December 2010 to December 2012.
Kenneth R. McKinnon[1][3][5] Alberta, Canada	Director	Vice President Legal and General Counsel of Critical Mass Inc. (website design company) since March 2000.

Name and Municipality of Residence	Positions Held[6]	Principal Occupation During Last Five Years
Corey C. Ruttan Alberta, Canada	Director	President and Chief Executive Officer of Alvopetro Energy Ltd. (energy company) since November 2013. Prior thereto, President and Chief Executive Officer of Petrominerales Ltd. (energy company) from May 2010 to November 2013. Prior thereto, Executive Vice President and Chief Financial Officer of Lightstream from July 2009 to May 2010, Senior Vice President, Finance and Chief Financial Officer of Petrobank (energy company) from November 2008 to May 2010, and Vice President, Finance and Chief Financial Officer of Petrominerales Ltd. from May 2006 to May 2010.
Doreen M. Scheidt Alberta, Canada	Vice President and Controller	Vice President and Controller of Lightstream since January 2013 and Controller of Lightstream from October 2009 to December 2012.
Peter D. Scott Alberta, Canada	Senior Vice President and Chief Financial Officer	Senior Vice President and Chief Financial Officer of Lightstream since May 2010. Prior thereto, Vice President, Finance of Lightstream from January 2010 to May 2010. Prior thereto, Vice President, Finance and Chief Financial Officer of Iteration Energy Ltd. (energy company) from March 2009 to January 2010.
Dan Themig[2][4] Alberta, Canada	Director	President of Packers Plus Energy Services Inc. since September 2002.
W. Brett Wilson[2] Alberta, Canada	Director	Chairman of Canoe 'GO CANADA' Fund Corp. (mutual fund corporation) since July 2013 and Chairman of Prairie Merchant Corporation (private investment management company) since 1991.
John D. Wright[2] Alberta, Canada	Director, President and Chief Executive Officer	President and Chief Executive Officer of Lightstream since May 2011. Prior thereto, President and Chief Executive Officer, Chairman, and director of Petrobank from March 2000 to May 2014 and President and Chief Executive Officer of Petrominerales Ltd. from May 2006 to May 2010.

Notes:

1. Member of the Audit Committee.
2. Member of the Reserves Committee.
3. Member of the Compensation Committee.
4. Member of the Nominating Committee.
5. Chairman of the Board of Directors
6. The term of office of each director expires at the next annual meeting of shareholders.

As at March 30, 2015, the directors and executive officers of Lightstream, as a group, beneficially owned or exercised control or direction over 9,453,493 Common Shares constituting approximately 4.8% of the issued and outstanding Common Shares.

CEASE TRADE ORDERS, BANKRUPTCIES, PENALTIES OR SANCTIONS

Except as disclosed herein, to the knowledge of the Company:

(a) no director or executive officer of the Company is as at the date hereof or was within the 10 years prior to the date hereof, a director, chief executive officer or chief financial officer of any company (including Lightstream) that was subject to a cease trade order or similar order or an order that denied the relevant company access to any exemption under securities legislation that was in effect for a period of more than 30 consecutive days and (i) was issued while the director or executive officer was acting in the capacity as director, chief executive officer or chief financial officer, or (ii) was issued after the director or executive officer ceased to be a director, chief executive officer or chief financial officer and resulted from an event that occurred while that person was acting in the capacity as director, chief executive officer or chief financial officer;

(b) no director or executive officer of the Company and no security holder holding a sufficient number of securities of the Company to affect materially the control of the Company, has been subject to (i) any penalties or sanctions imposed by a court relating to securities legislation or by a securities regulatory authority or has entered into a settlement agreement with a securities regulatory authority, or (ii) any other penalties or sanctions imposed by a court or regulatory body that would likely be considered important to a reasonable investor in making an investment decision;

(c) no director or executive officer of the Company and no security holder holding a sufficient number of securities of the Company to affect materially the control of the Company is or has been within the 10 years preceding the date hereof, a director or executive officer of any company, that while that person was acting in that capacity, or within a year of that person ceasing to act in that capacity, became bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets; and

(d) in addition, no director or executive officer or securityholder holding a sufficient number of securities of the Company to affect materially the control of the Company has, within the last 10 years prior to the date hereof, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or become subject to or instituted any proceedings, arrangement or compromise with creditors, or had a receiver, receiver manager or trustee appointed to hold the assets of the director, executive officer or securityholder.

Rene LaPrade

On April 30, 2008, a management cease trade order ("**MCTO**") was issued by the Alberta Securities Commission ("**ASC**") in respect of Sahara Energy Ltd. ("**Sahara**"), a reporting issuer listed on the TSX Venture Exchange. The MCTO was issued against Sahara for failure to file annual audited financial statements for the year ended December 31, 2007 (the "**Unfiled Statements**"). The MCTO prohibited certain directors and officers of Sahara, including Mr. Rene LaPrade (a director of Sahara), from trading in securities of Sahara until two business days following the filing of the Unfiled Statements with the ASC or until the MCTO was revoked. The MCTO expired on June 17, 2008.

On January 8, 2009, Mr. Rene LaPrade entered into a settlement agreement with the ASC in respect of an insider trading violation relating to a February 6, 2008 trade. Mr. LaPrade cooperated fully with the ASC in resolving the matter. Mr. LaPrade paid $10,000 in settlement of the allegations against him and costs of the investigation in the amount of $500. As part of the settlement agreement, until January 8, 2010, Mr. LaPrade agreed to cease trading in securities (subject to certain exceptions) and to refrain from acting as a director of any issuer.

Corey C. Ruttan

Mr. Corey C. Ruttan entered into a settlement agreement with the ASC on May 3, 2002 in respect of an insider trading violation relating to a May 17, 2000 trade. Mr. Ruttan cooperated completely in resolving the matter with the regulators. The settlement resulted in Mr. Ruttan paying an administrative penalty of $10,000, representing a return of profits, and the costs of the proceeding in the amount of $3,925. For a period of one year, Mr. Ruttan agreed to cease trading in securities and to not act as a director or officer of a public company. These restrictions expired on May 3, 2003. Mr. Ruttan is a Chartered Accountant in good standing.

John D. Wright

Mr. John D. Wright was a director of Canadian Energy Exploration Inc. ("**CEE**") (formerly TALON International Energy, Ltd.), a reporting issuer listed on the TSX Venture Exchange, until September 15, 2011. A cease trade order (the "**ASC Order**") was issued on May 7, 2008 against CEE by the ASC for the delayed filing of CEE's audited annual financial statements and management's discussion and analysis for the year ended December 31, 2007 ("**2007 Annual Filings**"). The 2007 Annual Filings were filed by CEE on SEDAR on May 8, 2008. As a result of the ASC Order, the TSX Venture Exchange suspended trading in CEE's shares on May 7, 2008. In addition, on June 4, 2009 the British Columbia Securities Commission ("**BCSC**") issued a cease trade order (the "**BCSC Order**") against CEE for the failure of CEE to file its audited annual financial statements and management's discussion and analysis for the year ended December 31, 2008 (the "**2008 Annual Filings**") and its unaudited interim financial statements and management's discussion and analysis for the three months ended March 31, 2009 (the "**2009 Interim Filings**"). The 2008 Annual Filings and the 2009 Interim Filings were filed by CEE on SEDAR on October 9, 2009.

CEE made application to the ASC and BCSC for revocation of the ASC Order and BCSC Order. The ASC and BCSC issued revocation orders dated October 14, 2009 and November 30, 2009, respectively, granting full revocation of compliance-related cease trade orders issued by the ASC and the BCSC in respect of CEE.

INDUSTRY CONDITIONS

Companies operating in the oil and natural gas industry are subject to extensive control and regulation governing their operations, including land tenure, exploration, development, production, marketing, transportation, and refining, through legislation enacted by various levels of government. In addition, pricing and taxation of oil and natural gas are governed by agreements among the governments of Canada, British Columbia, Alberta and Saskatchewan. It is not expected that any of these controls or regulations will affect the operations of Lightstream in a manner materially different than they would affect other oil and gas companies of a similar size. All current legislation is a matter of public record and Lightstream is unable to predict what additional legislation or amendments may be enacted. Outlined below are some of the principal aspects of legislation, regulations and agreements governing the oil and gas industry.

Land Tenure

Crude oil and natural gas located in British Columbia, Alberta and Saskatchewan are owned predominantly by the respective provincial governments, generally termed the "Crown". Provincial governments grant rights to explore for and produce oil and natural gas under leases, licenses and permits with terms generally varying from two years to five years and on conditions contained in provincial legislation. Leases, licenses and permits may be continued indefinitely by producing under the lease, license or permit. Some of the oil and natural gas located in these provinces is freehold (privately owned) and rights to explore for and produce oil and natural gas are granted by the respective mineral owners on negotiated terms and conditions on a lease-by-lease basis.

Pricing and Marketing – Crude Oil

In Canada, producers of oil negotiate sales contracts directly with oil purchasers, with the result that the market determines the price of oil. Worldwide supply and demand factors primarily determine oil prices, however, prices are also influenced by regional market and transportation issues. The price depends in part on world market forces (OPEC, and hostilities in the middle east and other regions around the world) the oil type, oil quality, prices of competing oil types, distance to market, availability and cost of transportation capacity to various markets, the value of refined products and the supply/demand balance. Oil exports may be made pursuant to export contracts with terms not exceeding one year in the case of crude oil other than heavy crude oil, and not exceeding two years in the case of heavy crude oil, provided that an order approving any such export has been obtained from the National Energy Board ("**NEB**"). Any crude oil export to be made pursuant to a contract of longer duration (to a maximum of 25 years) requires an exporter to obtain an export license from the NEB and the issue of such a license requires the approval of the Governor in Council.

Pricing and Marketing – Natural Gas

In Canada, natural gas is sold throughout the country and in the United States at various market hubs, which are connected to pipelines within Canada and the United States. The transaction price is determined by negotiation between natural gas producers, marketers and purchasers, and includes the utilization of electronic trading platforms, various publications and reference indices. Prices depend on many variables including but not limited to supply and demand fundamentals, the price of New York Mercantile Exchange natural gas contracts, distance to alternate markets, pipeline transportation costs, natural gas storage levels, competing fuels, contract terms, weather, and foreign currency exchange. Natural gas exported from Canada is subject to regulation by the NEB and the Government of Canada. Exporters can negotiate prices and other terms with purchasers, provided that the export contracts must continue to meet certain criteria prescribed by the NEB and the Government of Canada. As in the case with oil, natural gas exported from Canada for a term of two years or less or for a term of between two and 20 years (in quantities of not more than 30,000 10^3m^3 per day) may be made pursuant to a NEB order, or, in the case of exports for a longer duration (to a maximum of 25 years) or a larger quantity, pursuant to an NEB export license and Governor in Council approval.

The governments of British Columbia, Alberta and Saskatchewan regulate the volume of natural gas that may be removed from those provinces based on such factors as reserve availability, transportation arrangements and market considerations.

Royalties and Incentives

General

In addition to federal regulation, each province has legislation and regulations which govern land tenure, royalties, production rates, environmental protection and other matters. In all provincial jurisdictions where we operate, producers of oil and natural gas are required to pay annual rental payments in respect of Crown leases and royalties and freehold production taxes in respect of oil and natural gas produced from Crown and freehold lands, respectively. The royalty regime in a given province is a significant factor in the profitability of crude oil and natural gas production. Royalties payable on production from lands, other than Crown lands, are determined by negotiations between the mineral freehold owner and the lessee, although production from such lands is also subject to certain provincial taxes and royalties. Crown royalties are determined by governmental regulation and are generally calculated as a percentage of the value of gross production and the rate of royalties payable generally depends in part on prescribed reference prices, well productivity, geographical location, field discovery date, method of recovery and the type or quality of the petroleum product produced. Other royalties and royalty-like interests are, from time to time, carved out of the working interest owner's interest through non-public transactions. These are often referred to as overriding royalties, gross overriding royalties, net profits interests or net carried interests.

From time to time, the governments of Canada, British Columbia, Alberta and Saskatchewan have established incentive programs which have included royalty rate reductions, royalty holidays or tax credits for the purpose of encouraging oil and natural gas exploration or enhanced planning projects. Such programs are generally introduced when commodity prices are low, and are designed to encourage exploration and development activity by improving project economics. These programs reduce the amount of Crown royalties otherwise payable.

Alberta

Producers of oil and gas from Crown lands in Alberta are required to pay annual rental payments, currently at a rate of $3.50 per hectare, and make monthly royalty payments in respect of oil and natural gas produced.

Royalties are currently paid pursuant to "The New Royalty Framework" (implemented by the Mines and Minerals (New Royalty Framework) Amendment Act, 2008) and the "Alberta Royalty Framework", which was implemented in 2010.

Royalty rates for conventional oil are set by a single sliding rate formula, which is applied monthly and incorporates separate variables to account for production rates and market prices. The maximum royalty payable under the royalty regime is 40 percent. Royalty rates for natural gas under the royalty regime are similarly determined using a single sliding rate formula with the maximum royalty payable under the royalty regime set at 36 percent.

Producers of oil and natural gas from freehold lands in Alberta are required to pay freehold production tax. The freehold production tax is a tax levied by the Government of Alberta on the value of oil and natural gas production from non-Crown lands and is derived from the *Freehold Mineral Rights Tax Act* (Alberta). The freehold mineral tax is levied on an annual basis on calendar year production using a tax formula that takes into consideration, among other things, the amount of production, the hours of production, the value of each unit of production, the tax rate and the percentages that the owners hold in the title. On average, the tax levied is four percent of revenues reported from fee simple mineral title properties.

The Government of Alberta has from time to time implemented drilling credits, incentives or transitional royalty programs to encourage oil and gas development and new drilling. For example, the Innovative Energy Technologies Program (the "IETP"), which is currently in place, has the stated objectives of increasing recovery from oil and gas deposits, finding technical solutions to the gas over bitumen issue, improving the recovery of bitumen by in-situ and mining techniques and improving the recovery of natural gas from coal seams. The IETP provides royalty adjustments to specific pilot and demonstration projects that utilize new or innovative technologies to increase recovery from existing reserves.

In addition, the Government of Alberta has implemented certain initiatives intended to accelerate technological development and facilitate the development of unconventional resources (the "Emerging Resource and Technologies Initiative"). Specifically:

- Coalbed methane wells will receive a maximum royalty rate of five percent for 36 producing months on up to 750 MMcf of production, retroactive to wells that began producing on or after May 1, 2010;

- Shale gas wells will receive a maximum royalty rate of five percent for 36 producing months with no limitation on production volume, retroactive to wells that began producing on or after May 1, 2010;

- Horizontal gas wells will receive a maximum royalty rate of five percent for 18 producing months on up to 500 MMcf of production, retroactive to wells that commenced drilling on or after May 1, 2010; and

- Horizontal oil wells and horizontal non-project oil sands wells will receive a maximum royalty rate of five percent with volume and production month limits set according to the depth of the well (including the horizontal distance), retroactive to wells that commenced drilling on or after May 1, 2010.

Saskatchewan

In Saskatchewan, crude oil Crown royalties and freehold production tax depend on well productivity, the current market price of oil, the classification and vintage of the oil and the quantity of oil produced in a month. Crude oil is classified as "heavy oil", "southwest designated oil" or "non-heavy oil other than southwest designated oil", and the vintage classifications ("fourth tier oil", "third tier oil", "new oil" or "old oil") are applicable to each of these three crude oil types. Generally, the vintage of oil is based on the determination of whether the well was on production before January 1, 1974 ("old oil"), drilled between February 9, 1998 and October 1, 2002 ("new oil"), between January 1, 1974 (April 1, 1991 if horizontal) and January 1, 1994 (October 1, 2002 if horizontal) ("third tier oil"), or after October 1, 2002 ("fourth tier oil"). Newly drilled oil wells in Saskatchewan qualify for "volume based" incentives ranging from 0 to 16,000 m3, depending on the type of well (deep or non-deep, exploratory or development, and horizontal or vertical). Qualifying incentive volumes are subject to a maximum royalty rate of 2.5% and a freehold production tax rate of 0%.

Saskatchewan Crown royalties and freehold production tax on natural gas are price sensitive, depending also on the vintage of the natural gas, the quantity produced in a month, and whether the gas is associated (gas produced from oil wells) or non-associated. The vintage classifications of gas production are "fourth tier gas", "third tier gas", "new gas" and "old gas". Generally, the vintage of gas is based on the determination of whether the gas is produced from a well on production before October 1, 1976 ("old gas"), drilled between October 1, 1976 and February 9, 1998 ("new gas"), between February 9, 1998 and October 1, 2002 (third tier gas), or after October 1, 2002 ("fourth tier gas"). Newly drilled qualifying exploratory gas wells in Saskatchewan qualify for a 25,000,000 m3 "volume based" incentive. The qualifying incentive volume is subject to a maximum Crown royalty rate of 2.5% and a freehold production tax rate of 0%.

The majority of Lightstream's production in Saskatchewan is "non-heavy oil other than southwest designated oil" with a vintage classification of "fourth tier oil". Saskatchewan royalty payable on this production is 2.5% until 6,000 m3 (37,740 barrels) of oil have been produced. Production in excess of this threshold is subject to a royalty rate based on well productivity and oil prices. The maximum royalty rate for all fourth tier oil is 30%.

The majority of Lightstream's gas production in Saskatchewan is "associated gas" which is natural gas produced in association with oil. As an incentive for the production and marketing of natural gas which could otherwise have been flared, the royalty rate for associated gas is less than on non-associated natural gas. The maximum royalty rate for all fourth tier gas is 30%.

British Columbia

Producers of oil and natural gas in British Columbia are required to pay royalties and freehold production taxes in respect of oil and gas produced from Crown and freehold lands, respectively. The amount payable as a royalty in respect of oil depends on the vintage of the oil pool discovery (whether the oil was produced from a pool discovered before or after October 31, 1975), whether the oil is considered incremental or produced from a well shut-in for at least 36 months immediately preceding January 1, 1998 and which resumed production on or after such date, the quantity of oil produced in a month and the value of the oil. Oil produced from pools discovered after June 30, 1974 may be exempt from the payment of a royalty for the first 36 months of production. Subject to minimum royalties described in the following sentence, the royalty payable on natural gas is determined by a sliding scale based on a reference price which is the greater of the amount obtained by the producer and at prescribed minimum price. Gas produced in association with oil has a minimum royalty of 8%, while the royalty in respect of other gas may not be less than 15%.

British Columbia Crown natural gas basic royalty with respect to gas typical of new drilling prospects, ranges from 9% to 27%, based on gas price. Low productivity wells, marginal wells and ultra marginal wells will have their royalties reduced and will approach 0% as the production rate approaches zero. During 2008, the Deep Well Program was extended, which provides royalty credits for wells with vertical depths greater than 2,500 meters, or for horizontal wells with completion point vertical depth greater than 2,300 meters. Royalty credit ranges from zero at 2,500 meters to $2.7 million at a depth of 5,500 meters for wells located in the east map area of northeast British Columbia, where we own significant mineral rights.

Environmental Regulation

All phases of the oil and natural gas business present environmental risks and hazards and are subject to "cradle to grave" environmental regulation pursuant to international conventions and national, provincial, and municipal laws and regulations. Environmental legislation governs all aspects and phases of oil and gas development, from planning and construction, through operations and onto final abandonment and reclamation. All jurisdictions have restrictions and prohibitions for spills, releases, discharges, or emissions of various substances produced or used in association with oil and natural gas operations, as well as requirements for oilfield waste handling and storage, habitat protection, and setbacks of oil and natural gas activities from fresh water bodies, buildings and urban centers.

Environmental legislation also requires wells and facility sites to be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. Compliance with such legislation can require significant expenditures and a breach may result in the imposition of significant fines and penalties (including imprisonment) or in the suspension or revocation of necessary licenses and approvals. Lightstream may also be subject to civil liability for damage caused by pollution. Certain environmental protection legislation may subject us to statutory strict liability in the event of an accidental spill or discharge from a licensed facility, meaning that fault on our part need not be established if such a spill or discharge is found to have occurred.

Environmental legislation in the Province of Alberta is, for the most part, set out in the Environmental Protection and Enhancement Act and the Oil and Gas Conservation Act. This legislation enables numerous regulations, guidelines and codes of practice, which impose strict environmental standards relating to the release of substances and the protection of species, habitat and land capability in the province and include monitoring and reporting obligations that carry significant penalties for non-compliance. On June 17, 2013, Alberta introduced the Responsible Energy Development Act, under which the new Alberta Energy Regulator ("**AER**") superseded the Energy Resources Conservation Board ("**ERCB**") as the provincial energy regulator. The AER is responsible for the administration of both the Environmental Protection and Enhancement Act and the Oil and Gas Conservation Act.

Environmental legislation in the Province of Saskatchewan is, for the most part, set out in the Environmental Management and Protection Act, 2002 and the Oil and Gas Conservation Act, which regulate harmful or potentially harmful activities and substances, any release of such substances and remediation obligations. Certain development activities in Saskatchewan, depending on the location and potential environmental impact, may require a screening or an environmental impact assessment under the provincial Environmental Assessment Act. With implementation anticipated shortly, Saskatchewan is currently working towards a new legal framework, the Saskatchewan Environmental Code, which aims to address specific activities and standards under current environmental legislation as well as introduce new regulations for the management of greenhouse gases.

Environmental legislation in the Province of British Columbia is, for the most part, set out in the Environmental Management Act (the "**EMA**"), the Oil and Gas Activities Act and the Petroleum and Natural Gas Act, which regulate the storage, discharge and disposal of air contaminants, effluent and hazardous waste into the environment. Specifically, the Oil and Gas Waste Regulation under the EMA regulates hydrogen sulphide and nitrogen oxide emissions from oil and natural gas facilities. The EMA provides for the imposition of significant penalties in the event of non-compliance with regulations and standards and sets the criteria for the remediation of contaminated sites. New oil and natural gas projects, or modifications to existing projects, may be subject to a review under the Environmental Assessment Act.

Greenhouse Gases and Industrial Air Pollutants

Canada

The Government of Canada previously released the Regulatory Framework for Air Emissions, updated March 10, 2008 by Turning the Corner: Regulatory Framework for Industrial Greenhouse Gas Emissions (collectively, the "**Regulatory Framework**"), for regulating GHG emissions by proposing mandatory emissions intensity reduction obligations on a sector by sector basis. Legislation to implement the Regulatory Framework had been expected to be put in place, but the federal government has delayed the release of any such legislation and potential federal requirements in respect of GHG emissions are unclear. In 2009, the Government of Canada announced its commitment to work with the provincial governments to implement a North American-wide 'cap and trade' system for GHG emissions, in cooperation with the United States. On January 30, 2010, the Government of Canada announced its new target to reduce overall Canadian GHG emissions by 17% below 2005 levels by 2020, from the previous target of 20% below 2006 levels by 2020, and to align itself with U.S. policy. In December of 2011, the Government of Canada indicated that it would not agree to a second commitment period under the Kyoto Protocol and provided its support for a new climate change treaty to be negotiated pursuant to the provisions of the Durban Platform. It is currently unclear when any such treaty will be finalized, when the Government of Canada will introduce regulations pertaining to the GHG emissions or what any such treaties or regulations will involve.

The Government of Canada currently proposes to enter into equivalency agreements with provinces to establish a consistent regulatory regime for GHGs, but the success of any such plan is uncertain, possibly leaving overlapping levels of regulation. It is uncertain whether either federal GHG regulations or an integrated North American 'cap and trade' system will or will not be implemented or what obligations might be imposed under any such system. As the details of the implementation of any federal legislation for GHGs have not been announced, the effect on our operations cannot be determined at this time.

Alberta

Alberta currently regulates GHG emissions under the Climate Change and Emissions Management Act, the *Specified Gas Reporting Regulation* (the "**SGRR**"), which imposes GHG emissions reporting requirements, and the *Specified Gas Emitters Regulation* (the "**SGER**"), which imposes GHG emissions limits. Under the SGRR, GHG emissions of 50,000 tonnes or more from a facility in any year must be reported to Alberta Environment. The SGER applies to facilities in Alberta that have produced 100,000 or more tonnes of GHG emissions in 2003 or any subsequent year and requires reductions in GHG emissions intensity (i.e. the quantity of GHG emissions per unit of production) from emissions intensity baselines that are established in accordance with the SGER. The SGER distinguishes between "established" facilities that completed their first year of commercial operation before January 1, 2000 or have completed eight years of commercial operation, and "new" facilities that have completed their first year of commercial operation on December 31, 2000 or a subsequent year and have completed less than eight years of commercial operation. Generally, the baseline for an established facility reflects the average of emissions intensity in 2003, 2004 and 2005, and for a new facility emissions intensity in the third year of commercial operation. For an established facility, the required reduction in GHG emissions is 12% from its baseline, and such reduction must be maintained over time. For a new facility, the reduction requirement from its baseline is phased in by annual 2% increments beginning in the fourth year of commercial operation until the maximum 12% reduction requirement imposed on established facilities is reached. There are three ways to comply with reduction requirements: (i) actual physical reductions in GHG emissions intensity; (ii) purchase of Alberta-based emission offset credits and/or emission performance credits; or (iii) purchase of the Government of Alberta's Climate Change and Emissions Management Fund ("**Fund**") credits. Historically, the Fund credits have been available at a cost of \$15/tonne of GHG emissions, although they are now priced at an amount established by order of the Minister of Environment. Compliance reports for facilities subject to the SGER are due to Alberta Environment on March 31 annually. The Government of Alberta has previously announced in its 2008 Provincial Energy Strategy that it may modify the SGER towards stricter standards. In addition, Alberta facilities must currently report emissions of industrial air pollutants and comply with obligations imposed in permits and under environmental regulations. Currently, Lightstream's facilities in Alberta are not subject to reporting or reductions under the SGRR or SGER.

British Columbia

On April 3, 2008, British Columbia introduced the *Greenhouse Gas Reduction (Cap and Trade) Act* (the "**Cap and Trade Act**") which received royal assent on May 29, 2008 and partially came into force by regulation of the Lieutenant Governor in Council. It sets a province-wide target of a 33 per cent reduction in the 2007 level of GHG emissions by 2020 and an 80 per cent reduction by 2050. Unlike the emissions intensity approach taken by the federal government and the Government of Alberta, the Cap and Trade Act establishes an absolute cap on GHG emissions. The reporting regulation, implemented under the authority of the Cap and Trade Act sets out the requirements for the reporting of the GHG emissions from facilities in British Columbia emitting 10,000 tonnes or more of carbon dioxide equivalent emissions per year beginning on January 1, 2010. Those reporting operations with emissions of 25,000 tonnes or greater are required to have emissions reports verified by a third party. Emissions include flaring and carbon dioxide from natural gas fuel consumption. Lightstream currently reports under the British Columbia regulations with respect to three of our facilities and associated wells.

Saskatchewan

On May 11, 2009, the Government of Saskatchewan announced *The Management and Reduction of Greenhouse Gases Act* (the "**MRGGA**") to regulate GHG emissions in the province. The MRGGA has received royal assent but has not yet been proclaimed and so is not yet in force. It remains unclear to what degree a scheme implemented under the MRGGA will affect Lightstream.

The Future of GHG Emission Regulations

There will most certainly be a financial impact of GHG emission regulation on oil and gas industry participants and their projects. However, the extent of that impact is not yet known. In particular, there is uncertainty regarding the ultimate GHG emission regulatory regime that will be applicable to us due to a variety of factors, including the potential for changes to the regulation of GHG emissions and the potential for the harmonization of GHG emission regulatory regimes across various jurisdictions, which may impact our operations.

At present, there is no assurance that any new regulations implemented by the Government of Canada relating to the reduction of GHG emissions will be harmonized with the Government of Alberta's GHG emissions reduction regulations. In such case, the costs of meeting new federal government requirements could be considerably higher than the costs of meeting Alberta's current requirements.

Hydraulic Fracturing

The proliferation of the use of hydraulic fracturing as a recovery technique employed in natural gas drilling has given rise to increased public scrutiny of its environmental aspects, particularly with respect to its potential impact on local aquifers. Lightstream utilizes hydraulic fracturing in a significant portion of the light oil wells it drills and completes. Lightstream believes that the hydraulic fracturing that we conduct, given the depth and location of the wells and our consistent utilization of good oilfield practices, is environmentally sound in general and would not give rise to concerns raised respecting local aquifers.

Lightstream anticipates that there will be a trend towards increased regulatory requirements concerning hydraulic fracturing in the future. The Canadian Association of Petroleum Producers has announced new hydraulic fracturing operating practices designed to improve water management and water and fluids reporting for shale gas and tight gas development across Canada. Regulatory agencies in Alberta and British Columbia currently have regulations in place that require companies to disclose wells hydraulically fractured and the ingredients of hydraulic fracturing fluids.

Fugitive Gas Emissions in Saskatchewan

The Saskatchewan Ministry of the Economy enacted a Minister's Order in June of 2011 pursuant to The Oil and Gas Conservation Act requiring adherence to Directive S-10 - Saskatchewan Upstream Petroleum Industry Associated Gas Conservation Directive and Directive S-20 - Saskatchewan Upstream Flaring and Incineration Requirements (together, the "**Directives**"). Directive S-10 provides enforceable regulatory requirements for reducing flaring and venting of associated gas from upstream activity in the province and Directive S-20 provides for regulatory guidance as to gas flaring and incineration performance, equipment spacing and design and set-back requirements. The Directives were put in place to reduce fugitive emissions and ensure that upstream oil and gas facilities and wells are operated in a manner that does not result in air pollution that exceeds the ambient air quality standards prescribed by Saskatchewan Ministry of the Environment. Both Directives became effective immediately on all wells and facilities licensed on or after July 1, 2012. Existing wells and facilities licensed before July 1, 2012 were allowed a phase in period until July 1, 2015 unless valid public complaints are raised with respect to noise, odour or smoke from flares and venting and/or Minister's Order.

Trends

The operations of the Company are, and will continue to be, affected in varying degrees by laws and regulations regarding environmental protection. Lightstream believes it is likely that the trend in environmental legislation and regulation will continue toward stricter standards. It is impossible to predict the full impact of these laws and regulations on our operations. It is not anticipated that our competitive position will be adversely affected by current or future environmental laws and regulations governing our current oil and gas operations. No assurance can be given, however, that environmental or safety laws or regulations will not result in a curtailment of production, a material increase in the costs of production or development or exploration activities or otherwise adversely affect our projects, financial condition, capital expenditures, results of operations, competitive position or prospects. The Company is committed to meeting our responsibilities to protect the environment and the safety of our workers in all areas where we conduct operations and will take such steps as required to ensure compliance with environmental and safety legislation.

RISK FACTORS

The following risk factors, together with other information contained in this Annual Information Form, should be carefully considered before investing in the Company. Each of these risks may negatively affect the trading price of the Lightstream's Common Shares and the amount, if any, of dividends that may from time to time be declared and paid to shareholders. If any of the following risks actually occur, Lightstream's business, financial condition and operating results could be materially and adversely affected. Additional risks are described under the heading "*Risks and Uncertainties*" in our Management's Discussion and Analysis for the year ended December 31, 2014.

Nature of the Business

An investment in Lightstream should be considered speculative due to the nature of the Company's involvement in the exploration for, and the acquisition, development and production of, oil and natural gas in Canada. Oil and gas operations involve many risks, which even a combination of experience and knowledge and careful evaluation may not be able to overcome. There is no assurance that further commercial quantities of oil and natural gas will be discovered or acquired by the Company.

Share Price Volatility

The trading price of our Common Shares is subject to substantial volatility often based on factors related and unrelated to our financial performance or prospects. Factors unrelated to our performance could include macroeconomic developments nationally, within North America or globally, domestic and global commodity prices or current perceptions of the oil and gas market. Similarly, the market price of our Common Shares could be subject to significant fluctuations in response to variations in our operating results, financial condition, liquidity and other internal factors. Factors that could affect the market price of our Common Shares that are unrelated to our performance include domestic and global commodity prices and market perceptions of the attractiveness of particular industries. The price at which our Common Shares will trade cannot be accurately predicted.

Commodity Price Volatility

The Corporation's results of operations and financial condition are dependent on the prices it receives for the oil and natural gas it produces and sells. Oil and natural gas prices have fluctuated widely during recent years and may continue to be volatile in the future. Oil and natural gas prices have decreased significantly since mid-2014 and have fluctuated in response to a variety of factors beyond the Corporation's control, including: global energy policy, including the ability of OPEC to set and maintain production levels for oil; geo-political conditions; worldwide economic conditions including ongoing credit and liquidity concerns; weather conditions including weather-related disruptions to the North American natural gas supply; the supply and price of foreign and North American produced oil and natural gas; the level of consumer demand; the price and availability of alternative fuels; the proximity to, and capacity of, transportation facilities; the effect of worldwide energy conservation measures; and government regulation.

The prices received by Lightstream for its oil are subject to differentials against such benchmarks as WTI and Edmonton Par which can fluctuate substantially and result in Lightstream realizing prices substantially below such benchmarks. North American crude oil price differentials are expected to continue to be volatile throughout 2015 which will have an impact on crude oil prices for Canadian producers. Overall, supply in excess of current pipeline and refining capacity is expected to exist. Material structural changes are required to reduce these bottlenecks and the resulting steep price discounts. There are numerous projects proposed to alleviate pipeline bottlenecks in the United States, expand refinery capacity and expand or build new pipelines in Canada and the United States to source new markets, many of which are in the regulatory application phase. There can be no assurance that such regulatory approvals will be secured on a timely basis or at all.

Any further decline in crude oil or natural gas prices may have a material adverse effect on the Corporation's operations, financial condition, borrowing ability, levels of reserves and resources, the level of expenditures for the development of the Corporation's oil and natural gas reserves or resources and could result in further impairment test write-downs. Certain oil or natural gas wells may become or remain uneconomic to produce if commodity prices are low, thereby impacting the Corporation's production volumes, or our desire to market our production in unsatisfactory market conditions. Furthermore, the Corporation may be subject to the decisions of third party operators who may decide to curtail production. A prolonged or substantial material decline in prices from historical average prices could result in reduced credit facilities available to the Company and possibly require that a portion of the Company's bank debt be repaid.

From time to time the Company may enter into agreements to receive fixed prices on our oil and natural gas production to offset the risk of revenue losses if commodity prices decline, known as hedging, however, if commodity prices increase beyond the levels set in such agreements, the Company will not benefit from such increases and the Company may nevertheless be obligated to pay royalties on such higher prices, even though not received by us, after giving effect to such agreements. The Company could also be subject to margin requirements associated with certain hedging instruments.

<u>Financial Resources and Indebtedness</u>

The Company's cash from operations may not be sufficient to fund our ongoing activities and implement our business plans. From time to time the Company may enter into transactions to acquire assets or the shares of other companies. These transactions along with the Company's ongoing operations may be financed partially or wholly with debt, which may increase the Company's debt levels above industry standards. Our indebtedness may limit our ability to pay future dividends to shareholders, and could affect the market price of the Common Shares. The agreements governing our credit facility and Senior Notes provide that if we are in default under the credit facility or Senior Notes or fail to comply with certain covenants, we must repay the indebtedness at an accelerated rate, and the ability to make payment of dividends to shareholders may be restricted. If we are unable to pay the debt service charges or otherwise commit an event of default, such as bankruptcy, our lenders may receive a judgment and have a claim on our properties. The proceeds of any sale of properties would be applied to satisfy amounts owed to the creditors. Only after the proceeds of that sale were applied towards the debt would the remainder, if any, be available for distribution to shareholders.

Depending on future exploration and development plans, the Company may require additional financing, which may not be available or, if available, may not be available on favourable terms. Failure to obtain such financing on a timely basis could cause the Company to forfeit or forego various opportunities. Credit markets throughout the world may be restrictive, which could limit the Company's ability to access incremental debt. As at December 31, 2014, the Company had positive funds flows from operations and a credit facility with approximately $572 million of available capacity. In addition, as of the date hereof, Lightstream has Senior Notes outstanding having an aggregate principal amount of US$800 million, which mature February 2020 and Convertible Notes outstanding having an aggregate principal amount of US$4.5 million, which mature February 2016.

The interest rate payable by Lightstream under our credit facility is not fixed. Any increase in interest rates would increase the amount that Lightstream pays to service our debt and a significant increase in interest rates may materially adversely affect Lightstream's financial results.

<u>Reserves</u>

The Company's future reserves and production and, therefore, cash flows are highly dependent upon success in exploiting the Company's current reserves base and acquiring or discovering additional reserves. Without reserves additions through exploration, acquisition or development activities, Lightstream's reserves and production will decline over time. Exploring for, developing or acquiring reserves is capital intensive. To the extent cash from operations are insufficient to fund the Company's capital expenditures and external sources of capital become limited or unavailable, Lightstream's ability to make the necessary capital investments to maintain oil and natural gas reserves will be impaired. Costs to find and develop or acquire additional reserves also depend on success rates, which vary over time. Without reserve additions, our reserves will deplete and as a consequence, either production from, or the average reserve life of, our properties will decline. Either decline may result in a reduction in the value of the Common Shares and in a reduction in cash available for dividends to shareholders.

<u>Seasonality</u>

The level of activity in the Canadian oil and gas industry is influenced by seasonal weather patterns. Wet weather and spring thaw may make the ground unstable. Consequently, municipalities and provincial transportation departments enforce road bans that restrict the movement of rigs and other heavy equipment, thereby reducing activity levels. Also, certain oil and gas producing areas are located in areas that are inaccessible other than during the winter months because the ground surrounding the sites in these areas consists of swampy terrain. Reduced activity levels caused by weather related issues may cause us to shut-in producing wells and to delay the drilling and completion of wells and the construction of facilities which could reduce production levels, and cash flows, therefore negatively impacting our share price and ability to pay future dividends.

<u>Strong Competition</u>

The oil and natural gas industry is intensely competitive. Competition is particularly intense in the acquisition of prospective oil and natural gas properties and oil and gas reserves. Lightstream's competitive position depends on our geological, geophysical and engineering expertise, our financial resources, our ability to develop our properties and our ability to select, acquire and develop our reserves. Lightstream competes with a substantial number of other companies having larger technical staffs and greater financial and operational resources. Many such companies not only engage in the acquisition, exploration, development and production of oil and natural gas reserves, but also carry on refining operations and market refined products. Lightstream also competes with major and independent oil and natural gas companies and other industries supplying energy and fuel in the marketing and sale of oil and natural gas to transporters, distributors and end users, including industrial, commercial and individual consumers. Lightstream also competes with other oil and natural gas companies in attempting to secure drilling rigs and other equipment necessary for drilling and completion of wells. Such equipment may be in short supply from time to time. In addition, equipment and other materials necessary to construct production and transmission facilities may be in short supply from time to time. Finally, companies not previously investing in oil and natural gas may choose to acquire reserves to establish a firm supply or simply as an investment. Such companies also provide competition for Lightstream.

Oil and Natural Gas Production and Ultimate Reserves Could Vary Significantly From Reported Reserves

The Company's reserve evaluations have been prepared in accordance with NI 51-101. There are numerous uncertainties inherent in estimating quantities of reserves and cash flows to be derived therefrom, including many factors that are beyond the control of the Company. The reserves information set forth in this Annual Information Form represents estimates only. The reserves from the Company's properties have been independently evaluated by Sproule. These evaluations include a number of assumptions relating to factors such as future prices of oil and natural gas, initial production rates, production decline rates, ultimate recovery of reserves, timing and amount of capital expenditures, marketability of production, operating costs and royalties and other government levies that may be imposed over the producing life of the reserves. These assumptions were based on price forecasts in use at the date the relevant evaluations were prepared and many of these assumptions are subject to change and are beyond the control of the Company. Actual reserves, production and cash flows derived therefrom will vary from these evaluations, and such variations could be material. These evaluations are based, in part, on the assumed success of exploitation activities intended to be undertaken in future years. The reserves and estimated cash flows to be derived therefrom contained in such evaluations will be reduced to the extent that such exploitation activities do not achieve the level of success assumed in the evaluations.

Under IFRS, impairment testing is performed at the cash generating unit level ("**CGU**"), with asset carrying values being compared to the recoverable amount which is the higher of the value-in-use and fair value less costs to sell. Value in use is defined as the amount equal to the present value of future cash flows expected to be derived from the asset. When the asset carrying value (including goodwill) is less than the recoverable amount an impairment loss is recorded. A decline in the proved and probable reserve values of the oil and natural gas properties could result in the carrying value of the assets exceeding the recoverable amount, resulting in an impairment loss. Impairment losses that were previously recognized may be reversed where circumstances change such that the impairment is reduced, provided however any impairment losses associated with goodwill are permanent and not reversible. The Company did record a $700 million impairment expense in 2014, primarily as a result of reduced commodity price forecasts.

Operating Costs and Production Levels

An increase in operating costs or a decline in our production level could have a material adverse effect on our results of operations and financial condition and, therefore, could impact future dividends to shareholders as well as affect the market price of the Common Shares. Electricity, trucking, chemicals, supplies, reclamation and abandonment and labour costs are a few of the operating costs that are susceptible to material fluctuation. The level of production from our existing properties may decline at rates greater than anticipated due to unforeseen circumstances, many of which are beyond our control. A significant decline in our production could result in materially lower revenues and cash flow and, therefore, could adversely affect the trading price of the Common Shares.

Marketing of Oil and Natural Gas Production

Our business depends in part upon the availability, proximity and capacity of oil and gas gathering systems, pipelines and processing facilities to our assets. Canadian federal and provincial, as well as United States federal and state, regulation of oil and gas production, processing and transportation, tax and energy policies, general economic conditions, weather, pipeline disruptions, refinery capacity and changes in supply and demand could adversely affect our ability to produce and market oil and natural gas. If market factors change and inhibit the marketing of our production, overall production or realized prices may decline, which could result in materially lower revenues and cash flow and may adversely affect the market price of the Common Shares.

New resource plays generally experience a sharp increase in the amount of production being produced in the area which could exceed the existing capacity of the various gathering, processing and pipeline infrastructure. For example, pipeline and facility constraints experienced by oil producers in the Cardium area of Alberta have become more pronounced as a result of increased drilling and development activities in these regions. If these constraints remain unresolved, the Company's ability to produce and transport our production in these regions may be impaired and could adversely impact the Company's production volumes or realized prices from these areas.

Oil and natural gas producers in North America, and particularly Canada, currently receive discounted prices for their production due to constraints on the ability to transport and sell such production to international markets. Also, limited natural gas processing and fractionation capacity may result in producers not realizing the full price for liquids associated with their natural gas production. A failure to resolve such constraints may result in shut-in production or continued reduced commodity prices received by oil and natural gas producers.

While the third party pipelines generally expand capacity to meet market needs, there can be differences in timing between the growth of production and the growth of pipeline capacity, and unfavourable economic conditions or financing terms may defer or prevent the completion of certain pipeline projects or gathering systems that are planned for such areas. There are also occasional operational reasons, including as a result of maintenance activities, for curtailed transportation capacity. Accordingly, there can be periods where transportation capacity is insufficient to accommodate all of the production from a given region, causing added expense and/or volume curtailments for all shippers. In such event, the Company may have to defer development of or shut in our wells awaiting a pipeline connection or capacity and/or sell our production at lower prices than it would otherwise realize or than the Company currently projects, which would adversely affect the Company's results of and cash flow from operations.

Fluctuations in Foreign Currency Exchange Rates

Fluctuations in foreign currency exchange rates could adversely affect our business, and could affect the market price of the Common Shares, Senior Notes and payments of future dividends to shareholders. The price that we receive for a majority of our oil and natural gas is based on United States dollar denominated benchmarks, and, therefore, the price that we receive in Canadian dollars is affected by the exchange rate between the two currencies. A material increase in the value of the Canadian dollar relative to the United States dollar may negatively impact net production revenue by decreasing the Canadian dollars received for a given United States dollar price, negatively impacting future dividends and the future value of the Company's reserves as determined by independent evaluators. In addition, a significant portion of the Company's long term debt is denominated in US dollars and, while providing a hedge against the revenue stream, the fluctuation in the exchange rate may impact the amount of Canadian dollars required to settle these obligations. We could be subject to unfavourable price changes to the extent that we have engaged, or in the future engage, in risk management activities related to foreign exchange rates, through entry into forward foreign exchange contracts or otherwise.

Reliance on Third Party Operators

The continuing production from a property, and to some extent the marketing of that production, is dependent upon the ability of the operators of the Company's properties. In 2014, approximately 6% of the Corporation's production was from properties operated by third parties. This results in significant reliance on third party operators in both the operation and development of such properties and control over capital expenditures relating thereto. The timing and amount of capital required to be spent by the Company may differ from the Company's expectations and planning, and may impact the ability and/or cost of the Company to finance such expenditures, as well as adversely affect other parts of the Company's business and operations. To the extent a third party operator fails to perform these duties properly, faces capital or liquidity constraints or becomes insolvent, the Company's results of operations will be negatively impacted.

Key Personnel

The Company's success depends, to a significant extent, upon management and key employees. The loss of key employees could have a negative effect on our business, financial condition, results of operations and prospects. The Company faces significant competition for skilled personnel. There is no assurance that the Company will successfully attract and retain personnel required to successfully execute our business strategy.

Availability of Drilling Equipment and Access

Oil and natural gas exploration and development activities are dependent on the availability of drilling and related equipment (typically procured from third parties) in the particular areas where such activities are conducted. Demand for such limited equipment or access restrictions may affect the availability of such equipment and may delay exploration and development activities.

Operating Hazards

Oil and natural gas exploration, development and production operations are subject to all the risks and hazards typically associated with such operations, including hazards such as fire, explosion, blowouts, and oil spills, each of which could result in substantial damage to oil and natural gas wells, production facilities, other property and the environment or in personal injury. In accordance with industry practice, the Company is not fully insured against all of these risks, nor are all such risks insurable. Although Lightstream maintains liability insurance in an amount that it considers adequate and consistent with industry practice, the nature of these risks is such that liabilities could exceed policy limits, in which event Lightstream could incur significant costs that could have a materially adverse effect upon our financial condition. Oil and natural gas production operations are also subject to all the risks typically associated with such operations, including premature decline of reservoirs and the invasion of water into producing formations.

Abandonment and Reclamation Costs

Lightstream will be responsible for compliance with terms and conditions of environmental and regulatory approvals and all laws and regulations regarding abandonment and reclamation in respect of our properties, which abandonment and reclamation costs may be substantial. A breach of such legislation or regulations may result in the imposition of fines and penalties, including an order for cessation of operations at the site until satisfactory remedies are made.

Global Economic Conditions

Market events and conditions, including disruptions in the international credit markets and other financial systems and the deterioration of global economic conditions, may cause significant volatility to commodity prices. These conditions can cause a loss of confidence in the broader Canadian, U.S. and global credit and financial markets and result in the collapse of, and government intervention in, major banks, financial institutions and insurers and creating a climate of greater volatility, less liquidity, widening of credit spreads, a lack of price transparency, increased credit losses and tighter credit conditions. Notwithstanding various actions by governments, concerns about the general condition of the capital markets, financial instruments, banks, investment banks, insurers and other financial institutions caused the broader credit markets to further deteriorate and stock markets to decline substantially. In addition to impacting commodity prices, such economic conditions may adversely impact our ability to access equity and debt capital.

Environmental Regulation

All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of federal, provincial and local laws and regulations. Environmental legislation provides for, among other things, restrictions and prohibitions on spills, releases or emissions of various substances produced in association with oil and natural gas operations. The legislation also requires that wells and facility sites be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. Compliance with such legislation can require significant expenditures and a breach of applicable environmental legislation may result in the imposition of fines and penalties, some of which may be material.

Environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liability and potentially increased capital expenditures and operating costs. The discharge of oil, natural gas or other pollutants into the air, soil or water may give rise to liabilities to governments and third parties and may require the Company to incur costs to remedy such discharge. In certain areas where the Company operates, spills, releases and other environmental and safety issues can also occur as a result of sabotage and damage to the pipelines. Depending on the cause and severity of an environmental incident, the Company's reputation may also be adversely affected, which could limit our ability to obtain permits and implement our future plans. Although we believe that the Company is in material compliance with current applicable environmental regulations, no assurance can be given that environmental laws will not result in a curtailment of production or a material increase in the costs of production, development or exploration activities or otherwise have a material adverse effect on our business, financial condition, results of operations and prospects. Additionally, although the Company currently is not a party to any material environmental litigation, there can be no assurance that the Company will not become subject to such legal proceedings in the future, which may have a material adverse effect on our business, financial condition, results of operations and prospects.

Climate Change

Our exploration and production facilities and other operations and activities emit GHGs and require us to comply with GHG emissions legislation at the provincial and federal levels. Climate change policy is evolving at regional, national and international levels, and political and economic events may significantly affect the scope and timing of climate change measures that are ultimately put in place. As a signatory to the United Nations Framework Convention on Climate Change (the "**UNFCCC**") and as a participant to the Copenhagen Agreement (a non-binding agreement created by the UNFCCC), the Government of Canada announced on January 29, 2010 that it will seek a 17% reduction in GHG emissions from 2005 levels by 2020. These GHG emission reduction targets are not binding. However, although it is not the case today, some of our significant facilities may ultimately be subject to future regional, provincial and/or federal climate change regulations to manage GHG emissions. The direct or indirect costs of compliance with these regulations may have a material adverse effect on our business, financial condition, results of operations and prospects. Given the evolving nature of the debate related to climate change and the control of GHGs and resulting requirements, it is not possible to predict the impact on us and our operations and financial condition. See "Industry Conditions – Greenhouse Gases and Industrial Air Pollutants".

Potential Risks Associated with Hydraulic Fracturing

Lightstream utilizes horizontal drilling, multi-stage hydraulic fracturing, specially formulated drilling fluids and other technologies in connection with our drilling and completion activities. There has been public concern over the hydraulic fracturing process. Most of these concerns have raised questions regarding the completion fluids used in the fracturing process, their effect on fresh water aquifers, the use of water in connection with completion operations and the ability of such water to be recycled and the potential for induced seismicity associated with fracturing. Certain government and regulatory agencies in Canada and the United States have begun investigating the potential risks associated with the hydraulic fracturing process. The U.S. and Canadian federal governments and certain U.S. state and Canadian provincial governments are currently reviewing certain aspects of the scientific, regulatory and policy framework under which hydraulic fracturing operations are conducted. At present, most of these governments are primarily engaged in the collection, review and assessment of technical information regarding the hydraulic fracturing process and, with the exception of increased chemical disclosure requirements in certain of the jurisdictions in which the Corporation operates, have not provided specific details with respect to any significant actual, proposed or contemplated changes to the hydraulic fracturing regulatory construct. However, certain environmental and other groups have suggested that additional federal, provincial, territorial, state and municipal laws and regulations may be needed to more closely regulate the hydraulic fracturing process, and have made claims that hydraulic fracturing techniques are harmful to surface water and drinking water sources and may contribute to earthquake activity particularly where in proximity to pre-existing faults. Further, certain governments in jurisdictions where the Corporation does not currently operate have considered a temporary moratorium on hydraulic fracturing until further studies can be completed and some governments have adopted, and others have considered adopting, regulations that could impose more stringent permitting, disclosure and well construction requirements on hydraulic fracturing operations.

It is anticipated that federal, provincial and state regulatory frameworks to address concerns related to hydraulic fracturing will continue to emerge. While we are unable to predict the impact of any potential regulations upon our business, the implementation of new regulations with respect to water usage or hydraulic fracturing generally could increase the Company's costs of compliance, operating costs, the risk of litigation and environmental liability, or negatively impact the Company's prospects, any of which may have a material adverse effect on our business, financial condition and results of operations.

Changes in Laws, Regulations or Government Policy

The oil and gas industry in general is subject to extensive government policies and regulations, which result in additional cost and risk for industry participants. Changes in tax and other laws may adversely affect the value of our Common Shares. Income tax laws, royalty rates, other laws or government incentive programs relating to the oil and gas industry may in the future be changed or interpreted in a manner that adversely affects the Company and our shareholders. Tax authorities having jurisdiction over the Company or the shareholders may disagree with the manner in which we calculate our income for tax purposes or could change their administrative practices to our detriment or the detriment of our shareholders.

Changes to Accounting Policies

IFRS requires that management apply certain accounting policies and make certain estimates and assumptions, which affect reported amounts in the consolidated financial statements of the Company. Accounting policies are continuously updated by the International Accounting Standards Board ("**IASB**") with the Company being required to adopt these revisions. Adoption of new accounting policies could have a negative impact on the Company's earnings.

Permits, Licenses and Leases

Significant parts of the Company's operations require permits, licenses and leases from various governmental authorities and landowners. There can be no assurance that the Company will be able to obtain all necessary permits, licenses and leases that may be required to carry out exploration and development at our projects. If the present permits, licenses and leases are terminated or withdrawn, such event could have an adversely negative effect of the Company's operations.

Title to Properties

Although title reviews are done according to industry standards prior to the purchase of most oil and natural gas producing properties or the commencement of drilling wells, such reviews do not guarantee or certify that an unforeseen defect in the chain of title will not arise to defeat the claim of Lightstream which could result in a reduction of the revenue received by Lightstream.

Potential Liability Regarding Tax Reassessments

Predecessor companies of Lightstream have filed tax returns and issued "flow-through shares" whereby certain tax benefits generated from their capital expenditure programs have been renounced to investors. Should these tax returns or renouncements of capital expenditures be audited there exists a risk that the Company could become liable for incremental income taxes and penalties and could be required to indemnify investors as a result of any reduction in benefits received.

Lightstream may be subject to tax reassessments in the future as a result of audits conducted by the Canada Revenue Agency. While the Company believes there would be no material impact from any potential reassessment, if such a reassessment were to be successful it could result in cash taxes, interest and penalties to be paid as well as reduction in tax pools available to the Company to reduce future income taxes and such amounts could be material.

Conflicts of Interest

Certain of the officers and directors of the Company may have associations with other oil and gas companies or with other industry participants with whom the Company conducts business and situations may arise where the directors and officers will be in direct competition with the Company. Conflicts, if any, will be subject to the procedures and remedies under the ABCA.

Please also see the information under the heading *"Risks and Uncertainties"* in the Company's MD&A for the year ended December 31, 2014. The Company's MD&A was filed on SEDAR March 13, 2015 under our profile at www.sedar.com.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

Except as disclosed herein, no director, executive officer, or person or company that is the direct or beneficial owner of, or who exercises control or direction over, more than 10 percent of the common shares and no associate or affiliate of any of the foregoing has, or has had, any material interest in any transaction prior to the date hereof or any proposed transaction that has materially affected or will materially affect the Company.

LEGAL PROCEEDINGS

There are no legal proceedings involving claims for damages in an amount exceeding 10% of Lightstream's current assets to which Lightstream is or was a party or in respect of which any of our properties are or were subject during the year ended December 31, 2014, nor are there any such proceedings known to Lightstream to be contemplated.

MATERIAL CONTRACTS

Lightstream has US$800 million in principal amount of Senior Notes outstanding. The Senior Notes were issued pursuant to the Note Indenture. The Note Indenture remains in effect and is a material contract to Lightstream. See *"Capital Structure – Senior Notes"* for further information.

The Shareholder Rights Plan may be considered a material contract to Lightstream. See *"Capital Structure – Shareholder Rights Plan"* for further information.

TRANSFER AGENT AND REGISTRAR

The Company's transfer agent and registrar for the Common Shares is Computershare, located at 600, 530 – 8th Avenue SW, Calgary, Alberta T2P 3S8.

INTERESTS OF EXPERTS

Deloitte LLP, Chartered Accountants, are the Company's auditors and as such have prepared an opinion with respect to the Company's consolidated financial statements as at and for the fiscal year ended December 31, 2014. Deloitte LLP is independent within the meaning of the Rules of Professional Conduct as outlined by the Institute of Chartered Accountants of Alberta.

Information relating to reserves in this Annual Information Form was calculated by Sproule as Lightstream's independent qualified reserves evaluator. The principals of Sproule, individually or as a group, neither own nor expect to receive any of Lightstream's securities, directly or indirectly.

ADDITIONAL INFORMATION

Additional information relating to the Company may be found on SEDAR at www.sedar.com.

Additional information, including information as to directors' and officers' remuneration and indebtedness, principal holders of the Company's securities, options to purchase securities and interests of insiders in material transactions, will be available in the Management Proxy Circular of the Company provided for the annual meeting of the shareholders of the Company to be held on May 14, 2015, to be made available at www.sedar.com or at www.lightstreamresources.com. Additional financial information is also provided in the Company's consolidated financial statements and Management's Discussion and Analysis for the year ended December 31, 2014 which are available at www.sedar.com or at www.lightstreamresources.com.

APPENDIX A

FORM 51-101F3
REPORT OF MANAGEMENT AND DIRECTORS ON OIL AND GAS DISCLOSURE

Management of Lightstream Resources Ltd. (the "**Company**") is responsible for the preparation and disclosure of information with respect to the Company's oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data.

Independent qualified reserves evaluators have evaluated the Company's reserves data. The report of the independent qualified reserves evaluators will be filed with securities regulatory authorities concurrently with this report.

The Reserves Committee of the Board of Directors of the Company has:

(a) reviewed the Company's procedures for providing information to the independent qualified reserves evaluators;
(b) met with the independent qualified reserves evaluators to determine whether any restrictions affected the ability of the independent qualified reserves evaluators to report without reservation; and
(c) reviewed the reserves data with management and the independent qualified reserves evaluators.

The Reserves Committee of the Board of Directors has reviewed the Company's procedures for assembling and reporting other information associated with oil and gas activities and has reviewed that information with management. The Board of Directors has, on the recommendation of the Reserves Committee, approved:

(a) the content and filing with securities regulatory authorities of Form 51-101F1 containing reserves data and other oil and gas information;
(b) the filing of Form 51-101F2 which is the report of the independent qualified reserves evaluators on the reserves data, and
(c) the content and filing of this report.

Because the reserves data are based on judgments regarding future events, actual results will vary and the variations may be material.

(signed) ***"John D. Wright"***
John D. Wright
President, Chief Executive Officer and Member of the Reserves Committee

(signed) ***"Peter D. Scott"***
Peter D. Scott
Senior Vice President and Chief Financial Officer

(signed) ***"Dan Themig"***
Dan Themig
Director and Member of the Reserves Committee

(signed) **"W. Brett Wilson"**
W. Brett Wilson
Director and Member of the Reserves Committee

Dated: March 31, 2015

APPENDIX B

FORM 51-101F2
REPORT ON RESERVES DATA BY
INDEPENDENT QUALIFIED RESERVES EVALUATOR OR AUDITOR

To the Board of Directors of Lightstream Resources Ltd. (the "**Company**"):

1. We have evaluated the Company's reserves data as at December 31, 2014. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2014, estimated using forecast prices and costs.

2. The reserves data are the responsibility of the Company's management. Our responsibility is to express an opinion on the reserves data based on our evaluation.

3. We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook as amended from time to time (the "**COGE Handbook**") maintained by the Society of Petroleum Evaluation Engineers (Calgary Chapter).

4. Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the reserves data are free of material misstatement. An evaluation also includes assessing whether the reserves data are in accordance with principles and definitions presented in the COGE Handbook.

5. The following table shows the net present value of future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated for the year ended December 31, 2014, and identifies the respective portions thereof that we have audited, evaluated and reviewed and reported on to the Company's management and Board of Directors:

Independent Qualified Reserves Evaluator	Description and Preparation Date of Evaluation Report	Location of Reserves (Country)	Net Present Value of Future Net Revenue Before Income Taxes (10% Discount Rate)			
			Audited (M$)	Evaluated (M$)	Reviewed (M$)	Total (M$)
Sproule	Evaluation of the P&NG Reserves of Lightstream Resources Ltd., As of December 31, 2014, prepared September 2013 to February 2015	Canada				
Total			Nil	**3,150,412**	Nil	**3,150,412**

6. In our opinion, the reserves data respectively evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook, consistently applied. We express no opinion on the reserves data that we reviewed but did not audit or evaluate.

7. We have no responsibility to update our report referred to in paragraph 4 for events and circumstances occurring after the effective date of our report.

8. Because the reserves data are based on judgements regarding future events, actual results will vary and the variations may be material.

Executed as to our report referred to above:

Sproule Associates Limited
Calgary, Alberta, Canada
February 25, 2015

(signed) "*Paul B. Jung*"
Paul B. Jung, P.Eng.
Supervisor, Engineering and Partner

(signed) "*Richard A. Brekke*"
Richard A. Brekke, P.Eng.,
Manager, Engineering and Partner

(signed) "*Geoff W. Beatson*"
Geoff W. Beatson, P.Eng.
Manager, Engineering and Partner

(signed) "*Rod Fradette*"
Rod Fradette, P.Eng.
Senior Petroleum Engineering and Partner

(signed) "*Richard A. Brekke*"
Richard A. Brekke, P.Eng., signed on behalf of
Vincent Hui, P.Eng.
Petroleum Engineer and Partner

(signed) "*Stephanie D. Brunt*"
Stephanie D. Brunt, P.Eng
Petroleum Engineer and Associate

(signed) "*Alec Kovaltchouk*"
Alec Kovaltchouk, P.Geol.
Manager, Geoscience and Partner

(signed) "*Nora T. Stewart*"
Nora T. Stewart, P.Eng
Senior Vice-President, Canada and Partner

APPENDIX C

FORM 52-110F1
AUDIT COMMITTEE INFORMATION REQUIRED IN AN AIF

1. **The Audit Committee's Charter**

See Appendix "D" attached to this Annual Information Form for the text of Lightstream's Audit Committee charter.

2. **Composition of the Audit Committee**

Ian S. Brown – independent and financially literate.

Kenneth R. McKinnon – independent and financially literate.

Martin Hislop – independent and financially literate.

3. **Relevant Education and Experience**

Ian S. Brown: Mr. Brown has been a member of the Institute of Chartered Accountants since 1983. Mr. Brown was a Senior Managing Director at Raymond James Ltd. (formerly Goepel McDermid Inc.) from 1995 until December 2005, and was Executive Vice President at the Alberta Stock Exchange from 1986 to 1995. Mr. Brown is also Director of Bonavista Energy Trust and Cathedral Energy Services Ltd. Mr. Brown obtained his Bachelor of Arts from McMaster University in 1979 and his Bachelor of Commerce (Accounting) from the University of Windsor in 1980. Mr. Brown is a Chartered Accountant with over 25 years' experience in the financial markets. He has gained significant experience and expertise in analyzing financial statements and he has an understanding of internal controls and procedures for financial reporting. He has gained an understanding of Audit Committee functions through his Board and committee experience with other public corporations.

Kenneth R. McKinnon: Mr. McKinnon obtained his Bachelor of Commerce from the University of Calgary (Accounting) in 1980 and obtained his Bachelor of Laws from Queens University in 1983. Mr. McKinnon was the Vice President, Finance and Chief Financial Officer of Petrobank Energy and Resources Ltd. from November 1997 to March 2000 and has been a member of the Audit Committee on several other public companies. Over time he has gained experience in analyzing financial statements and he has an understanding of internal controls and procedures for financial reporting and has experience supervising persons engaged in the preparation, analysis and evaluation of financial statements. In 2006, he earned the ICD.D designation of the Institute of Corporate Directors, as a certified corporate director.

Martin Hislop: Mr. Hislop is a retired businessman with more than 40 years' experience in all aspects of financing and managing private and public oil and gas companies, partnerships and trusts. Mr. Hislop is also a director of Toscana Energy Income Corporation. Mr. Hislop is a Chartered Accountant and former Chief Executive Officer of APF Energy Trust. Prior to founding the predecessor of APF Energy Trust in September 1994, Mr. Hislop was the President and CEO of Lakewood Energy Inc., a TSX-listed oil and gas company which was created as a result of the combination of 10 limited partnerships.

4. **Reliance on Certain Exemptions**

N/A

5. **Reliance on the Exemption in Subsection 3.3(2) or Section 3.6**

N/A

6. **Reliance on Section 3.8**

N/A

7. **Audit Committee Oversight**

N/A

8. **Pre-Approval Policies and Procedures**

The Audit Committee requires the Company to obtain Audit Committee approval for any non-audit services exceeding immaterial amounts.

9. **External Auditor Service Fees (By Category)**

Year Ended	Audit Fees	Audit Related Fees[(1)]	Tax Fees[(2)]	All Other Fees[(3)]
2013	$250,000	$57,000	$152,000	$5,000
2014	$250,000	$57,000	$20,560	$5,000

Notes:

1. Audit related fees relate to quarterly reviews, the issuance of securities for Lightstream, and IFRS related procedures.
2. Tax fees relate to US tax compliance, assistance with respect to tax audits, and general tax advisory services.
3. Other fees relate to services provided in connection with the issuance of the Senior Notes.

APPENDIX D

AUDIT COMMITTEE OF THE BOARD OF DIRECTORS
MANDATE AND TERMS OF REFERENCE

I. PURPOSE

The primary function of the Audit Committee is to assist the Board of Directors (the "**Board of Directors**" or "**Board**") of Lightstream Resources Ltd. ("**Lightstream**" or the "**Corporation**") in fulfilling its responsibilities by reviewing: the financial reports and other financial information provided by Lightstream to any regulatory body or the public; the Corporation's systems of internal controls regarding preparation of those financial statements and related disclosures that management and the Board have established; and the Corporation's auditing, accounting and financial reporting processes generally. Consistent with this function, the Audit Committee should encourage continuous improvement of, and should foster adherence to, the Corporation's policies, procedures and practices at all levels. The Audit Committee's primary objectives are:

A. To assist directors in meeting their responsibilities in respect of the preparation and disclosure of the financial statements of the Corporation and related matters;

B. To provide for open communication between directors and external auditors;

C. To enhance the external auditor's independence;

D. To increase the credibility and objectivity of financial reports; and

E. To strengthen the role of the outside directors by facilitating in depth discussions between directors on the Audit Committee, management and external auditors.

II. COMPOSITION

1. The Audit Committee shall be comprised of three or more directors as determined by the Board of Directors, none of whom are members of management of Lightstream and all of whom are "unrelated directors" (as such term is used in the Report of the Toronto Stock Exchange on Corporate Governance in Canada) and "independent" (as such term is used in Multilateral Instrument 52-110 — Audit Committees ("**MI 52-110**") unless the Board shall have determined that the exemption contained in Section 3.6 of MI 52 110 is available and has determined to rely thereon.

2. All of the members of the Audit Committee shall be "financially literate" (as defined in MI 52-110) unless the Board shall determine that an exemption under MI 52-110 from such requirement in respect of any particular member is available and has determined to rely thereon in accordance with the provisions of MI 52-110.

3. The members of the Audit Committee shall be elected by the Board of Directors at the annual organizational meeting of the Board of Directors and remain as members of the Audit Committee until their successors shall be duly elected and qualified.

4. Unless a Chair is elected by the full Board of Directors, the members of the Audit Committee may designate a Chair by majority vote of the full Audit Committee membership.

III. MEETINGS

1. The Audit Committee shall meet at least four times annually, or more frequently as circumstances dictate. As part of its mandate to foster open communication, the Audit Committee should meet at least annually with management and the external auditors in separate executive sessions to discuss any matters that the Audit

Committee or each of these groups believe should be discussed privately. The Audit Committee or at least its Chair should meet with the external auditors and management quarterly to review the Corporation's financials consistent with Section IV.2 below. The Chief Financial Officer may, at the discretion of the Audit Committee, be present at meetings of the Audit Committee and may be excused from all or part of any such meetings by the Chairman.

2. Minutes of all meetings of the Audit Committee shall be taken and the Audit Committee shall report the results of its meetings and reviews undertaken and any associated recommendations to the Board of Directors.

3. A quorum for meetings of the Audit Committee shall be a majority of its members, and the rules for calling, holding, conducting and adjourning meetings of the Audit Committee shall be the same as those governing the Board.

IV. RESPONSIBILITIES AND DUTIES

To fulfill its responsibilities and duties, the Audit Committee shall:

Documents/Reports Review

1. Review and update this Charter, as conditions dictate.

2. Review the financial statements, prospectuses, MD&A, annual information forms and all public disclosure containing audited or unaudited financial information (including, without limitation, annual and interim press releases and any other press releases disclosing earnings or financial results) before release and prior to Board approval where required.

3. Review the reports to management prepared by the external auditors and management's responses.

4. Review of significant auditor findings during the year, including the status of previous audit recommendations.

5. Be satisfied with and periodically assess the adequacy of procedures for the review of corporate disclosure that is derived or extracted from the financial statements.

6. It is the responsibility of the Audit Committee to review, on behalf of the Board, the Corporation's internal control systems in order satisfy the Audit Committee that the internal control systems are sufficient to reasonably ensure that:

    (a) controllable, material business risks are identified, monitored and mitigated where it is determined cost effective to do so;

    (b) internal controls over financial reporting are sufficient to meet the requirements under Multilateral Instrument 52-109 of the Canadian Securities Administrators,

    (c) legal, ethical and regulatory requirements are complied with; and

    (d) major issues as to the adequacy of the Corporation's internal controls and any special audit stops adopted in light of material control deficiencies are reviewed with the Audit Committee by the Chief Financial Officer of the Corporation.

External Auditors

7. Be directly responsible for overseeing the work of the external auditors, including the resolution of disagreements between management and the external auditors regarding financial reporting.

8. Recommend to the Board the external auditors to be nominated for appointment by the shareholders.

9. Recommend to the Board the terms of engagement of the external auditor, including their compensation and a confirmation that the external auditors shall report directly to the Audit Committee.

10. On an annual basis, review and discuss with the auditors all significant relationships the auditors have with the Corporation to determine the auditors' independence.

11. Review the performance of the external auditors and approve any proposed discharge of the external auditors when circumstances warrant.

12. When there is to be a change in auditors, review the issues related to the change and the information to be included in the required notice to securities regulators of such change.

13. Periodically consult with the external auditors, without the presence of management, about internal controls and the fullness and accuracy of the organization's financial statements.

14. Consider, in consultation with the external auditor, the audit scope and plan of the external auditor.

15. Pre-approve the completion of any non-audit services by the external auditors and determine which non-audit services the external auditor is prohibited from providing and the Audit Committee may delegate to one or more independent members of the Audit Committee the authority to pre approve non audit services, provided that such member(s) reports to the Audit Committee at the next scheduled meeting such pre-approval and the member(s) complies with such other procedures as may be established by the Audit Committee from time to time.

Financial Reporting Processes

16. In consultation with the external auditors and management, review the integrity of the organization's financial reporting processes, both internal and external.

17. Consider judgments concerning the appropriateness of the Corporation's accounting policies.

18. Consider and approve, if appropriate, major changes to the Corporation's auditing and accounting principles and practices as suggested by the external auditors or management.

19. Review risk management policies and procedures of the Corporation (i.e., hedging, litigation and insurance).

20. Establish a procedure for:

    (a) the receipt, retention and handling of complaints received by the Corporation regarding accounting, internal accounting controls or auditing matters; and

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

21. Approve management recommendations of appointment of individuals to senior financial reporting positions within the Corporation.

Process Improvement

22. Establish regular and separate systems of reporting to the Audit Committee by management and the external auditors regarding any significant judgments made in management's preparation of the financial statements and the view of each group as to appropriateness of such judgments.

23. Following completion of the annual audit, review separately with management and the external auditors any significant difficulties encountered during the course of the audit, including any restrictions on the scope of work or access to required information.

24. Review with external auditors their assessment of internal controls, their written reports containing recommendations for improvement, and management's response and follow-up to any identified weaknesses. The Committee shall also review annually with the external auditors their plan for their audit and, upon completion of the audit, their reports upon the financial statements.

Ethical and Legal Compliance

25. Ensure that management has the proper review system in place to ensure that the Corporation's financial statements, reports and other financial information disseminated to regulatory organizations and the public satisfy legal requirements.

26. On at least an annual basis, review with the Corporation's counsel and/or management, any legal matters, compliance with applicable laws and regulations, or inquiries received from regulators or government agencies that could have a significant impact on the organization's financial statements.

27. Conduct and authorize investigations into any matters within the Audit Committee's scope of responsibilities. The Audit Committee shall be empowered to retain, and to set and pay compensation for any independent counsel and other professionals to assist in the conduct of any investigation.

28. Perform any other activities consistent with this Charter, the Corporation's by-laws and governing law, as the Audit Committee or the Board of Directors deems necessary or appropriate.

EXHIBIT 3 DATE Oct 3|16

WITNESS P. D. Scott
HEATHER BOWIE
COURT REPORTER

LIGHTSTREAM RESOURCES

MANAGEMENT'S DISCUSSION AND ANALYSIS:

The following Management's Discussion and Analysis ("MD&A") is dated August 4, 2016 and should be read in conjunction with the unaudited condensed consolidated financial statements and accompanying notes of Lightstream Resources Ltd. ("Lightstream", "we" or "our" or the "Company") as at and for the three and six months ended June 30, 2016 and 2015, MD&A for the year ended December 31, 2015, and the audited consolidated financial statements for the years ended December 31, 2015 and 2014. All amounts are in Canadian dollars, unless otherwise stated and all tabular amounts are in thousands of Canadian dollars, except per share amounts or as otherwise noted. Natural gas volumes have been converted to barrels of oil equivalent ("boe"). Six thousand cubic feet ("Mcf") of natural gas is equal to one barrel of oil equivalent based on an energy equivalency conversion method primarily attributable at the burner tip and does not represent a value equivalency at the wellhead. Boes may be misleading, especially if used in isolation. This MD&A contains financial measures that have no standardized meaning under International Financial Reporting Standards ("IFRS") and forward-looking statements. As such, the MD&A should be read in conjunction with Lightstream's disclosure under the headings "Non-GAAP Measures" and "Forward-Looking Information" at the end of this MD&A.

RECAPITALIZATION PLAN

On July 28, 2016, the Company entered into a definitive arrangement agreement with a new wholly-owned subsidiary to effect a series of transactions which will result in the recapitalization (the "Recapitalization") of the Company's US$650 million 9.875% secured notes due June 15, 2019 (the "Secured Notes"), the Company's US$254 million 8.625% unsecured notes due February 1, 2020 (the "Unsecured Notes") and the Company's common shares (the "Common Shares"). The proposed Recapitalization is intended to be implemented by way of a corporate plan of arrangement under the Canada Business Corporations Act (the "CBCA Plan"). Under a support agreement entered into on July 12, 2016, holders of 91.5% of the Company's Secured Notes (the "Initial Consenting Noteholders") have agreed, subject to certain conditions, to vote their securities in favour of the CBCA Plan. In addition, in connection with the completion of the Recapitalization, we are working towards a replacement credit facility for the Company's existing revolving credit facility (the "Credit Facility"). The Recapitalization is expected to reduce the Company's overall debt by approximately US$904 million (Cdn$1.175 billion) in principal and reduce our cash interest payments by over US$83 million (Cdn$108 million) per year.

As a result of the Company's failure to make the June 15 semi-annual interest payment on our Secured Notes by July 15, 2016, the Company triggered defaults under the Credit Facility, the Secured Notes indenture and the Unsecured Notes indenture. In anticipation of this, and as part of the CBCA Plan, on July 13, 2016, the Company received a preliminary interim order from the Court of Queen's Bench of Alberta containing a stay prohibiting any person, including the holders of Secured Notes and holders of Unsecured Notes, other than the lenders under the Credit Facility, from terminating, making any demand, accelerating, amending or declaring in default or taking any enforcement steps under any contract or other agreement to which the Company is a party. On July 12, 2016, the Company also entered into a forbearance agreement with the lenders under the Credit Facility. Pursuant to the forbearance agreement, as amended, the lenders have agreed to forbear from exercising their enforcement rights and remedies arising on account of existing defaults under the Credit Facility until August 5, 2016, including in respect of the Company's hedging liabilities. The Company has requested and anticipates receiving an extension to the forbearance relief period to August 12, 2016, however there is no assurance the Company will obtain this extension.

Subject to obtaining the forbearance extension and satisfactory commitments to provide the new revolving credit facility, the Company anticipates entering into a second forbearance agreement with the lenders prior to August 12, 2016 to extend the forbearance through the anticipated completion of the CBCA Plan and implementation of a new revolving credit facility.

SUMMARY SECOND QUARTER HIGHLIGHTS:

- Average production for the second quarter of 2016 was 25,116 boepd (65% light oil and liquids weighted), a 5% decrease from first quarter 2016 production of 26,350 boepd, and a 21% decrease from second quarter 2015 production of 31,966 boepd. The decrease is primarily attributed to our reduction in development capital spending, resulting in natural declines exceeding new well production additions, and a continued third party pipeline outage in the Swan Hills area.
- Our second quarter operating netback was $19.10/boe, a 69% increase over first quarter 2016, due primarily to higher realized oil prices. Our netback decreased 35% from the second quarter of 2015, due primarily to lower realized commodity prices, partially offset by lower royalties and production expenses.
- Adjusted EBITDA for the quarter was $37.3 million compared to $94.7 million for the second quarter of 2015. The decrease of 61% is primarily a result of lower realized commodity prices and production volumes in the current quarter.
- Funds flow from operations for the quarter was $3.8 million ($0.02 per basic share) compared to a deficit of $10.6 million in the first quarter of 2016, primarily resulting from higher realized oil prices. Funds flow from operations decreased 94% from the second quarter of 2015, primarily due to lower operating netback, lower production volumes and a reduction in commodity derivative contracts in place.
- Capital expenditures for the quarter of $7.5 million (before asset acquisitions and dispositions) were in line with first quarter 2016 expenditures of $7.4 million, and were 63% lower than second quarter 2015 expenditures of $20.2 million. The decrease in capital spending compared to prior year is consistent with our first half 2016 capital plan of limiting discretionary development capital investment to preserve the long-term value of our assets through the current low commodity price environment.
- We recognized an asset impairment charge of $789.8 million ($576.6 million after-tax) based on the difference between the carrying value and the estimated recoverable amount at June 30, 2016, and an additional $15.1 million ($11.0 million after-tax) of impairment relating to the expiry of exploration and evaluation assets. The impairment charge has been recognized as a result of our proposed Recapitalization, which includes a potential credit bid process for the sale of the assets of the Company.

SELECTED QUARTERLY RESULTS

	Three months ended June 30, 2016	2015	% Change	Six Months Ended June 30, 2016	2015	% Change
Financial ($000s, except where noted)						
Oil and natural gas sales	76,716	136,265	(44)	139,891	257,396	(46)
Adjusted EBITDA[1]	37,262	94,747	(61)	60,146	174,202	(65)
Funds flow from operations [1]	3,787	66,966	(94)	(6,823)	118,894	—
Per share - basic ($)[1]	0.02	0.34	(94)	(0.03)	0.60	—
- diluted ($)[1] [2]	0.02	0.34	(94)	(0.03)	0.60	—
Adjusted Net Income (loss)[1]	110,502	(51,533)	—	137,578	(178,695)	—
Per share - basic ($)[1]	0.56	(0.26)	—	0.69	(0.90)	—
- diluted ($)[1] [2]	0.56	(0.26)	—	0.69	(0.90)	—
Capital expenditures [3]	7,504	20,175	(63)	14,857	80,429	(82)
Net capital expenditures[1]	6,216	18,324	(66)	13,287	67,255	(80)
Total debt[1] [4]				1,574,576	1,668,123	(6)
Basic common shares, end of period				198,645	197,565	1
Operations						
Operating netback [1] ($/boe except where noted) [5]						
Oil, NGL and natural gas revenue	33.56	46.84	(28)	29.87	42.37	(30)
Royalties	2.73	4.47	(39)	2.73	4.54	(40)
Production expenses	11.48	12.89	(11)	11.77	12.68	(7)
Transportation expenses	0.25	0.30	(17)	0.26	0.30	(13)
Operating netback	19.10	29.18	(35)	15.11	24.85	(39)
Average daily production (boe/d)						
Oil and NGL (bbl/d)	16,333	23,066	(29)	17,103	24,827	(31)
Natural gas (mcf/d)	52,697	53,399	(1)	51,779	52,419	(1)
Total (boe/d) [5]	25,116	31,966	(21)	25,733	33,563	(23)

(1) Non-GAAP measure. See "*Non-GAAP Measures*" section within this document.

(2) Consists of common shares, stock options, deferred common shares, incentive shares and convertible debentures (if applicable) as at the period end date.

(3) Prior to asset acquisitions and dispositions.

(4) Total debt includes secured termed credit facility outstanding plus accounts payable less accounts receivable, prepaid expenses and long-term investments plus the full value outstanding on the secured notes and unsecured notes converted to Canadian dollars using the period end exchange rate of 0.77 at June 30, 2016 (June 30, 2015 - 0.79).

(5) Six Mcf of natural gas is equivalent to one barrel of oil equivalent ("boe").

FIRST HALF 2016 GUIDANCE

($000s, except where noted and per share amounts)	First Half 2016 Revised Guidance (May 4, 2016)	First Half 2016 Actual
Production (Six month average)		
Total (boe/d)	25,500 - 26,000	25,733
Light-oil and liquids weighting	66%	66%
Adjusted EBITDA[1]	$56,000	$60,146
Funds Flow from Operations[1]	($10,000)	($6,823)
Funds Flow per share[1][2]	($0.05)	($0.03)
Capital Expenditures[3]	$15,500 - $16,500	$14,857
Pricing Assumptions:	Q2 2016	Q2 2016
Crude oil - WTI (US$/bbl)	45.00	45.59
Crude oil - WTI (Cdn$/bbl)	58.44	58.76
Corporate light-oil to WTI differential (US$/bbl)[4]	6.19	4.73
Natural gas - AECO (Cdn$/mcf)	1.37	1.40
Exchange rate (Cdn$/US$)	0.77	0.78

(1) Non-GAAP measure. See *"Non-GAAP Measures"* section within this document.

(2) Funds flow per share calculation based on 198 million weighted average basic shares outstanding.

(3) Projected capital expenditures exclude acquisitions and divestitures, which are evaluated separately.

(4) Differential includes approximately US$2.00/bbl cost for tariffs and quality adjustments charged from western Canadian benchmark prices to our realized wellhead prices.

First half 2016 average production of 25,733 boepd was at the mid-point of our first half 2016 revised guidance. While we have not released guidance for the second half of 2016 due to the pending Recapitalization plan, we anticipate development capital spending to be minimal and production levels to decline for the remainder of 2016. We expect to announce guidance once the Recapitalization plan has been implemented.

With improved operating performance and stronger oil prices, funds flow from operations was positive in the second quarter of 2016. As a result, our funds flow deficit for the first half of 2016 was lower than expected. Adjusted EBITDA exceeded first half 2016 revised guidance due to higher than forecast second quarter 2016 operating netback, primarily resulting from lower production costs.

First half 2016 capital expenditures of $14.9 million were slightly below our first half 2016 guidance range as second quarter 2016 spending was lower than expected and generally in line with first quarter 2016 spending.

FINANCIAL AND OPERATING REVIEW

(Comparisons presented in this MD&A are second quarter of 2016 compared to the second quarter of 2015 unless otherwise noted. All references to well counts are on a net basis unless otherwise noted.)

Average Daily Production

	Three months ended June 30,			Six months ended June 30,		
	2016	2015	Change	2016	2015	Change
Oil and NGL (bbls)	16,333	23,066	(29%)	17,103	24,827	(31%)
Natural gas (Mcf)	52,697	53,399	(1%)	51,779	52,419	(1%)
Total (boe)	25,116	31,966	(21%)	25,733	33,563	(23%)

Oil and NGL production for the three and six months ended June 30, 2016 decreased 29% and 31% respectively from 2015, due primarily to natural well declines exceeding new well production additions, given our reduced development capital program and a pipeline outage that continued to restrict production in our Alberta/BC business unit. Natural gas production was essentially unchanged from second quarter 2015, as favorable results from our Falher liquids-rich gas play in the Cardium business unit have offset natural declines. During the second quarter of 2016, no new wells were brought on production compared to six wells in the second quarter of 2015. For the first six months of 2016, we brought two wells on production compared to 26 wells during the same period a year ago. At June 30, 2016, there was one (0.3 net) Cardium well in inventory that is scheduled to come on production during the third quarter.

In southeast Saskatchewan, our Bakken business unit averaged 8,939 boepd of production during the second quarter of 2016, representing an 6% decrease from first quarter 2016 production of 9,530 boepd, and a 24% decrease from second quarter 2015 volumes of 11,720 boepd. The decrease is due to continued attenuation of investment in the Bakken given the challenging economic environment for drilling new wells. There were no Bakken wells brought on production in the second quarter of 2016 compared to one well on production in the second quarter of 2015.

In our Cardium business unit, second quarter 2016 production averaged 14,655 boepd, which was essentially unchanged from first quarter 2016 production of 14,676 boepd. Second quarter 2016 production decreased 16% from second quarter 2015 volumes of 17,455 boepd. The decrease is due primarily to natural declines and reduced new well spending. There were no Cardium wells brought on production in the second quarter of 2016 compared to five wells on production in the second quarter of 2015.

In our Alberta/BC business unit, second quarter 2016 production averaged 1,522 boepd, representing a 29% decrease from first quarter 2016 production of 2,144 boepd, and a 45% decrease from second quarter 2015 volumes of 2,791 boepd. The decrease is due to higher downtime from a third party pipeline outage on non-operated production and natural declines given the limited new well spending in the area. The pipeline outage was rectified early in the third quarter.

Average Benchmark and Realized Prices

	Three months ended June 30, 2016	2015	Change	Six months ended June 30, 2016	2015	Change
WTI (US$/bbl)	45.59	57.94	(21%)	39.52	53.29	(26%)
WTI ($/bbl)	58.76	71.05	(17%)	52.32	65.70	(20%)
Edmonton Par	54.78	67.55	(19%)	47.79	59.74	(20%)
Differential % of WTI	(7%)	(5%)	—	(9%)	(9%)	—
AECO natural gas ($/Mcf)	1.40	2.69	(48%)	1.62	2.74	(41%)
Cdn$ per US$1	0.78	0.82	(5%)	0.76	0.81	(6%)
Oil and NGL						
Realized price per bbl ($/bbl)	47.36	58.71	(19%)	40.17	51.50	(22%)
Differential % of Edm. Par	(14%)	(13%)	—	(16%)	(14%)	—
Differential % of WTI	(19%)	(17%)	—	(23%)	(22%)	—
Natural gas						
Realized price per Mcf ($/Mcf)	1.32	2.68	(51%)	1.58	2.74	(42%)

Realized oil and NGL prices decreased for the three and six month periods ended June 30, 2016, due to lower WTI oil prices as global oil supply continued to outpace demand. A weaker Canadian dollar relative to the U.S. dollar partially offset the impact of lower WTI oil prices. Corporate oil differentials narrowed in absolute terms from the prior year. Our second quarter 2016 realized oil differential to C$WTI was C$6.09 per bbl, or 10 percent, compared to C$6.81 per bbl, or 10 percent, in Q2 2015. Our realized oil differential to C$WTI for the first six months of 2016 was C$7.82 per bbl, or 18 percent, compared to C$9.53 per bbl, or 18 percent, for the same period in 2015. The decrease in realized natural gas prices from 2015 is due to lower AECO spot pricing as a result of higher natural gas supply and elevated storage levels.

Revenue

	Three months ended June 30, 2016	2015	Change	Six months ended June 30, 2016	2015	Change
Oil and natural gas sales	76,716	136,265	(44%)	139,891	257,396	(46%)
$ per boe	33.56	46.84	(28%)	29.87	42.37	(30%)

The decrease in oil and natural gas sales for the three and six months ended June 30, 2016 was due to lower realized commodity prices and the decrease in sales volumes. The table below summarizes these changes:

Reconciliation of Changes in Sales

Three months ended June 30, 2015	136,265
Sales volumes	(20,924)
Realized prices	(38,625)
Three months ended June 30, 2016	76,716
$ change in sales	(59,549)
% change in sales	(44%)

Reconciliation of Changes in Sales

Six months ended June 30, 2015	257,396
Sales volumes	(41,563)
Realized prices	(75,942)
Six months ended June 30, 2016	139,891
$ change in sales	(117,505)
% change in sales	(46%)

Royalties

	Three months ended June 30,			Six months ended June 30,		
	2016	2015	Change	2016	2015	Change
Royalties	6,233	13,002	(52%)	12,803	27,588	(54%)
$ per boe	2.73	4.47	(39%)	2.73	4.54	(40%)
Royalties % (1)	8%	10%	—	9%	11%	—

(1) Royalties % is shown as a % of realized price.

Royalties decreased for the three and six months ended June 30, 2016, on both a total and unit of production basis, commensurate with the decrease in revenues and a lower royalty rate. The decrease in royalty rate was primarily driven by lower benchmark pricing on crown royalty formulas, offset somewhat by the expiry of royalty incentives on existing Cardium wells. On Crown lands in Saskatchewan, the first 37,740 boe of production from horizontal wells receive a royalty incentive but incur the Saskatchewan Resource Surcharge which is determined as 1.7% of sales from our Saskatchewan lands. On Crown lands in Alberta, existing horizontal oil wells and new wells drilled in 2016 will be subject to a maximum 5% royalty rate for 12 to 48 months or 50,000 to 100,000 boe of production, whichever comes first, depending on well length.

Gain (Loss) on Risk Management Contracts

Lightstream typically enters into commodity price derivative contracts to limit exposure to declining commodity prices, thereby helping to protect project economics and providing increased stability of cash flows and capital expenditure programs. Commodity prices fluctuate for a number of reasons, including changes in economic conditions, political events, weather conditions and changes in supply or demand. The Company's risk management activities are conducted pursuant to the Company's risk management policies that have been approved by the Board of Directors. Given our current circumstances regarding our credit facility, we have suspended entering into new risk management contracts.

Lightstream typically enters into foreign exchange contracts to limit exposure to variability in exchange rates on U.S. dollar interest payments on the Secured Notes and Unsecured Notes, thereby providing increased stability of cash flows.

Our financial commodity derivative contracts that are option-based contracts have their fair value, at a particular point in time, impacted by underlying commodity prices, expected commodity price volatility and the duration of the contract. The fair value of our fixed price derivative contracts at a particular point in time is determined by the expected future settlements of the underlying commodity. The fair value of these contracts represents the estimated amount that would be received for settling Lightstream's outstanding contracts on June 30, 2016, and will be different than what will eventually be realized.

The gain or loss on risk management contracts is comprised of two components; the realized component reflects actual settlements that occurred during the period, and the unrealized component represents the change in the fair value of contracts during the period less realized contracts expiring during the period. The realized gain on risk management contracts for the three and six months ended June 30, 2016 was primarily driven by settlements on our WTI oil derivative contracts. The unrealized loss on risk management contracts for the three and six months ended June 30, 2016 resulted primarily from the reduction in total outstanding risk management contracts, partially offset by a decrease in expected future WTI price as compared to December 31, 2015.

	Three months ended June 30,			Six months ended June 30,		
	2016	2015	Change	2016	2015	Change
Realized gain (loss):						
Crude oil derivative contracts	1,421	19,457	(93%)	6,787	47,810	(86%)
Natural gas derivative contracts	625	12	5,108%	1,137	12	9,375%
Foreign exchange contracts	(752)	(2)	37,500%	(366)	1,487	—
	1,294	19,467	(93%)	7,558	49,309	(85%)
Unrealized gain (loss):						
Crude oil derivative contracts	(5,257)	(37,074)	(86%)	(9,045)	(45,576)	(80%)
Natural gas derivative contracts	(1,258)	62	—	(415)	62	—
Foreign exchange contracts	514	262	96%	(207)	295	—
	(6,001)	(36,750)	(84%)	(9,667)	(45,219)	(79%)
Gain on risk management contracts	(4,707)	(17,283)	(73%)	(2,109)	4,090	—

Commodity Contracts

At June 30, 2016, Lightstream recorded a $0.1 million asset (December 31, 2015 - $9.5 million asset) related to our commodity price risk management contracts. The following is a summary of crude oil derivative contracts in place as of the date of this MD&A:

Crude Oil Price Risk Management Contracts – WTI[1]

Remaining Term	Volume (bopd)	Average Price ($/bbl) [1]	Type
Jul. 2016 - Dec. 2016	1,250	US$49.40	Fixed Price Swap

(1) Prices are the volume weighted average prices for the period.

The following is a summary of crude oil differential derivative contracts in place as of the date of this MD&A:

Crude Oil Differential Derivative Contracts – Edmonton SW

Remaining Term	Volume (bopd)	Average Differential ($/bbl) [1]	Type
Jul. 2016 - Dec. 2016	3,000	US$3.78	Fixed Price Swap

The following is a summary of natural gas derivative contracts in place as of the date of this MD&A:

Remaining Term	Volume (GJ/d)	Average Price ($/GJ) [1]	Type
Jul. 2016 - Dec. 2016	5,000	$2.91	Fixed Price Swap

(1) Prices are the volume weighted average prices for the period.

Foreign Exchange Contracts

At June 30, 2016, Lightstream recorded $nil (December 31, 2015 - $0.2 million asset) related to foreign exchange risk management contracts. No foreign exchange contracts were entered into as of the date of this MD&A.

Production Expenses

	Three months ended June 30,			Six months ended June 30,		
	2016	2015	Change	2016	2015	Change
Production expenses	26,238	37,497	(30%)	55,132	77,020	(28%)
$ per boe	11.48	12.89	(11%)	11.77	12.68	(7%)

Production expenses decreased, on a total and per boe basis, for the three and six months ended June 30, 2016 due primarily to lower variable costs associated with decreased production levels and several cost reduction initiatives within our core operating areas. The most significant reductions in production expenses from the prior year related to repairs and maintenance, field personnel, electricity/power, chemicals, trucking, workovers, and treating & processing costs, which collectively made up 75% of the total decrease in costs from second quarter 2015, and 67% of the total decrease in costs compared to the first six months of 2015.

Transportation Expenses

	Three months ended June 30,			Six months ended June 30,		
	2016	2015	Change	2016	2015	Change
Transportation expenses	579	872	(34%)	1,229	1,806	(32%)
$ per boe	0.25	0.30	(17%)	0.26	0.30	(13%)

Transportation expense consists primarily of clean oil trucking costs which decreased for the three and six months ended June 30, 2016, on a total and per boe basis, due to lower oil production and reduced trucking rates.

Operating Netback ($/boe)

	Three months ended June 30,			Six months ended June 30,		
	2016	2015	Change	2016	2015	Change
Oil, NGL and natural gas sales	33.56	46.84	(28%)	29.87	42.37	(30%)
Royalties	2.73	4.47	(39%)	2.73	4.54	(40%)
Production expenses	11.48	12.89	(11%)	11.77	12.68	(7%)
Transportation expenses	0.25	0.30	(17%)	0.26	0.30	(13%)
Operating netback [1]	19.10	29.18	(35%)	15.11	24.85	(39%)

[1] Non-GAAP measure. See "Non-GAAP Measures" section within this document.

The decrease in operating netback for the three and six months ended June 30, 2016 was primarily due to lower realized oil prices, partially offset by lower royalties, production expenses and transportation expenses.

General and Administrative Expenses

	Three months ended June 30,			Six months ended June 30,		
	2016	2015	Change	2016	2015	Change
General and administrative expenses	7,630	9,491	(20%)	17,329	22,438	(23%)
$ per boe	3.34	3.26	2%	3.70	3.69	—

General and administrative ("G&A") expenses decreased, on a total basis, for the three and six months ended June 30, 2016, due to personnel reductions, lower consulting costs and reduced information systems costs, which collectively made up 95% of the total decrease in costs from second quarter 2015, and 92% of the total decrease in costs compared to the first six months of 2015. Severance costs included in G&A for the first six months of 2016 were approximately $1.7 million (2015 - $2.5 million). G&A expenses increased slightly on a per boe basis, as the impact of decreased G&A costs were partially offset by lower production levels.

Share-based Compensation

	Three months ended June 30,			Six months ended June 30,		
	2016	2015	Change	2016	2015	Change
Share-based compensation	1,386	2,083	(33%)	1,912	3,494	(45%)

Share-based compensation expense relates to stock options, deferred common shares and incentive shares granted. The calculation of this non-cash expense is based on the fair value of the share-based compensation issued, amortized over the vesting period of the option and incentive share or immediately upon grant of the deferred common share.

Share-based compensation decreased for the three and six months ended June 30, 2016 due to an increased number of fully vested share-based awards compared to prior year and reversal of previously recognized compensation expense upon cancellation of share-based awards resulting from staff reductions.

Loss on Onerous Contract

	Three months ended June 30,			Six months ended June 30,		
	2016	2015	Change	2016	2015	Change
Loss on onerous contract	15,122	—	100%	15,122	—	100%

The loss on onerous contracts for the three and six months ended June 30, 2016 consists of two separate provisions recognized to account for vacant property and a marketing pipeline commitment. An onerous contract provision of $9.8 million has been recognized to account for vacant property that the Company is leasing. The loss provision was calculated based on the present value of future net lease payments at a discount rate of 12% over the next six years. An onerous contract provision of $5.3 million has also been recognized to account for a marketing pipeline commitment that requires the Company to meet committed volumes under the agreement. The Company anticipates that it will not be able to meet or mitigate all the volume requirements under the agreement which ends in July 2019. The estimated cash payments were discounted at 12% per annum.

Gain (Loss) on Dispositions

	Three months ended June 30,			Six months ended June 30,		
	2016	2015	Change	2016	2015	Change
Gain (loss) on dispositions	(675)	556	—	(310)	(1,332)	(77%)

The loss on dispositions for the three months ended June 30, 2016 was attributed to a non-core asset disposition in our Cardium business unit for proceeds of $1.3 million. The loss on dispositions for the six months ended June 30, 2016 includes the $0.7 million loss on disposal of non-core assets in our Cardium business unit during Q2 2016, partially offset by a gain of $0.3 million from non-core asset dispositions in Q1 2016 and $0.1 million of net adjustments to non-core asset dispositions that occurred in 2015. The gain on dispositions for the three months ended June 30, 2015 includes $0.2 million from the disposal of non-core assets in our Alberta/BC business unit during Q2 2015 and $0.4 million of adjustments to other non-core asset dispositions occurring in Q1 2015. The loss on dispositions for the six months ended June 30, 2015 includes $0.7 million from the disposition of royalty and fee title assets in our Alberta/BC business unit in Q1 2015 for gross proceeds of $12.4 million and $0.6 million from adjustments to other non-core asset dispositions that occurred in 2014 and 2015.

Gain (Loss) on Long-term Investments

	Three months ended June 30, 2016	2015	Change	Six months ended June 30, 2016	2015	Change
Gain (loss) on long-term investments	53	(250)	—	94	(416)	—

Long-term investments are held at fair value based on the quoted market share price. The gain on long-term investments for the three and six months ended June 30, 2016 reflects a higher average market closing price of the investments at June 30, 2016 as compared to December 31, 2015.

Interest and Other Expense

	Three months ended June 30, 2016	2015	Change	Six months ended June 30, 2016	2015	Change
Interest on secured notes	20,677	—	100%	42,739	—	100%
Interest on unsecured termed debt [(1)]	7,055	21,309	(67%)	14,600	42,790	(66%)
Interest on secured termed credit facility and other	5,571	6,474	(14%)	9,235	11,979	(23%)
Cash Interest and other	33,303	27,783	20%	66,574	54,769	22%
Accretion on unsecured termed debt	287	850	(66%)	618	1,698	(64%)
Accretion of decommissioning liability	1,025	1,317	(22%)	2,240	2,465	(9%)
Amortization of deferred financing costs	585	459	27%	1,164	852	37%
Other	—	—	—	—	(421)	100%
Interest and other expense	35,200	30,409	16%	70,596	59,363	19%

(1) Unsecured termed debt consists of unsecured notes and convertible debentures (if applicable).

Interest and other expense increased for the three and six months ended June 30, 2016, despite lower overall debt outstanding during the period, due to a weaker Canadian dollar relative to the U.S. dollar in 2016 compared to the prior year and a higher interest rate on the secured notes compared to the unsecured termed debt.

Both the secured notes and unsecured termed debt are denominated in U.S. dollars. Interest and accretion are translated to Canadian dollars using the average foreign exchange rate for the period. The average Cdn$/US$ exchange rate for the three and six months ended June 30, 2016 was 0.78 and 0.76 respectively, compared to 0.82 and 0.81 in the prior year. Interest on the Secured Notes and Unsecured Notes has been accrued but the Company has elected not to pay the semi-annual interest payments on the Secured Notes and Unsecured Notes due in the third quarter of 2016. During the third quarter of 2015, US$450 million of Secured Notes, bearing interest at 9.875% per annum, were issued in exchange for US$546 million of outstanding Unsecured Notes bearing interest at 8.625% per annum. A further US$200 million of Secured Notes were issued for cash proceeds used to reduce the outstanding borrowing under our Credit Facility.

Credit Facility interest expense includes interest on debt, stand-by fees, and fees on letters of credit. Interest expense on the Credit Facility decreased for the three and six months ended June 30, 2016 as the Credit Facility was paid down during the third quarter of 2015 using proceeds from the issuance of US$200 million Secured Notes. The average Credit Facility balance outstanding for Q2 2016 was $359 million (Q2 2015 - $640 million) and the average balance outstanding for the first six months of 2016 was $355 million (2015 - $629 million).

Foreign Exchange Gain (Loss)

	Three months ended June 30, 2016	2015	Change	Six months ended June 30, 2016	2015	Change
Unrealized foreign exchange gain (loss)	(3,422)	16,474	—	74,795	(69,005)	—
Realized foreign exchange gain (loss)	(68)	(123)	(45%)	(810)	(3,651)	(78%)
Foreign exchange gain (loss)	(3,490)	16,351	—	73,985	(72,656)	—

The Company recognizes foreign exchange gains/losses primarily due to the appreciation/depreciation of the Canadian dollar relative to the U.S. dollar. Our Secured Notes, Unsecured Notes and convertible debentures (if applicable) are denominated in U.S. dollars and, as a result, the majority of unrealized foreign exchange gains or losses relate to the change in the foreign exchange rate compared to the rate at the end of the previous period. A weaker Canadian dollar at June 30, 2016 compared to March 31, 2016 resulted in an unrealized foreign exchange loss for the three months ended June 30, 2016. A stronger Canadian dollar at June 30, 2016 compared to December 31, 2015 resulted in an unrealized foreign exchange gain for the six months ended June 30, 2016. The realized foreign exchange loss in the first six months of 2016 resulted from settlement of the U.S. denominated interest obligations on the unsecured notes and convertible debentures during Q1 2016 and was mitigated by a $0.4 million realized gain on foreign exchange risk management contracts.

Depletion and Depreciation ("D&D")

	Three months ended June 30, 2016	2015	Change	Six months ended June 30, 2016	2015	Change
Depletion and depreciation	55,610	87,008	(36%)	112,349	180,334	(38%)
$ per boe	24.33	29.91	(19%)	23.99	29.69	(19%)

D&D expense decreased for the three and six months ended June 30, 2016, due to lower production volumes and a lower cost base from asset dispositions and impairments.

Impairment

	Three months ended June 30, 2016	2015	Change	Six months ended June 30, 2016	2015	Change
Impairment	804,849	—	100%	813,512	—	100%

Impairment is recognized when the carrying value of an asset or group of assets exceeds its estimated recoverable amount, defined as the higher of its value in use or fair value less cost to sell. On July 12, 2016, the Company entered into a restructuring support arrangement in respect of the Recapitalization. A potential outcome of this plan is the Company having to sell assets during a depressed commodity environment, which could reduce the recoverable amount of the Company's assets. In the event the Company does not proceed with the CBCA Plan, the Company has agreed to sell assets for a prescribed value as part of a credit bid process in the Recapitalization plan. Management has used this value to ascribe the estimated recoverable amounts under the fair value less costs to sell calculations. These amounts were aggregated for each CGU and compared to the total carrying value of PP&E and E&E associated with that CGU. If the combined carrying value of PP&E and E&E exceeded the recoverable amount, an impairment expense was recognized.

The impairment tests indicated that the carrying value of the Company's Bakken CGU, Cardium CGU, Other Alberta CGU, and corporate and other assets exceeded the estimated recoverable amounts. Consequently, for the three and six months ended June 30, 2016, the Company recorded impairment expense totaling $789.8 million ($576.6 million after-tax) based on the difference between the carrying value at June 30, 2016 and the estimated recoverable amount. Additional impairment charges of $15.1 million ($11.0 million after-tax) and $23.8 million ($17.3 million after-tax) were recorded for the three and six months ended June 30, 2016, relating to the expiry of exploration and evaluation assets located in our Bakken, Alberta/BC and Cardium CGU's.

Any asset impairment that is recorded is recoverable in the future to its original value, less any associated depletion or depreciation expense relating to the asset, should there be indicators that the recoverable amount of the asset has increased in value since the time of recording the initial impairment.

Income Tax Recovery (Expense)

	Three months ended June 30,			Six months ended June 30,		
	2016	2015	Change	2016	2015	Change
Income tax recovery (expense)	175,481	(6,810)	—	197,377	6,687	2,852%

The income tax recovery for the three and six months ended June 30, 2016 relates to the non-cash change in the Company's deferred tax liabilities, which are determined as the after-tax difference between the carrying value and tax basis of the Company's assets and liabilities. The income tax recovery for the six months ended June 30, 2016 differs from the amount that arises when multiplying the net loss before taxes by the Company's statutory tax rate of 27% primarily due to the impact of unrealized foreign exchange gains, which are not taxable, and impairment charges.

During the second quarter of 2016, the Company received notices of reassessment ("Reassessments") from the Canada Revenue Agency, which seek to disallow approximately $277 million of tax pools in 2010 or subsequent years. The Company has filed Notices of Objection in response to the Reassessments. No cash taxes arise as a a result of the Reassessments and no provision for the potential income tax liability was recorded at June 30, 2016.

Net Loss

As summarized in the table below, the increase in Q2 2016 net loss compared to Q2 2015 is primarily due to an impairment charge, lower realized prices, lower sales volumes, a foreign exchange loss compared to a gain previously, and a loss on onerous contracts, partially offset by an income tax recovery compared to a an income tax expense previously, lower depletion and depreciation, a smaller loss on risk management contracts and lower production expenses. The increase in net loss for the six months ended June 30, 2016 compared to the same period in 2015 is due to an impairment charge, lower realized prices, lower sales volumes, the recognition of onerous contracts, and higher interest expense, partially offset by a higher income tax recovery, foreign exchange gain compared to a loss previously, lower depletion and depreciation, lower production expenses and lower royalties.

Reconciliation of Changes in Net Loss

	Three months ended June 30,	Six months ended June 30,
Net loss: June 30, 2015	(51,533)	(178,274)
Increase (decrease) due to:		
Sales volumes	(20,924)	(41,563)
Realized prices	(38,625)	(75,942)
Royalties	6,769	14,785
Gain (loss) on risk management contracts	12,576	(6,199)
Production expenses	11,259	21,888
Interest and other	(4,791)	(11,233)
Foreign exchange gain (loss)	(19,841)	146,641
Depletion and depreciation	31,398	67,985
Impairment	(804,849)	(813,512)
Loss on onerous contract	(15,122)	(15,122)
Income taxes	182,291	190,690
Other [1]	1,923	8,800
Net loss: June 30, 2016	**(709,469)**	**(691,056)**

[1] Includes transportation expense, share-based compensation, general and administrative expense, and gain (loss) on long-term investments.

Funds Flow from Operations

The decrease in funds flow from operations for the three and six months ended June 30, 2016 compared to the same period in 2015 is due to lower realized prices, lower sales volumes and lower realized gain on risk management contracts primarily due to the expiry of existing contracts, partially offset by lower production expenses.

Reconciliation of Changes in Funds Flow From Operations

	Three months ended June 30,	Six months ended June 30,
Funds flow from operations: June 30, 2015	66,966	118,894
Increase (decrease) due to:		
Sales volumes	(20,924)	(41,563)
Realized prices	(38,625)	(75,942)
Royalties	6,769	14,785
Production expenses	11,259	21,888
Cash interest expense	(5,520)	(11,805)
Realized gain on risk management contracts	(18,173)	(41,751)
Other [1]	2,035	8,671
Funds flow from operations: June 30, 2016	**3,787**	**(6,823)**

[1] Includes transportation expenses, cash general and administrative expense, realized FX gain (loss), and decommissioning liabilities settled.

Capital Expenditures

	Three months ended June 30, 2016	Three months ended June 30, 2015	Change	Six months ended June 30, 2016	Six months ended June 30, 2015	Change
Drilling, completions, equipping and recompletions	4,135	8,237	(50%)	8,628	59,426	(85%)
Land	491	589	(17%)	848	1,111	(24%)
Facilities	699	8,176	(91%)	1,066	15,365	(93%)
Seismic	(14)	53	—	1	(991)	(100%)
Other	2,193	3,120	(30%)	4,314	5,518	(22%)
Capital expenditures before acquisitions[1]	7,504	20,175	(63%)	14,857	80,429	(82%)
Asset acquisitions	—	84	—	—	84	(100%)
Proceeds from dispositions	(1,288)	(1,935)	(33%)	(1,570)	(13,258)	(88%)
Net capital expenditures	6,216	18,324	(66%)	13,287	67,255	—

(1) Includes exploration and evaluation expenditures for the three and six months ended June 30, 2016 of $nil (2015 - $nil) and $nil (2015 - $0.1 million) respectively.

Drilling Activity (Net), for the three months ended June 30,

Business Unit	Net wells drilled 2016	Net wells drilled 2015	Net wells pending completion and/or tie-in 2016	Net wells pending completion and/or tie-in 2015	Dry and abandoned wells 2016	Dry and abandoned wells 2015	Success Rate 2016	Success Rate 2015
Bakken	—	1.4	—	2.4	—	—	—	100%
Cardium	0.3	—	0.3	0.5	—	—	100%	—
Alberta/BC	—	—	—	—	—	—	—	—
Total	0.3	1.4	0.3	2.9	—	—	100%	100%

Drilling Activity (Net), for the six months ended June 30,

Business Unit	Net wells drilled 2016	Net wells drilled 2015	Net wells pending completion and/or tie-in 2016	Net wells pending completion and/or tie-in 2015	Dry and abandoned wells 2016	Dry and abandoned wells 2015	Success Rate 2016	Success Rate 2015
Bakken	0.5	7.2	—	2.4	—	—	100%	100%
Cardium	0.3	8.1	0.3	0.5	—	—	100%	100%
Alberta/BC	—	—	—	—	—	—	—	—
Total	0.8	15.3	0.3	2.9	—	—	100%	100%

In order to preserve the long-term value of our assets through the current downturn in commodity prices, we significantly reduced the amount of development capital spending in the first half of 2016 as compared to the prior year. As a result, first half 2016 capital expenditures of $15 million, before asset acquisitions and dispositions, were 82% lower than first half 2015. Our limited capital program focused on capital maintenance projects, optimization and Enhanced Oil Recovery initiatives to moderate declines within our core areas.

We also participated in drilling one (0.3 net) Cardium oil well during the second quarter of 2016, which was in inventory at June 30, 2016 and went on production early in the third quarter. During the first six months of 2016, we drilled two (0.8 net) wells compared to 23 (15.3 net) wells in the first six months of 2015.

Divestiture activity during the first half of 2016 consisted of a non-core asset disposition in the Cardium business unit for proceeds of $1.3 million, minor non-core asset dispositions for proceeds of $0.2 million and adjustments to prior year dispositions of $0.1 million.

Decommissioning Liabilities

At June 30, 2016, the Company recorded decommissioning liabilities of $247.4 million (December 31, 2015 - $220.3 million). Decommissioning liabilities increased by $13.8 million in the second quarter of 2016, primarily as a result of the decrease in risk free discount rate from 2.0% at March 31, 2016 to 1.75% at June 30, 2016 and, to a lesser extent, accretion expense. Decommissioning liabilities increased by $27.1 million in the six months ended June 30, 2016, primarily as a result of the decrease in risk free discount rate from 2.25% at December 31, 2015 to 1.75% at June 30, 2016 and, to a lesser extent, accretion expense.

SUMMARY OF QUARTERLY RESULTS

	2016		2015				2014	
	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3
Financial ($000s except where noted)								
Total debt[1]	1,574,576	1,567,236	1,627,752	1,603,610	1,668,123	1,731,248	1,646,862	1,557,817
Capital expenditures[2]	7,504	7,353	11,925	14,217	20,175	60,254	121,124	90,164
Net capital expenditures[1]	6,216	7,071	13,353	14,437	18,324	48,931	123,194	(372,259)
Dividends[1]	—	—	—	—	—	—	19,247	24,370
Per share[1]	—	—	—	—	—	—	0.10	0.12
Payout ratio (%)[1]	—	—	—	—	—	—	22	19
Oil and natural gas sales	76,716	63,175	94,421	108,759	136,265	121,131	186,861	269,177
Net income (loss)	(709,469)	18,413	(342,153)	(425,588)	(51,533)	(126,741)	(532,560)	3,891
Per share – basic	(3.57)	0.09	(1.73)	(2.15)	(0.26)	(0.64)	(2.68)	0.02
Per share – diluted[3]	(3.57)	0.09	(1.73)	(2.15)	(0.26)	(0.64)	(2.68)	0.02
Adjusted net income (loss)[1]	110,502	27,076	27,847	6,621	(51,533)	(127,162)	160,386	6,935
Per share – basic[1]	0.56	0.14	0.14	0.03	(0.26)	(0.64)	0.81	0.03
Per share – diluted[1][3]	0.56	0.14	0.14	0.03	(0.26)	(0.64)	0.80	0.03
Funds flow from operations[1]	3,787	(10,610)	30,083	44,646	66,966	51,928	89,278	130,950
Per share – basic[1]	0.02	(0.05)	0.15	0.23	0.34	0.26	0.45	0.65
Per share – diluted[1][3]	0.02	(0.05)	0.15	0.23	0.34	0.26	0.44	0.64
Operations								
Oil equivalent sales price ($/boe)	33.56	26.35	36.32	39.07	46.84	38.26	55.69	75.34
Royalties	2.73	2.74	4.74	4.17	4.47	4.61	8.76	11.32
Production expenses	11.48	12.05	12.51	12.48	12.89	12.48	13.47	14.85
Transportation expenses	0.25	0.27	0.27	0.28	0.30	0.30	0.31	0.50
Operating netback[1]	19.10	11.29	18.80	22.14	29.18	20.87	33.15	48.67
Average daily production								
Crude oil and NGL's (bbls)	16,333	17,873	19,662	21,436	23,066	26,607	27,299	30,203
Natural gas (Mcf)	52,697	50,861	51,588	52,912	53,399	51,429	55,037	51,802
Total (boe)[4]	25,116	26,350	28,260	30,255	31,966	35,179	36,472	38,837

(1) Non-GAAP measure. See "Non-GAAP Measures" section within the MD&A.

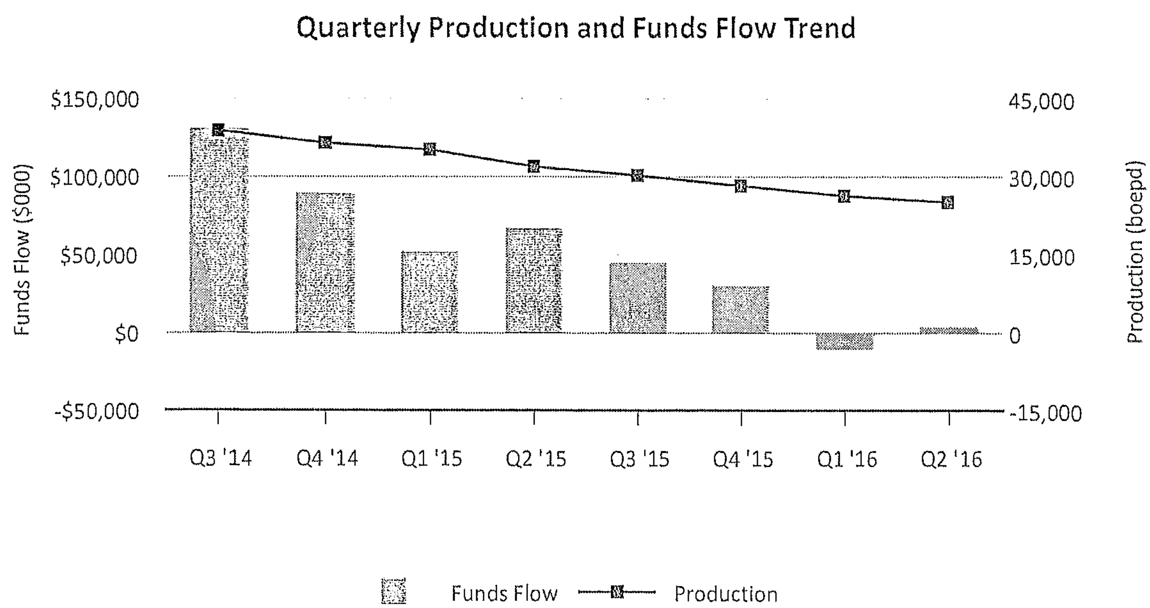
(2) Prior to asset acquisitions and dispositions.

(3) Includes common shares, stock options, deferred common shares and incentive shares on the same basis as net income. Prior to Q1 2016, convertible debentures have been included as at the period end date based on the stated conversion price as of that date.

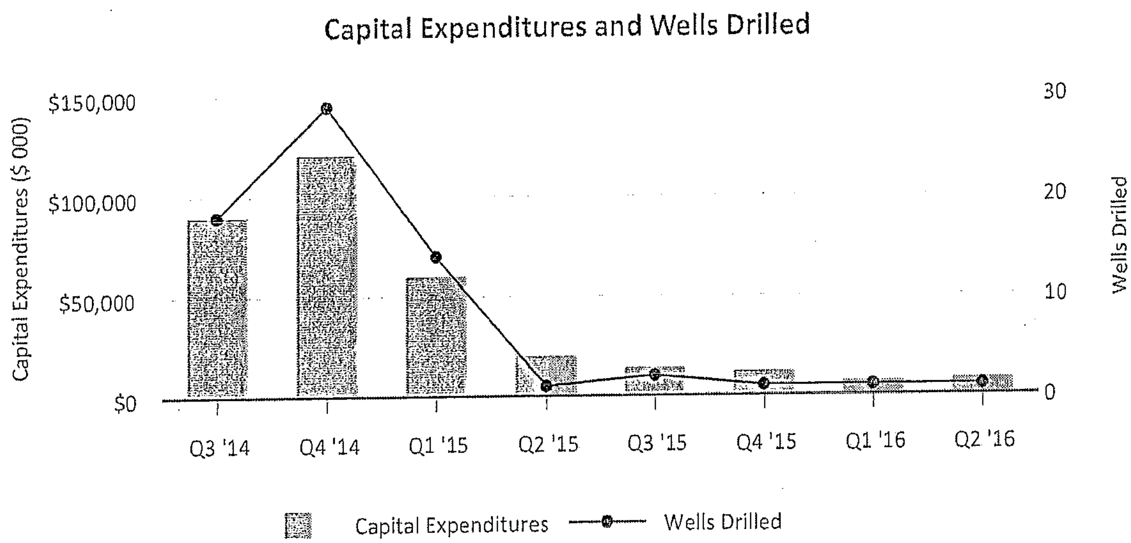
(4) Six Mcf of natural gas is equivalent to one barrel of oil equivalent.

Significant factors influencing quarterly results were:

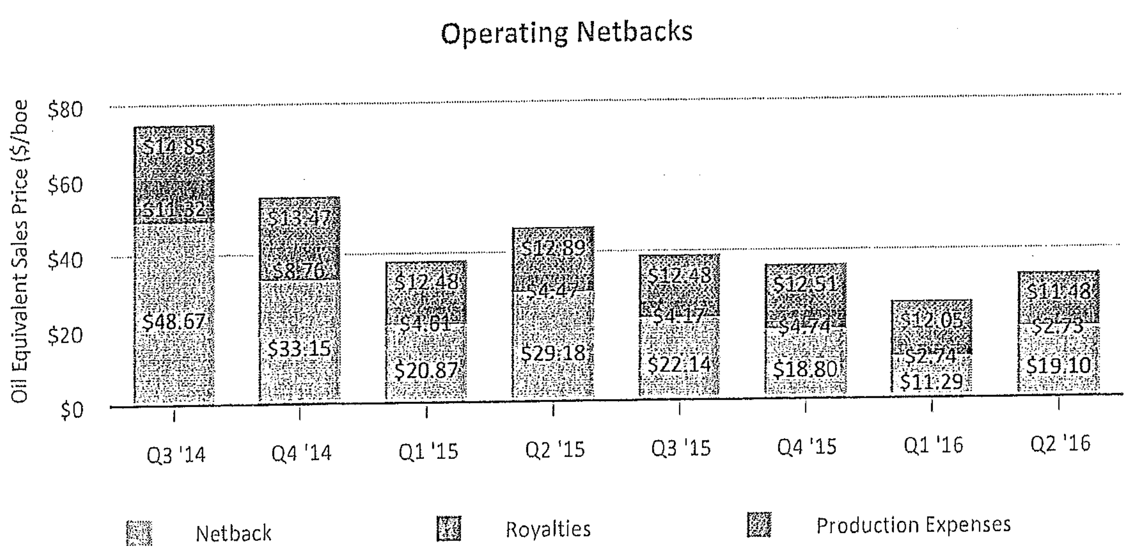
- Oil and natural gas sales have fluctuated over the past eight quarters primarily due to changes in $WTI benchmark prices and corporate oil price differentials applied to lower production levels.
- Net income (loss) has fluctuated primarily due to changes in funds flow from operations, unrealized derivative gains and losses, asset disposition gains and losses, unrealized foreign exchange gains and losses related to the Company's secured and unsecured debt and impairments.
- Production has trended downwards over the past eight quarters due to the execution of our 2014 divestiture plan and a reduction in the amount of capital spending on new wells. The attenuation in the level of capital spending over that time resulted in natural declines exceeding new production.
- Funds flow from operations is primarily impacted by variability in production levels and operating netback. Funds flow from operations has trended downwards since Q3 2014, both on a total dollar and per share basis, due to the decrease in production combined with lower operating netback, resulting primarily from significantly lower realized prices. The decrease in realized pricing is primarily driven by lower WTI prices, which decreased from an average of US$97.17/bbl in Q3 2014 to an average of US $33.52/bbl in Q1 2016, contributing to a funds flow deficit in the first quarter of 2016. Funds flow from operations was higher in Q2 2016 as WTI oil prices improved to an average of US$45.59/bbl in the second quarter.



- Capital expenditures and the number of wells drilled have trended downward since Q4 2014, which is indicative of the continuing downturn of this commodity price cycle. Capital expenditures of $7.5 million in Q2 2016 represented our second lowest spending quarter over the past eight quarters, where we drilled one (0.3 net) non-operated Cardium well.



- Our operating netback for Q2 2016 of $19.10/boe was higher than the previous two quarters, reflecting a slight rebound in oil prices over that period. Both royalties and production expenses continued to trend downward to levels that are the lowest compared to the previous seven quarters. Royalties per boe trended downward consistent with lower realized pricing and reduced revenues. Production expenses per boe trended lower due to reduced variable production costs, cost savings initiatives and the sale of assets with higher cost production in 2014.



COMMITMENTS

The following is a summary of the estimated costs required to fulfill the Company's remaining contractual commitments at June 30, 2016:

Type of commitment		1 Year		2-3 Years		4-5 Years		Thereafter		Total
Office leases (1)	$	3,800	$	11,489	$	3,863	$	—	$	19,152
Marketing commitments		6,055		9,913		850		3,238		20,056
Total (2)	$	9,855	$	21,402	$	4,713	$	3,238	$	39,208

(1) Includes sublease recoveries of $0.2 million (1 Year).
(2) Commitments do not include onerous contracts.

LIQUIDITY AND CAPITAL RESOURCES

On April 29, 2016, our Credit Facility semi-annual borrowing base re-determination was completed, resulting in a reduction to the borrowing base from $550 million to $250 million. At the time of the re-determination, the Company had $371 million outstanding under the Credit Facility including issued letters of credit. As a result of the Company's failure to make the June 15 semi-annual interest payment on its Secured Notes by July 15, 2016, the Company triggered defaults under the Credit Facility, the Secured Notes indenture and the Unsecured Notes indenture. In anticipation of this, and in connection with the Company's Recapitalization plan, the Company received a preliminary interim order from the Court of Queen's Bench of Alberta containing a stay prohibiting any person, including the holders of Secured Notes and holders of Unsecured Notes, other than the lenders under the Credit Facility, from terminating, making any demand, accelerating, amending or declaring in default or taking any enforcement steps under any contract or other agreement to which the Company is a party. On July 12, 2016, the Company also entered into a forbearance agreement with the lenders under the Credit Facility. Pursuant to the forbearance agreement, as amended, the lenders have agreed to forbear from exercising their enforcement rights and remedies arising on account of existing defaults under the Credit Facility until August 5, 2016, including in respect of the Company's hedging liabilities. The Company has requested and anticipates receiving an extension to the forbearance relief period to August 12, 2016, however there is no assurance the Company will obtain this extension. Subject to obtaining the forbearance extension and satisfactory commitments to provide the new revolving credit facility, the Company anticipates entering into a second forbearance agreement with the lenders prior to August 12, 2016 to extend the forbearance through the anticipated completion of the CBCA Plan and implementation of a new revolving credit facility.

On July 28, 2016, the Company entered into a definitive arrangement agreement with a new wholly-owned subsidiary to effect a series of transactions which will result in the Recapitalization. The proposed Recapitalization is intended to be implemented by way of a CBCA Plan. Under a support agreement entered into on July 12, 2016, the Initial Consenting Noteholders have agreed, subject to certain conditions, to vote their securities in favour of the CBCA Plan. In addition, in connection with the completion of the Recapitalization, we are working towards a replacement credit facility. The Recapitalization is expected to reduce the Company's overall debt by approximately US$904 million (Cdn$1.175 billion) in principal and reduce our cash interest payments by over US$83 million (Cdn$108 million) per year. The Company no longer has available borrowing capacity under the Credit Facility.

Future operations are dependent on the completion of the Recapitalization; the generation of positive cash flows from operations; the maintenance of existing reserve and production levels and the ability to discharge obligations as they come due. The completion of the Recapitalization is subject to a number of conditions, including that all required stakeholder, third-party, regulatory, court and stock exchange approvals, consents or waivers must have been received (or, in the case of waiting or suspensory periods, such waiting or suspensory periods shall have expired or terminated) and that Lightstream must have entered into an additional forbearance agreement with our lenders and replaced the Credit Facility with a new credit facility.

In the event that the requisite approvals in respect of the CBCA Plan are not obtained or the Company is otherwise unable to complete the CBCA Plan, the Company has agreed to pursue the Recapitalization through a sale transaction (the "CCAA Sale Transaction") that will be implemented through proceedings commenced under the Companies' Creditors Arrangement Act (the "CCAA"). As part of the proceedings under the CCAA, the Initial Consenting Noteholders will make (or direct) a credit bid (the "Secured Credit Bid") for the full amount of the claims outstanding in respect of the Secured Notes, which Secured Credit Bid may serve as a stalking horse transaction in a sale and investment solicitation process ("SISP"). To that end, on July 13, 2016, the Company initiated a SISP which is intended to generate interest in and potentially divest the business and/or the assets of the Company, with the goal of maximizing value for all stakeholders of the Company and identifying the best available transaction in the event that the CBCA Plan does not proceed.

A failure to complete the Recapitalization, either through the CBCA plan or the Secured Credit Bid under the CCAA, may cast significant doubt about the Company's ability to continue as a going concern.

The Credit Facility has a single covenant that limits the ratio of facility borrowing to trailing twelve month Adjusted EBITDA to:

January 1, 2015 - September 30, 2015 - 3.0x

October 1, 2015 - June 30, 2016 - 3.75x

July 1, 2016 - December 31, 2016 - 4.25x

January 1, 2017 - June 2, 2017 - 4.0x

The Company is in compliance with this covenant with a ratio of 1.82x at June 30, 2016.

At June 30, 2016, Lightstream had US$650 million of Secured Notes outstanding, which bear interest at 9.875% per annum and mature June 15, 2019. The Secured Notes are secured by second-priority liens on all of Lightstream's assets which rank behind the security under our Credit Facility. Pursuant to the terms of the Secured Notes indenture, the Company is permitted to issue a maximum of $750 million in first lien debt. The Secured Notes contain covenants that could limit the Company's ability to issue additional debt, pay dividends, and redeem equity or debt, among other restrictions. The Company is in default under the Secured Notes indenture as a result of the failure to make the June 15, 2016 semi-annual interest payment by July 15, 2016 which also constitutes an event of default under the Credit Facility and the Unsecured Notes indenture. Pursuant to the preliminary interim order from the Court of Queen's Bench of Alberta, the holders of Secured Notes are stayed from terminating, making any demand, accelerating, amending or declaring in default or taking any enforcement steps under the Secured Notes indenture.

At June 30, 2016, Lightstream had US$254 million of Unsecured Notes outstanding. The Unsecured Notes bear interest at a rate of 8.625% per annum and mature February 1, 2020. Pursuant to the terms of the Unsecured Notes indenture, the Company is permitted to issue a maximum of US$1.5 billion in first lien debt less secured debt outstanding. The Unsecured Notes contain covenants that could limit the Company's ability to issue additional debt, pay dividends, and redeem equity or debt, among other restrictions. The Company is in default under the Unsecured Notes indenture and has elected not to pay the August 2, 2016 semi-annual interest payment. Pursuant to the preliminary interim order from the Court of Queen's Bench of Alberta, the holders of Unsecured Notes are stayed from terminating, making any demand, accelerating, amending or declaring in default or taking any enforcement steps under the Unsecured Notes indenture.

During the first quarter of 2016, Lightstream settled US$4.5 million of outstanding convertible debentures that matured on February 8, 2016 for cash.

The Company is currently pursuing our Recapitalization plan in order to enhance liquidity. Under the plan the Company is seeking to:

- Convert or exchange Secured Notes and Unsecured Notes to equity, reducing interest expense by approximately $108 million per year;
- Establish exit financing credit agreements to provide $450 million of financing, which is in excess of the $371 million of obligations under the existing credit facility;
- Issue warrants that would potentially provide new funding of approximately $151 million if all warrants were exercised at the earliest date;

We currently expect to satisfy ongoing working capital requirements with cash on hand of $31.2 million (at June 30, 2016).

Capital Plan

First half 2016 expenditures of approximately $15 million were funded through our Adjusted EBITDA. Our first half 2016 capital plan was focused on capital maintenance projects, optimization and EOR initiatives to moderate our production declines. Due to the pending Recapitalization, the amount of discretionary development capital deployed during the second half of 2016 will be minimal as we remain committed to preserving the long-term value of our assets through the continuing low commodity price environment.

Dividends

The Company paid a monthly dividend of $0.04 per share or $0.48 per share per annum from January 2014 to November 2014, which was then reduced to $0.015 per share or $0.18 per share per annum for the month of December 2014. Subsequent to December 31, 2014, the dividend was suspended to help preserve the financial flexibility of the Company.

Outstanding Share Data

As at the date of this MD&A, there are 198.6 million Lightstream common shares outstanding, 0.6 million stock options, 7.9 million incentive shares and 0.5 million deferred common shares outstanding.

Risks and Uncertainties

The condensed consolidated financial statements as at and for the three and six months ended June 30, 2016 and 2015 have been prepared on the basis that the Company is a going concern under which the Company is assumed to be able to realize our assets and discharge our liabilities in the normal course of operations.

Future operations are dependent on the completion of the Recapitalization; the generation of positive cash flows from operations; the maintenance of existing reserve and production levels and the ability to discharge obligations as they come due. The Recapitalization is subject to a number of conditions described under "Liquidity and Capital Resources". A failure to complete the Recapitalization, either through the CBCA plan or the Secured Credit Bid under the CCAA, may cast significant doubt about the Company's ability to continue as a going concern.

Sensitivities

Lightstream's earnings and funds flow from operations are sensitive to changes in crude oil and natural gas prices, exchange rates and interest rates.

The following factors demonstrate the expected impact on annualized before-tax funds flow from operations excluding the effect of risk management activities impacting 2016:

Change of:		(millions)
Crude oil	US$1.00/bbl WTI reference price (assuming 16,300 boepd)[1]	**$6.2**
	1,000 bopd of production @ US$45.59/bbl WTI	**$15.2**
Natural gas	$0.10/Mcf AECO reference price (assuming 52 MMcf/d)	**$1.7**
	1.0 MMcf per day of production @ $1.40/Mcf AECO	**$0.3**
Currency	US$0.01 in exchange rate	**$1.8**
Interest rate	1% in interest rate (assuming $350 million of floating rate debt)	**$3.5**

(1) Includes the impact of oil and NGL price realization.

Critical Accounting Estimates

There have been no changes to the Company's critical accounting estimates in the three and six months ended June 30, 2016.

Changes in Accounting Policies

In April 2016, the IASB issued its final amendments to IFRS 15 Revenue from Contracts with Customers, which replaces IAS 18 Revenue, IAS 11 Construction Contracts, and related interpretations. The standard is required to be adopted either retrospectively or using a modified retrospective approach for annual periods beginning on or after January 1, 2018, with earlier adoption permitted. The Company will assess the impact of the standard on its financial statements.

Policies

Internal Control over Financial Reporting

Lightstream is required to comply with National Instrument 52-109 "Certification of Disclosure in Issuers' Annual and Interim Filings". The certification of interim filings for the interim period ended June 30, 2016 requires that Lightstream disclose in the interim MD&A any changes in Lightstream's internal control over financial reporting that occurred during the period that have materially affected, or are reasonably likely to materially affect, Lightstream's internal control over financial reporting. Lightstream confirms that no such changes were made to its internal controls over financial reporting during the three months ended June 30, 2016.

Non-GAAP Measures

Funds flow from operations, funds flow per share, adjusted net income, adjusted net income per share, dividends paid, dividends paid per share, payout ratio, adjusted EBITDA, total debt, operating netback, and net capital expenditures do not have standardized meanings and are therefore unlikely to be comparable to similar measures presented by other companies.

Funds flow from operations *reflects cash generated from operating activities from continuing operations before changes in non-cash working capital. Funds flow per share is calculated as funds flow from operations divided by the weighted average number of shares outstanding for the period.*

The following table reconciles cash flow from operating activities to funds flow from operations:

	Three months ended June 30,		Six Months Ended June 30,	
	2016	2015	**2016**	2015
Cash flow from operating activities	$ 26,636	$ 72,246	$ 39,776	$ 111,446
Adjustments:				
Changes in non-cash working capital	(22,849)	(5,280)	(46,599)	7,448
Funds flow from operations	$ 3,787	$ 66,966	$ (6,823)	$ 118,894
Weighted Average shares outstanding - basic	198,581	197,470	198,501	197,406
Weighted Average shares outstanding - diluted[(1)]	198,581	198,031	198,501	197,725

(1) Includes dilution impact of convertible debentures for the three and six months ended June 30, 2015.

Adjusted net income (loss) *is determined by adding back to net income (loss) from continuing operations any losses or deducting any gains on the derivative financial liability, adding back any losses or deducting any gains on settlement of convertible debentures, unsecured notes and secured notes, adding back losses on onerous contracts and adding back impairments. Adjusted net income (loss) per share is calculated as adjusted net income (loss) divided by the weighted average number of shares outstanding for the period.*

The following table reconciles net income (loss) to adjusted net income (loss):

	Three months ended June 30,		Six Months Ended June 30,	
	2016	2015	**2016**	2015
Net Income (loss)	$ (709,469)	$ (51,533)	$ (691,056)	$ (178,274)
Adjustments:				
Loss (gain) on derivative financial liability	—	—	—	(421)
Loss on onerous contracts	15,122	—	15,122	—
Impairments	804,849	—	813,512	—
Adjusted Net Income (loss)	$ 110,502	$ (51,533)	$ 137,578	$ (178,695)
Weighted Average shares outstanding - basic	198,581	197,470	198,501	197,406
Weighted Average shares outstanding - diluted	198,581	197,470	198,501	197,406

Dividends paid *are total declared dividends paid by Lightstream. Dividends paid per share reflect total declared dividends paid divided by the total shares outstanding.*

Payout ratio *is determined as declared dividends paid as a percentage of funds flow from operations.*

Management considers funds flow from operations, funds flow per share, adjusted net income, adjusted net income per share, dividends paid, dividends paid per share and payout ratio important as they help to evaluate performance and demonstrate the ability to generate sufficient cash to fund future growth opportunities, pay dividends and repay debt.

Adjusted EBITDA *is defined as earnings before interest, taxes, depletion and depreciation, and other non-cash items. This measure is used to evaluate compliance with certain financial covenants.*

Total debt *includes credit facility outstanding plus accounts payable less accounts receivable and prepaid expenses plus the full value outstanding on the Secured Notes, Unsecured Notes and convertible debentures converted to Canadian dollars at the exchange rate on the period end date less the value of long-term investments. Total debt is used to evaluate Lightstream's financial leverage.*

As at,	**June 30, 2016**	December 31, 2015	June 30, 2015
Secured termed credit facility	$ 359,000	$ 344,188	$ 625,958
Working capital deficiency:			
Accounts payable and accrued liabilities	116,976	86,040	130,738
Cash	(31,235)	—	—
Accounts receivable	(39,451)	(53,858)	(82,373)
Prepaid expenses	(6,211)	(5,563)	(9,150)
Secured Notes [1]	845,585	899,600	—
Unsecured Notes [1]	330,358	351,461	997,864
Convertible debentures [1]	—	6,228	5,613
Long-term investments	(446)	(344)	(527)
Total Debt	$ 1,574,576	$ 1,627,752	$ 1,668,123

(1) Converted using CDN$/US$ period end exchange rate of 0.77 at June 30, 2016 (December 31, 2015 - 0.72, June 30, 2015 - 0.79).

Operating netback *reflects revenues less royalties, production expenses and transportation costs divided by production for the period. Operating netback demonstrates profitability relative to commodity prices per unit of production.*

Net capital expenditures *represent capital expenditures from continuing operations, including exploration and evaluation expenditures and asset acquisitions, less proceeds from asset dispositions from continuing operations.*

Forward-Looking Statements

Certain information provided in this MD&A constitute forward-looking statements. The use of any of the words "expect", "anticipate", "continue", "estimate", "objective", "ongoing", "may", "will", "project", "should", "believe", "plans", "intends", "strategy", and similar expressions and statements relating to matters that are not historical facts constitute forward-looking information within the meaning of applicable Canadian securities legislation.

In particular, forward-looking statements include, but are not limited to: the proposed Recapitalization including the CBCA Plan and the matters related thereto, including the anticipated timing of certain events, the Company being able to receive all required court and regulatory approvals to consummate the CBCA Plan, the ability of the Company to obtain the required levels of approval from holders of Common Shares, Secured Notes and Unsecured Notes for the CBCA Plan, the ability of the parties to satisfy the other conditions to the CBCA Plan, the execution of a forbearance extension and second forbearance agreement with its lenders, the ability to enter into binding commitment letters for the new credit facility of the Company, and the size thereof, the potential and anticipated impact of the Recapitalization on Lightstream, the commencement of proceedings under the CCAA in the event that the CBCA Plan is not approved or otherwise does not occur, future capital structure, debt levels and annual interests costs, improved liquidity, release of guidance and anticipated timing, planned development capital spending and production levels for the remainder of 2016, the sufficiency of cash to fund ongoing operations, and our ability to meet or mitigate requirements under certain long-term contracts.

The forward-looking statements in this MD&A are based upon certain material factors and expectations and assumptions of Lightstream including, without limitation: that all necessary approvals to the completion of the Recapitalization, including the receipt of all required securityholder, court, exchange and regulatory approvals, as applicable, will be obtained in a timely manner, and that all parties involved in the Recapitalization will fulfill their obligations in connection therewith; the Company's ability to continue to obtain financing on acceptable terms; future oil and gas prices, interest rates and foreign exchange rates; future development and operating costs and royalty and taxation rates; that Lightstream will continue to conduct operations in a manner consistent with past operations; the general continuance of current industry conditions; the continuance of existing (and in certain circumstances, the implementation of proposed) tax, royalty and regulatory regimes, the accuracy of the estimates of Lightstream's reserves and resource volumes; certain commodity price and other cost assumptions; and the sufficiency of cash flow to fund our operations. Although Lightstream believes the material factors, expectations and assumptions on which the forward-looking statements are based are reasonable, no assurance can be given that these factors, expectations and assumptions will prove to be correct.

The forward-looking statements in this MD&A are not guarantees of future performance and should not be unduly relied upon. Such statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking statements including, but not limited to: that the Company may not be able to complete the Recapitalization, including the CBCA Plan, on the timeline or on the terms currently contemplated or at all, the Recapitalization may have an effect on the Company other than what is currently anticipated, the pursuit of the Recapitalization, CBCA Plan and related activities may divert management time and attention away from other business matters, that the Company's business is exposed to commodity price and exchange rate fluctuations and changes in the general conditions in the oil and gas industry and in general economic conditions, changes in commodity prices and exchange rates; general conditions in the oil and gas industry; operational risks; unanticipated operating results or production declines; changes in exploration or development plans; the uncertainty of oil and gas reserve *estimates; increase in costs; reliance on industry partners; availability of equipment and personnel; changes in tax or environmental laws, royalty rates or other regulatory matters; increased debt levels or debt service requirements; limited, unfavorable or lack of access to capital markets; a lack of adequate insurance coverage; the impact of competition; and certain other risks detailed from time to time in Lightstream's public disclosure documents (including, without limitation, those risks set out in more detail in this MD&A and in our Annual Information Form).*

The forward-looking statements contained in this MD&A speak only as of the date of this MD&A and, except as may be required by applicable securities laws, Lightstream assumes no obligation to publicly update or revise any forward-looking statements made herein or otherwise, whether as a result of new information, future events or otherwise.

Additional Information

Further information regarding Lightstream Resources Ltd., including our Annual Information Form, can be accessed under the Company's public filings found at www.sedar.com and on the Company's website at www.lightstreamresources.com.

CONDENSED CONSOLIDATED BALANCE SHEETS

(Unaudited, thousands of Canadian dollars)

As at,	Note	June 30, 2016	December 31, 2015
Assets			
Current assets			
Cash and cash equivalents		$ 31,235	$ —
Accounts receivable		39,451	53,858
Prepaid expenses		6,211	5,563
Risk management assets	18	517	9,732
		77,414	69,153
Long-term investments		446	344
Exploration and evaluation	7	168,553	271,970
Property, plant and equipment	8	1,433,137	2,217,405
Total assets		$ 1,679,550	$ 2,558,872
Liabilities and Equity			
Current liabilities			
Current portion of secured termed credit facility	9	$ 121,000	$ —
Accounts payable and accrued liabilities		116,976	86,040
Current portion of onerous contracts	13	4,370	—
Convertible debentures	11	—	6,164
Risk management liabilities	18	452	—
		242,798	92,204
Secured termed credit facility	9	234,429	340,832
Secured notes	10	845,585	899,600
Senior unsecured notes	12	325,390	345,565
Long-term portion of onerous contracts	13	10,752	—
Other long-term liabilities		5,721	6,335
Decommissioning liabilities	14	247,350	220,306
Deferred tax liabilities		—	197,377
		1,912,025	2,102,219
Shareholders' equity			
Shareholders' capital	15	2,371,313	2,368,272
Contributed surplus	15	159,792	160,905
Deficit		(2,763,580)	(2,072,524)
Total shareholders' equity		(232,475)	456,653
Total liabilities and equity		$ 1,679,550	$ 2,558,872

See accompanying notes to these condensed consolidated financial statements.

Approved by the Board of Directors

Kenneth McKinnon
Chairman of the Board of Directors

Corey C. Ruttan
Director

CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME (LOSS)

(Unaudited, thousands of Canadian dollars, except per share amounts)

	Note	Three months ended June 30, 2016	Three months ended June 30, 2015	Six months ended June 30, 2016	Six months ended June 30, 2015
Revenues					
Oil and natural gas sales		$ 76,716	$ 136,265	$ 139,891	$ 257,396
Royalties		(6,233)	(13,002)	(12,803)	(27,588)
Oil and natural gas revenues		70,483	123,263	127,088	229,808
(Loss) gain on risk management contracts	18	(4,707)	(17,283)	(2,109)	4,090
		65,776	105,980	124,979	233,898
Expenses					
Production		26,238	37,497	55,132	77,020
Transportation		579	872	1,229	1,806
General and administrative		7,630	9,491	17,329	22,438
Share-based compensation	15	1,386	2,083	1,912	3,494
Loss on onerous contracts	13	15,122	—	15,122	—
Loss (gain) on dispositions	8	675	(556)	310	1,332
Long-term investments (gain) loss		(53)	250	(94)	416
Interest and other	6	35,200	30,409	70,596	59,363
Foreign exchange (gain) loss		3,490	(16,351)	(73,985)	72,656
Depletion and depreciation expense	8	55,610	87,008	112,349	180,334
Impairment	7,8	804,849	—	813,512	—
		950,726	150,703	1,013,412	418,859
Loss before taxes		(884,950)	(44,723)	(888,433)	(184,961)
Income tax (recovery) expense		(175,481)	6,810	(197,377)	(6,687)
Net loss and comprehensive loss		$ (709,469)	$ (51,533)	$ (691,056)	$ (178,274)
Basic loss per share	16	$ (3.57)	$ (0.26)	$ (3.48)	$ (0.90)
Diluted loss per share	16	$ (3.57)	$ (0.26)	$ (3.48)	$ (0.90)

See accompanying notes to these condensed consolidated financial statements.

FINANCIAL STATEMENTS

CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY
(Unaudited, thousands of Canadian dollars)

	Common Shares	Contributed Surplus	Deficit	Total Shareholders' Equity
January 1, 2016	$ 2,368,272	$ 160,905	$ (2,072,524)	$ 456,653
Net loss	—	—	(691,056)	(691,056)
Issued under employee incentive plan	16	—	—	16
Share-based compensation	—	1,912	—	1,912
Share-based settlements	3,025	(3,025)	—	—
June 30, 2016	**$ 2,371,313**	**$ 159,792**	**$ (2,763,580)**	**$ (232,475)**

	Common Shares	Contributed Surplus	Deficit	Total Shareholders' Equity
January 1, 2015	$ 2,358,361	$ 164,619	$ (1,126,509)	$ 1,396,471
Net loss	—	—	(178,274)	(178,274)
Issued under employee incentive plan	13	—	—	13
Share-based compensation	—	3,494	—	3,494
Share-based settlements	3,027	(3,027)	—	—
June 30, 2015	**$ 2,361,401**	**$ 165,086**	**$ (1,304,783)**	**$ 1,221,704**

See accompanying notes to these condensed consolidated financial statements.

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOW

(Unaudited, thousands of Canadian dollars)

	Note	Three months ended June 30, 2016	Three months ended June 30, 2015	Six months ended June 30, 2016	Six months ended June 30, 2015
Operating Activities					
Net loss		$ (709,469)	$ (51,533)	$ (691,056)	$ (178,274)
Adjusted for:					
Impairment	7,8	804,849	—	813,512	—
Loss on onerous contracts	13	15,122	—	15,122	—
Depletion and depreciation	8	55,610	87,008	112,349	180,334
Income tax (recovery) expense		(175,481)	6,810	(197,377)	(6,687)
Unrealized loss (gain) on risk management contracts	18	6,001	36,750	9,667	45,219
Unrealized foreign exchange (gain) loss		3,422	(16,474)	(74,795)	69,005
Share-based compensation	15	1,386	2,083	1,912	3,494
(Gain) loss on dispositions	8	675	(556)	310	1,332
Unrealized (gain) loss on long-term investments		(53)	250	(94)	416
Non-cash interest and other	6	1,897	2,626	4,022	4,594
Decommissioning liabilities settled	14	(172)	2	(395)	(539)
		3,787	66,966	(6,823)	118,894
Changes in non-cash working capital	19	22,849	5,280	46,599	(7,448)
		26,636	72,246	39,776	111,446
Investing Activities					
Expenditures on property, plant, and equipment	8	(7,504)	(20,240)	(14,851)	(80,393)
Exploration and evaluation expenditures	7	—	(19)	(6)	(120)
Proceeds from dispositions, net of adjustments	8	1,288	1,935	1,570	13,258
Purchase of long-term investments		(4)	385	(8)	385
Changes in non-cash working capital	19	(820)	(40,461)	(2,471)	(90,851)
		(7,040)	(58,400)	(15,766)	(157,721)
Financing Activities					
Issuance of shares	15	7	9	16	13
Issuance of secured termed credit facility, net of costs	9	11,652	(13,802)	13,433	51,936
Repurchase of convertible debentures	11	—	—	(6,177)	(2,007)
Changes in non-cash working capital	19	(20)	(53)	(47)	(3,667)
		11,639	(13,846)	7,225	46,275
Net change in cash and cash equivalents		31,235	—	31,235	—
Cash and cash equivalents, beginning of period		—	—	—	—
Cash and cash equivalents, end of period		$ 31,235	$ —	$ 31,235	$ —
Other cash flow information					
Cash interest paid		$ 5,571	$ 27,783	$ 9,235	$ 54,769

See accompanying notes to these condensed consolidated financial statements.

Note 1 – Corporate Information and Proposed Recapitalization

Lightstream Resources Ltd. ("Lightstream" or the "Company") is an Alberta corporation with shares listed on the Toronto Stock Exchange ("TSX"). The records office and principal address are located at 2800, 525-8th Avenue SW, Calgary, Alberta T2P 1G1.

The Company is principally engaged in the exploration and development of oil and natural gas in western Canada.

Proposed Recapitalization Plan

On July 28, 2016, the Company entered into a definitive arrangement agreement with our wholly-owned subsidiary to effect a series of transactions which will result in the recapitalization (the "Recapitalization") of the Company's Secured Notes, the Company's US$254 million 8.625% unsecured notes due February 1, 2020 (the "Unsecured Notes") and the Company's common shares (the "Common Shares"). The proposed Recapitalization is intended to be implemented by way of a corporate plan of arrangement under the Canada Business Corporations Act (the "CBCA Plan"). Under a support agreement entered into on July 12, 2016, holders of 91.5% of the Company's Secured Notes (the "Initial Consenting Noteholders") have agreed, subject to certain conditions, to vote their securities in favour of the CBCA Plan. In addition, in connection with the completion of the Recapitalization, the Company is working towards a replacement credit facility for the Company's existing revolving credit facility (the "Credit Facility").

The features of the proposed CBCA Plan include the settlement of approximately US$904 million of the Company's debt in exchange for Common Shares of Lightstream with the following key elements:

- The existing Common Shares will be consolidated and new Common Shares ("New Common Shares") will be issued (using a ratio of approximately 88.29:1), with the result that approximately 100 million New Common Shares will be outstanding;
- Existing Shareholders will hold a total of 2.25% of the New Common Shares and existing Shareholders will receive Series 2 warrants equal to 7.75% of the total number of issued New Common Shares;
- The Secured Noteholders will hold a total of 95% of the New Common Shares in full and final satisfaction of their Secured Notes and claims in connection therewith;
- The Unsecured Noteholders will hold a total of 2.75% of the New Common Shares in addition to Series 1 warrants equal to 5% of the total number of issued New Common Shares in full and final satisfaction of their Unsecured Notes and claims in connection therewith.

As part of the CBCA Plan, on July 13, 2016, the Company received a preliminary interim order from the Court of Queen's Bench of Alberta containing a stay prohibiting any person, including the holders of Secured Notes and holders of Unsecured Notes, other than the lenders under the Credit Facility, from terminating, making any demand, accelerating, amending or declaring in default or taking any enforcement steps under any contract or other agreement to which the Company is a party. On July 12, 2016, the Company also entered into a forbearance agreement with the lenders under the Credit Facility. Pursuant to the forbearance agreement, as amended, the lenders agreed to forbear from exercising their enforcement rights and remedies arising on account of existing defaults under the Credit Facility until August 5, 2016, including in respect of the Company's hedging liabilities. The Company has requested and anticipates receiving an extension to the forbearance relief period to August 12, 2016, however there is no assurance the Company will obtain this extension.

Subject to obtaining the forbearance extension and satisfactory commitments for a new revolving credit facility, the Company anticipates entering into a second forbearance agreement with the lenders prior to August 12, 2016 to extend the forbearance through the anticipated completion of the CBCA Plan and implementation of the new revolving credit facility.

The completion of the Recapitalization is subject to a number of conditions, including that all required stakeholder, third-party, regulatory, court and stock exchange approvals, consents or waivers must have been received (or, in the case of waiting or suspensory periods, such waiting or suspensory periods shall have expired or terminated) and that Lightstream must have entered into an additional forbearance agreement with our lenders and replaced the Credit Facility with a new credit facility.

In the event that the requisite approvals in respect of the CBCA Plan are not obtained or the Company is otherwise unable to complete the CBCA Plan, the Company has agreed to pursue the Recapitalization through a sale transaction (the "CCAA Sale Transaction") that will be implemented through proceedings commenced under the Companies' Creditors Arrangement Act (the "CCAA"). As part of the proceedings under the CCAA, the Initial Consenting Noteholders will make (or direct) a credit bid (the "Secured Credit Bid") for the full amount of the claims outstanding in respect of the Secured Notes, which Secured Credit Bid may serve as a stalking horse transaction in a sale and investment solicitation process ("SISP"). To that end, on July 13, 2016, the Company initiated a SISP which is intended to generate interest in and potentially divest the business and/or the assets of the Company, with the goal of maximizing value for all stakeholders of the Company and identifying the best available transaction in the event that the CBCA Plan does not proceed.

The completion of the CBCA Plan is expected to result in a change of control for the Company which will result in automatic vesting of stock options, incentive shares and deferred common shares. All incentive shares and deferred common shares under Lightstream's employee incentive plans will be adjusted to reflect the capital reorganization contemplated by the CBCA Plan and will have a maximum term of six months following completion of the Recapitalization. All outstanding stock options will be repurchased for nominal consideration. There is not expected to be an impact on employee agreements assuming implementation of the CBCA Plan.

On June 14, 2016, the Company determined that it would not make the interest payment in the amount of US $32.1 million (approximately CDN$41.7 million) on the Secured Notes on June 15, 2016. Under the Indenture governing the Secured Notes, the Company had a 30-day grace period to make such payment. As the Company failed to make the required interest payment on July 15, 2016, there was an event of default under the Secured Notes Indenture, which in turn caused a cross default under the Credit Facility and the indenture governing the Unsecured Notes. The commencement of proceedings under the CBCA Plan was also a cross default under the Credit Facility and a cross default under the Unsecured Notes Indenture. Upon the occurrence of a cross default under the Credit Facility, all obligations owing under the Credit Facility, together with unpaid interest accrued thereon become due and immediately payable. Subsequent to June 30, 2016, the secured termed Credit Facility, Secured Notes and Senior Unsecured Notes will be reclassified as current liabilities should the CBCA Plan not materialize.

Note 2 - Going Concern

As a result of the Company's failure to make the June 15 semi-annual interest payment on its Secured Notes by July 15, 2016, the Company triggered defaults under the Credit Facility, the Secured Notes indenture and the Unsecured Notes indenture. In anticipation of this, and in connection with the Company's Recapitalization plan, the Company received a preliminary interim order from the Court of Queen's Bench of Alberta containing a stay prohibiting any person, including the holders of Secured Notes and holders of Unsecured Notes, other than the lenders under the Credit Facility, from terminating, making any demand, accelerating, amending or declaring in default or taking any enforcement steps under any contract or other agreement to which the Company is a party. On July 12, 2016, the Company also entered into a forbearance agreement with the lenders under the Credit Facility. Pursuant to the forbearance agreement, as amended, the lenders agreed to forbear from exercising their enforcement rights and remedies arising on account of existing defaults under the Credit Facility until August 5, 2016, including in respect of the Company's hedging liabilities. The Company has requested and anticipates receiving an extension to the forbearance relief period to August 12, 2016, however there is no assurance the Company will obtain this extension.

Subject to obtaining the forbearance extension and satisfactory commitments to provide the new revolving credit facility, the Company anticipates entering into a second forbearance agreement with the lenders prior to August 12, 2016 to extend the forbearance through the anticipated completion of the CBCA Plan and implementation of a new revolving credit facility.

Future operations are dependent on the completion of the Recapitalization; the generation of positive cash flows from operations; the maintenance of existing reserve and production bases and the ability to discharge obligations as they come due. The completion of the Recapitalization is subject to a number of conditions, including that all required stakeholder, third-party, regulatory, court and stock exchange approvals, consents or waivers must have been received (or, in the case of waiting or suspensory periods, such waiting or suspensory periods shall have expired or terminated) and that Lightstream must have entered into an additional forbearance agreement with our lenders and replaced the Credit Facility with a new credit facility. The Company is currently defending claims from certain Senior Unsecured Noteholders challenging the Company's exchange in 2015 of a portion of the Senior Unsecured Notes outstanding for newly issued Secured Notes (Note 10). The Company believes these claims are without merit. The plaintiffs have indicated that their holdings represent over 33 1/3 percent of the Senior Unsecured Notes outstanding. In order to be effective, the Recapitalization will require, among other things, the approval of Senior Unsecured Noteholders holding 66 2/3 percent of Senior Unsecured Notes outstanding voting on the resolution. These conditions cause significant doubt about the Company's ability to continue as a going concern.

These financial statements have been prepared on a going concern basis, which asserts the Company has the ability to continue to realize its assets and discharge its liabilities and commitments in a planned manner giving consideration to the above and expected possible outcomes. Conversely, if the going concern assumption is not appropriate, adjustments to the carrying amounts of the Company's assets, liabilities, revenues, expenses and balance sheet classifications may be necessary.

Note 3 - Basis of Presentation and Statement of Compliance

The condensed consolidated financial statements of the Company as at June 30, 2016 and for the three and six months ended June 30, 2016 and 2015 are condensed as they do not include all of the information required by IFRS for annual financial statements and therefore should be read in conjunction with Lightstream's audited consolidated financial statements as at and for the year ended December 31, 2015. The condensed consolidated financial statements are prepared using the same accounting policies and methods of computation as disclosed in the annual consolidated financial statements.

The condensed consolidated financial statements are stated in Canadian dollars and have been prepared in accordance with International Financial Reporting Standards ("IFRS") applicable to the presentation of interim financial statements and in accordance with International Accounting Standards ("IAS") 34 *Interim Financial Reporting.*

These condensed consolidated financial statements were authorized for issue by the Board of Directors on August 4, 2016.

Note 4 – Significant Accounting Policies

Use of Estimates and Judgments

The preparation of financial statements in accordance with IFRS requires management to make estimates, assumptions, and judgments that affect the reported amounts of assets and liabilities, amounts of revenues, expenses, and cash flows during the periods presented. Such estimates relate primarily to unsettled transactions and events as of the date of the financial statements. Actual results could differ materially from estimated amounts. Management reviews estimates and underlying assumptions on an ongoing basis.

Amounts recorded for onerous contracts are based on a number of factors including judgements whether or not a present obligation is probable. Onerous contract provisions are recognized where the unavoidable costs of meeting the obligations under a contract exceed the economic benefits expected to be received under it. Estimation of costs relating to onerous contract provisions is subject to measurement uncertainty.

Impairment calculations are based on a number of factors including estimates of fair value less costs to sell. The estimate of fair value of the Company's assets is subject to measurement uncertainty. To test impairment, costs are allocated into cash generating units ("CGU's") based on reserve cash flows. The determination of CGU's is subject to judgment.

Note 5 – Changes in Accounting Policies

Future Accounting pronouncements

In April 2016, the IASB issued its final amendments to IFRS 15 *Revenue from Contracts with Customers*, which replaces IAS 18 *Revenue*, IAS 11 *Construction Contracts*, and related interpretations. The standard is required to be adopted either retrospectively or using a modified retrospective approach for annual periods beginning on or after January 1, 2018, with earlier adoption permitted. The Company will assess the impact of the standard on its financial statements.

(Unaudited, all tabular amounts are expressed in thousands of Canadian dollars unless otherwise noted)

Note 6 – Interest and Other

The interest and other costs for the Company are as follows:

	Three months ended June 30, 2016	2015	Six months ended June 30, 2016	2015
Interest on secured notes	$ 20,677	$ —	$ 42,739	$ —
Interest on unsecured termed debt [1]	7,055	21,309	14,600	42,790
Interest on secured termed credit facility and other	5,571	6,474	9,235	11,979
Cash interest and other	33,303	27,783	66,574	54,769
Accretion on unsecured termed debt	287	850	618	1,698
Accretion on decommissioning liability	1,025	1,317	2,240	2,465
Amortization of deferred financing costs	585	459	1,164	852
Other [2]	—	—	—	(421)
Total interest and other	$ 35,200	$ 30,409	$ 70,596	$ 59,363

(1) Unsecured termed debt consists of senior unsecured notes and convertible debentures.
(2) Other comprised of gain on retirement of unsecured termed debt and gain on deferred financial liability.

Note 7 – Exploration and Evaluation Assets

As at,	June 30, 2016	December 31, 2015
Exploration and evaluation assets, beginning of period	$ 271,970	$ 335,837
Additions	6	385
Dispositions	—	(11,795)
Transfers to property, plant and equipment	(7,693)	(47,007)
Impairment	(95,730)	(5,450)
Exploration and evaluation assets, end of period	$ 168,553	$ 271,970

The Company performed an assessment of impairment at the time of transfer of assets from exploration and evaluation to property, plant and equipment. For the three and six months ended June 30, 2016, impairment expense of $15.0 million and $23.7 million (December 31, 2015 - $5.5 million) was recognized. Additional impairment expense of $72.0 million was recognized as part of the Property, Plant and Equipment impairment test. Refer to Note 8 for details.

(Unaudited, all tabular amounts are expressed in thousands of Canadian dollars unless otherwise noted)

Note 8 – Property, Plant and Equipment

	Oil and Natural Gas Assets	Other (1)	Total
Balance as at December 31, 2015	$ 2,212,554	$ 4,851	$ 2,217,405
Cost			
As at January 1, 2016	$ 6,418,050	$ 43,636	$ 6,461,686
Additions (2)	40,420	37	40,457
Dispositions	(4,398)	—	(4,398)
Transfers from exploration and evaluation assets	7,693	—	7,693
As at June 30, 2016	$ 6,461,765	$ 43,673	$ 6,505,438
Depletion and Depreciation			
As at January 1, 2016	$ 4,205,496	$ 38,785	$ 4,244,281
Charge for the period	110,789	1,560	112,349
Dispositions	(2,111)	—	(2,111)
Impairment	714,454	3,328	717,782
As at June 30, 2016	$ 5,028,628	$ 43,673	$ 5,072,301
Balance as at June 30, 2016	$ 1,433,137	$ —	$ 1,433,137

(1) Other fixed assets are mainly comprised of office furniture and fixtures, and computer equipment.
(2) Comprised of capital expenditures of $14.8 million and asset retirement costs of $25.6 million (See Note 14).

Asset dispositions

During the three months ended June 30, 2016, the Company disposed of non-core assets for net proceeds of $1.3 million (2015 - $1.9 million) and recognized a loss on dispositions of $0.7 million (2015 - $0.6 million gain), net of decommissioning liabilities disposed of $0.3 million (2015 - $0.1 million).

During the six months ended June 30, 2016, the Company disposed of non-core assets for net proceeds of $1.6 million (2015 - $13.2 million) and recognized a loss on dispositions of $0.3 million (2015 - $1.3 million loss), net of decommissioning liabilities disposed of $0.4 million (2015 - $0.1 million).

Impairment

The Company performs impairment tests when events and/or circumstances indicate that the carrying value of an asset or cash generating unit ("CGU") may exceed the recoverable amount. On July 12, 2016, the Company entered into a restructuring support arrangement in respect of the Recapitalization. A potential outcome of this plan is the Company having to sell assets during a depressed commodity environment which could reduce the recoverable amount of the Company's assets. As a result of the Recapitalization, impairment tests were performed at June 30, 2016.

Lightstream compared the carrying value of PP&E and E&E, adjusted for decommissioning liabilities, to the fair value of its assets. Where carrying value exceeded fair value, impairment expense was recognized. At December 31, 2015, the Company recognized an impairment expense primarily due to declining current and forecasted commodity prices for crude oil and natural gas.

(Unaudited, all tabular amounts are expressed in thousands of Canadian dollars unless otherwise noted)

In estimating the recoverable amount of PP&E and E&E at June 30, 2016, the Company considered various valuation options of the Company's total assets including valuations from the following sources:

- Post CBCA Plan external analyst valuation; and
- Secured Credit Bid amount pursuant to the CCAA Sale Transaction.

The external analyst valuation methodology would be one appropriate data point to consider in assessing the asset value upon a successful completion of the CBCA Plan. An unsuccessful completion of the CBCA Plan would result in a CCAA Sale Transaction with a Secured Credit Bid, which provides a valuation of the Company's assets. In assessing the fair value between the two scenarios, the Company considered the market metrics as well as market transactions that were completed in the last 18 months. The Company has entered into an agreement with the Initial Consenting Noteholders to support a Secured Credit Bid with a valuation of $1.3 billion (net of decommissioning liabilities) and as a result this represents a value the Company has agreed to sell the assets for and is presently the most appropriate valuation of estimated recoverable amount.

The estimated recoverable amounts were based on fair value less costs to sell calculations, which are classified as Level 3 fair value measurements as certain key assumptions are not based on observable market data but rather management's best estimates. Refer to Note 18 for information on fair value hierarchy classifications.

The Company used the weighting of proved plus probable ("2P") 10% strip futures pricing cash flow reserve values to allocate the estimated fair values of the Bakken CGU, Cardium CGU and Other Alberta CGU. The Company did not attribute a value to the British Columbia CGU as minimal reserves were assigned. The corporate and other assets are estimated to have no residual recoverable amounts, therefore no value was attributed to them.

The impairment tests indicated that the carrying value of the Company's Bakken CGU, Cardium CGU, Other Alberta CGU, and corporate and other assets exceeded the estimated recoverable amounts. Consequently, for the three months ended June 30, 2016, the Company recorded impairment expense totaling $789.8 million based on the difference between the carrying value at June 30, 2016 and the estimated recoverable amount. The impairment expense was allocated to the PP&E and E&E assets on a pro rata basis using the carrying value of the assets at June 30, 2016.

The following table depicts the impairment expense by CGU and the estimated recoverable amount:

As at June 30, 2016	Estimated recoverable amount	E&E Impairment expense	PP&E Impairment expense	Total Impairment expense (1)
Bakken CGU	$ 632,000	$ 45,900	$ 357,600	$ 403,500
Cardium CGU	606,500	21,900	341,000	362,900
Other Alberta CGU	116,500	4,200	9,900	14,100
Corporate & other assets (2)	—	—	9,300	9,300
Total	**$ 1,355,000**	**$ 72,000**	**$ 717,800**	**$ 789,800**

(1) Impairment expense does not include $23.7 million of impairment booked on transfer of assets from E&E to PP&E for a total impairment expense of $813.5 million for the six months ended June 30, 2016.

(2) Expense of $9.3 million includes an impairment on other assets of $3.3 million and an impairment of $6.0 million relating to the Company's corporate assets consisting of oil and gas equipment.

The successful implementation of the CBCA Plan could result in a higher estimated recoverable amount as the Company would not be required to dispose of the assets in a depressed commodity price environment. However, if the CBCA Plan is not implemented and the Initial Consenting Noteholders do not proceed with the Secured Credit Bid, there is no assurance that the Company will be able to obtain a similar offer for the assets which may indicate a lower recoverable amount.

Note 9 – Secured Termed Credit Facility

The Company has a first priority secured termed credit facility ("Credit Facility") which provides for a borrowing base at June 30, 2016 in the amount of $250 million (December 31, 2015 - $550 million), maturing on June 2, 2017, subject to further extension. The lending amount available under the Credit Facility is subject to semi-annual borrowing base re-determinations on October 31 and April 30 of each year. During the term of the Credit Facility, the Company will not pay cash dividends without the unanimous consent of the lenders.

On April 29, 2016, the Company's Credit Facility semi-annual borrowing base re-determination was completed resulting in a reduction of the borrowing base from $550 million to $250 million. As of the date of this report, the Company has $371 million outstanding under the Credit Facility including issued letters of credit. As a result, the Company no longer has available borrowing capacity under the Credit Facility.

As a result of the Company's failure to make the June 15 semi-annual interest payment on its Secured Notes by July 15, 2016, the Company triggered a cross-default under the Credit Agreement. In anticipation of this, on July 12, 2016, the Company entered into a forbearance agreement with the lenders under the Credit Facility. Pursuant to the forbearance agreement, as amended, the lenders agreed to forbear from exercising their enforcement rights and remedies arising on account of existing defaults under the Credit Facility until August 5, 2016, including in respect of the Company's hedging liabilities. The Company has requested and anticipates receiving an extension to the forbearance relief period to August 12, 2016, however there is no assurance the company will obtain this extension. Subject to its obtaining the forbearance extension and satisfactory commitments to provide the new revolving credit facility, the Company anticipates entering into a second forbearance agreement with the lenders prior to August 12, 2016 to extend the forbearance through the anticipated completion of the CBCA Plan and implementation of a new revolving credit facility.

The Credit Facility has a single financial covenant that limits the ratio of facility borrowing to trailing twelve months earnings before interest, taxes and other non-cash items ("Adjusted EBITDA") to:

January 1, 2015 - September 30, 2015 - 3.0x
October 1, 2015 - June 30, 2016 - 3.75x
July 1, 2016 - December 31, 2016 - 4.25x
January 1, 2017 - June 2, 2017 - 4.0x

The Company is in compliance with the financial covenant on the Credit Facility at June 30, 2016.
Refer to Note 1 and Note 17 for details.

(Unaudited, all tabular amounts are expressed in thousands of Canadian dollars unless otherwise noted)

The following table summarizes the balance of the Credit Facility:

As at,	June 30, 2016	December 31, 2015
Current portion of secured termed credit facility	$ 121,000	$ —
Long-term portion of secured termed credit facility	238,000	344,188
Secured termed credit facility outstanding	359,000	344,188
Deferred financing costs	(3,571)	(3,356)
Secured termed credit facility	$ 355,429	$ 340,832
Cash and cash equivalents	$ 31,235	$ —

The Company had letters of credit issued to third parties totaling $11.9 million (December 31, 2015 - $11.1 million), which reduce the borrowing capacity under the Credit Facility.

The Company had cash on hand of $31.2 million at June 30, 2016 and expects to be able to continue with base operations during the forbearance period.

Note 10 – Secured Notes

The Company had US$650 million of Second Lien Notes ("Secured Notes") outstanding at June 30, 2016 (December 31, 2015 - US$650 million).

The Secured Notes include the following terms:

Interest is payable semi-annually on June 15 and December 15, at an annual rate of 9.875%. The Secured Notes are secured by second priority liens on all of the Company's assets and are subordinate to indebtedness under the Credit Facility.

The Secured Notes mature on June 15, 2019. Subject to certain exceptions, Lightstream has the option to redeem the Secured Notes beginning on June 15, 2016 at the following redemption prices (expressed as a percentage of the principal amount plus accrued and unpaid interest):

June 15, 2016 - June 14, 2017 - 107.410%

June 15, 2017 - June 14, 2018 - 104.940%

June 15, 2018 and thereafter - 100%

On June 14, 2016, the Company announced that it had elected to defer the US$32.1 million semi-annual interest payment due June 15, 2016. As a result of the Company's failure to make the June 15 semi-annual interest payment on its Secured Notes by July 15, 2016, the Company triggered defaults under the Secured Notes indenture. In anticipation of this, on July 13, 2016, the Company obtained a preliminary interim order from the Court of Queen's Bench of Alberta initiating the proceedings under the CBCA Plan. The preliminary interim order includes a stay prohibiting any person, including the Secured Noteholders, from terminating, making any demand, accelerating, amending or declaring in default or taking any enforcement steps under any contract or agreement to which the Company is a party. The stay is effective until August 12, 2016 and the Company intends to seek a further stay prior to August 12, 2016 to complete the CBCA Plan.

The deferred interest payment of $US32.1 million (approximately CAD $41.7 million) is included in accounts payable and accrued liabilities at June 30, 2016.

(Unaudited, all tabular amounts are expressed in thousands of Canadian dollars unless otherwise noted)

The Company has certain restrictive financial covenants on its Secured Notes. There are no maintenance financial covenants on these notes. Refer to Note 1 and Note 17 for details. Changes to Secured Notes were as follows:

As at,	June 30, 2016	December 31, 2015
Secured Notes, beginning of period	$ 899,600	$ —
Issuance of senior secured notes (1)	—	823,513
Changes in exchange rate	(54,015)	76,087
Secured Notes, end of period	$ 845,585	$ 899,600

(1) 2015 includes issuance of $255,297 for cash proceeds and $568,216 in exchange for Unsecured Notes, excluding transaction costs, which were cancelled.

Note 11 - Convertible Debentures

On February 8, 2016, US$4.5 million of convertible debentures matured and were settled in cash. At June 30, 2016 no convertible debentures were outstanding (December 31, 2015 - US$4.5 million).

Note 12 – Senior Unsecured Notes

The Company had US$254 million of Senior Unsecured Notes ("Unsecured Notes") outstanding at June 30, 2016 (December 31, 2015 - US$254 million). The Unsecured Notes bear interest at a rate of 8.625% per annum payable semi-annually on August 1 and February 1, and mature on February 1, 2020. The Unsecured Notes are subordinate to indebtedness under Lightstream's Credit Facility and Secured Notes.

The Company elected not to make the interest payment on the Unsecured Notes on August 2, 2016.

As a result of the Company's failure to make the June 15 semi-annual interest payment on its Secured Notes by July 15, 2016, the Company triggered a cross-default under the Unsecured Notes indenture. In anticipation of this, on July 13, 2016, the Company obtained a preliminary interim order from the Court of Queen's Bench of Alberta initiating the proceedings under the CBCA Plan. The preliminary interim order includes a stay prohibiting any person, including the Unsecured Noteholders, from terminating, making any demand, accelerating, amending or declaring in default or taking any enforcement steps under any contract or agreement to which the Company is a party. The stay is effective until August 12, 2016 and the Company intends to seek a further stay prior to August 12, 2016 to complete the CBCA Plan.

The Company has certain restrictive financial covenants on its Unsecured Notes. There are no maintenance financial covenants on these notes. Refer to Note 1 and Note 17 for details.

The following table summarizes the Unsecured Notes:

As at,	June 30, 2016	December 31, 2015
Unsecured Notes, beginning of period	$ 345,565	$ 909,402
Repurchase of unsecured notes, inclusive of costs (1)	—	(575,120)
Gain on repurchase	—	(102,791)
Accretion	587	2,174
Changes in exchange rate	(20,762)	111,900
Unsecured Notes, end of period	$ 325,390	$ 345,565

(1) Repurchase inclusive of $6.9 million of transaction costs.

(Unaudited, all tabular amounts are expressed in thousands of Canadian dollars unless otherwise noted)

Note 13 – Onerous Contracts

Onerous contracts of the Company are as follows:

As at,	June 30, 2016	December 31, 2015
Current portion of onerous contracts	$ 4,370	$ —
Long-term portion of onerous contracts	10,752	—
Total onerous contracts	$ 15,122	$ —

Lease commitments

An onerous contract provision of $9.8 million has been recognized to account for vacant property that the Company is leasing. The onerous contract was calculated using present value of the future net lease commitments at a risk adjusted discount rate of 12% over the next six years.

Marketing commitments

An onerous contract provision of $5.3 million has been recognized to account for the Company's Marketing pipeline commitments, which require the Company to meet committed volumes under the agreement. Based on current industry conditions, the Company anticipates that it will not be able to meet all the volume requirements under the agreement which ends in July 2019. The onerous contract was calculated using present value of the future commitment payments, based on the volume shortfall, discounted using a risk adjusted rate of 12% .

Note 14 – Decommissioning Liabilities

The total future decommissioning liabilities were estimated by management based on the Company's net ownership interest in all wells, gathering lines and facilities, estimated costs to reclaim and abandon the wells and facilities and the estimated timing of the costs to be incurred.

Changes to decommissioning liabilities were as follows:

	June 30, 2016	December 31, 2015
Balance, beginning of period	$ 220,306	$ 198,387
Change in estimate	25,528	17,130
Obligations incurred	78	1,855
Obligations acquired	—	—
Obligations disposed	(407)	(68)
Obligations settled	(395)	(2,077)
Accretion	2,240	5,079
Balance, end of period	$ 247,350	$ 220,306

The decommissioning liabilities have been calculated using an inflation rate of 2.0% and discounted using a risk free rate of 1.75% per annum (December 31, 2015 – inflation rate of 2.0% and risk free rate of 2.25%). Most of these obligations are not expected to be paid for several years extending up to 45 years in the future and are expected to be funded from the general resources of the Company at the settlement date. The change in estimate relates entirely to changes in the risk free rate.

(Unaudited, all tabular amounts are expressed in thousands of Canadian dollars unless otherwise noted)

Note 15 – Shareholders' Capital

Authorized

The authorized share capital of Lightstream consists of an unlimited number of common shares without nominal or par value.

Shareholders' Capital

	June 30, 2016		December 31, 2015	
Share Continuity (thousands of shares)	Number	Amount	Number	Amount
Balance, beginning of period	198,322	$ 2,368,272	197,304	$ 2,358,361
Exercise of stock options, incentive shares and deferred common shares	323	16	1,018	51
Share-based settlement on exercises	—	3,025	—	9,860
Balance, end of period	198,645	$ 2,371,313	198,322	$ 2,368,272

Contributed Surplus

Changes in Contributed Surplus	Amount
Balance at January 1, 2015	$ 164,619
Share-based compensation	6,146
Share-based settlement	(9,860)
Balance at December 31, 2015	$ 160,905
Share-based compensation	1,912
Share-based settlement on exercises	(3,025)
Balance at June 30, 2016	$ 159,792

Stock Options, Incentive Shares, Deferred Common Shares

The Company estimates the fair value of granted stock options, incentive shares and deferred common shares using a Black-Scholes pricing model.

Stock Options

Options granted under the stock option plan have an exercise price that is no less than the five day weighted average trading price of the Company's common shares on the TSX prior to the date of the grant. Stock option terms are determined by the Company's Board of Directors, but typically options vest over a period of one to four years from the date of grant and expire between five and ten years from the date of the grant.

(Unaudited, all tabular amounts are expressed in thousands of Canadian dollars unless otherwise noted)

The following is a continuity of stock options outstanding:

	June 30, 2016			December 31, 2015		
(thousands of options)	Stock Options		Weighted-Average Exercise Price	Stock Options		Weighted-Average Exercise Price
Balance, beginning of period	797	$	10.27	1,161	$	10.27
Expired	(4)		15.16	(53)		11.48
Forfeited	(177)		10.68	(311)		10.06
Balance, end of period	616	$	10.12	797	$	10.27
Exercisable	456	$	10.33	494	$	10.46

The following table summarizes information relating to the stock options outstanding at June 30, 2016:

Stock Options Outstanding

Range of exercise prices	Number (thousands of options)	Weighted - Average Remaining Contractual Life (Years)		Weighted-Average Exercise Price
$3.94 - $8.15	210	1.4	$	7.54
$8.16 - $11.58	244	1.2		10.49
$11.59 - $14.03	162	0.6		12.91
	616	1.1	$	10.12

Incentive Shares

Incentive shares have an exercise price of $0.05 per share with terms that are determined by the Company's Board of Directors. Typically the shares vest over a period of one to four years from the date of grant and expire between five and ten years from the date of the grant.

The following is a continuity of incentive shares outstanding:

(thousands of shares)	June 30, 2016	December 31, 2015
Balance, beginning of period	8,650	4,225
Granted	15	6,156
Exercised	(284)	(913)
Forfeited	(441)	(784)
Expired	(8)	(34)
Balance, end of period	7,932	8,650
Exercisable (1)	1,215	1,366

(1) Incentive shares vested and exercisable into common shares at $0.05 per share.

Deferred Common Shares

Deferred common shares have an exercise price of $0.05 per share with terms that are determined by the Company's Board of Directors. Typically the shares vest over a period of one to four years from the date of grant and expire between five and ten years from the date of the grant.

(Unaudited, all tabular amounts are expressed in thousands of Canadian dollars unless otherwise noted)

The following is a continuity of deferred common shares outstanding:

(thousands of shares)	June 30, 2016	December 31, 2015
Balance, beginning of period	560	665
Exercised	(38)	(105)
Balance, end of period	522	560
Exercisable [(1)]	308	172

(1) Deferred Common Shares vested and exercisable into common shares at $0.05 per share.

Note 16 – Earnings per Share

The following table summarizes the basic and diluted weighted average number of common shares used in calculating earnings per share:

	Three months ended June 30,		Six months ended June 30,	
	2016	2015	2016	2015
Weighted average common shares outstanding, basic and diluted [(1)]	198,581	197,470	198,501	197,406
Net income (loss) and comprehensive income (loss)	$ (709,469)	$ (51,533)	$ (691,056)	$ (178,274)
Basic earnings (loss) per share	$ (3.57)	$ (0.26)	$ (3.48)	$ (0.90)
Diluted earnings (loss) per share	$ (3.57)	$ (0.26)	$ (3.48)	$ (0.90)

(1) Thousands of shares.

In determining the weighted average number of common shares outstanding on a diluted basis for the three months and six months ended June 30, 2016, 0.6 million stock options, 7.9 million incentive shares and 0.5 million deferred common shares were excluded because the effect would be anti-dilutive (2015 - 4.2 million incentive shares and 0.6 million deferred common shares).

Note 17 – Capital Management

The Company's capital structure includes common shares, credit facility outstanding, secured notes, senior unsecured notes and working capital deficit. The Company's policy has been to provide flexibility for the future development of the business. In order to maintain or adjust the capital structure, from time to time and subject to applicable restrictions in its debt agreements, the Company may issue/repurchase common shares, issue/ repurchase debt or other securities, sell assets or adjust capital spending or dividend payments to manage current and projected debt levels. The Company assesses its capital structure and makes adjustments to it in light of changes in economic conditions and the risk characteristics of the underlying assets.

(Unaudited, all tabular amounts are expressed in thousands of Canadian dollars unless otherwise noted)

As at,	June 30, 2016	December 31, 2015
Working capital deficit[1]	$ 40,079	$ 26,619
Secured termed credit facility – principal	359,000	344,188
Secured notes - principal amount (US$)	650,000	650,000
Convertible debentures – principal amount (US$)	—	4,500
Senior unsecured notes – principal amount (US$)	253,946	253,946
Shareholders' capital	2,371,313	2,368,272
Secured termed credit facility – lending limit	$ 250,000	$ 550,000
Available credit capacity [2]	$ —	$ 194,739

(1) Working capital deficit is calculated as accounts payable and accrued liabilities less cash and cash equivalents, accounts receivable and prepaid expenses.
(2) Available credit capacity reduced by $11.9 million (December 31, 2015 - $11.1 million) to reflect issued letters of credit. At June 30, 2016, the Company had no available capacity as the lending limit was reduced to an amount lower than the net draw on the Credit Facility.

On April 29, 2016, the Company's Credit Facility was reduced from $550 million to $250 million (Note 9). As at June 30, 2016, the Company had $371 million drawn on the Credit Facility. In light of this change and the resulting lack of liquidity, the Company is pursuing the Recapitalization aimed at reducing the Company's overall debt. Refer to Note 1 for details.

The following table shows the effect of the CBCA Plan on the Company's capital structure as at June 30, 2016:

As at,	June 30, 2016	Pro Forma June 30, 2016
Total long-term debt [1]	$ 1,529,975	$ 359,000
Shareholder's equity	(232,475)	977,137
Total Capitalization	$ 1,297,500	$ 1,336,137
Long-term debt to equity	Not measurable	37%
Long-term debt as a percentage of capitalization	118 %	27%

(1) Long-term debt is stated at its carrying amount and consists of current and long-term secured termed credit facility, secured notes and senior unsecured notes.

A completed Recapitalization would result in the Company significantly reducing long-term debt and restructuring its overall capitalization.

The Company uses a ratio of debt to trailing twelve month Adjusted EBITDA and the amount of available credit facility capacity to monitor leverage and the strength of the balance sheet. In order to facilitate the management of these measures, the Company prepares budgets, which are updated as necessary depending on varying factors, including current and forecast commodity prices, changes in capital structure, execution of the Company's business plan and general industry conditions. The budget is approved by the Lightstream Board of Directors and updates are prepared and reviewed as required.

At June 30, 2016, the Company was in compliance with the financial covenant on the Credit Facility. The Credit Facility had one financial covenant that limited the ratio of first lien debt (meaning total amounts outstanding under the Credit Facility) to Adjusted EBITDA on a trailing twelve month basis to 3.75:1, and at June 30, 2016 that ratio was 1.82:1.

The Company has certain restrictive financial covenants on the Secured Notes and Unsecured Notes which limit the Company's ability to incur additional debt, pay dividends, and repurchase stock, among other restrictions. In anticipation of triggering events of default under the Company's Secured Notes indenture and the Unsecured Notes indenture, and in connection with the Recapitalization, the Company received a preliminary interim order from the Court of Queen's Bench of Alberta containing a stay prohibiting any person, including the Secured Noteholders and the Unsecured Noteholders from terminating, making any demand, accelerating, amending or declaring in default or taking any enforcement steps under any contract or other agreement to which the Company is a party.

(Unaudited, all tabular amounts are expressed in thousands of Canadian dollars unless otherwise noted)

Note 18 – Financial Instruments and Financial Risk Management

The Company uses derivative instruments to reduce its exposure to fluctuations in commodity prices and foreign exchange rates.

Foreign Exchange Contracts

Lightstream, from time to time, enters into short-term foreign exchange contracts for its U.S. denominated interest payments and other routine transactions. There were no foreign exchange contracts in place as at June 30, 2016.

Commodity Contracts

The Company uses derivative instruments to reduce its exposure to fluctuations in commodity prices. The following is a summary of crude oil derivative contracts in place as at June 30, 2016:

Crude Oil Price Risk Management Contracts – WTI

Remaining Term	Volume (bopd)	Average Price ($/bbl)(1)	Type
Jul. 2016 - Dec. 2016	1,250	US$49.40	Fixed Price Swap

(1) Prices are the volume weighted average prices for the period.

The following is a summary of crude oil differential derivative contracts in place as at June 30, 2016:

Crude Oil Differential Derivative Contracts – Edmonton SW

Remaining Term	Volume (bopd)	Average Differential ($/bbl)(1)	Type
Jul. 2016 - Dec. 2016	3,000	US$3.78	Fixed Price Swap

(1) Prices are the volume weighted average prices for the period.

The following is a summary of natural gas derivative contracts in place as at June 30, 2016:

Remaining Term	Volume (GJ/d)	Average Price ($/GJ)(1)	Type
Jul. 2016 - Dec. 2016	5,000	$2.91	Fixed Price Swap

(1) Prices are the volume weighted average prices for the period.

The following is a summary of the fair value of risk management contracts in place at June 30, 2016 and December 31, 2015:

As at,	June 30, 2016			December 31, 2015		
	Asset	Liability	Net	Asset	Liability	Net
Crude oil	$ 73	$ (452)	$ (379)	$ 8,666	$ —	$ 8,666
Natural gas	444	—	444	859	—	859
Foreign exchange	—	—	—	207	—	207
Total	$ 517	$ (452)	$ 65	$ 9,732	$ —	$ 9,732

(Unaudited, all tabular amounts are expressed in thousands of Canadian dollars unless otherwise noted)

Fair Value of Financial Derivative Contracts

The unrealized gain/loss represents the fair value of the underlying risk management contracts to be settled in the future. The realized gain/loss represents the risk management contracts settled during the period.

The table below summarizes the components of gain (loss) on risk management contracts:

	Three months ended June 30,		Six months ended June 30,	
	2016	2015	2016	2015
Realized gain (loss) on risk management contracts:				
Crude oil derivative contracts	$ 1,421	$ 19,457	$ 6,787	$ 47,810
Natural gas derivative contracts	625	12	1,137	12
Foreign exchange contracts	(752)	(2)	(366)	1,487
	1,294	19,467	7,558	49,309
Unrealized gain (loss) on risk management contracts:				
Crude oil derivative contracts	(5,257)	(37,074)	(9,045)	(45,576)
Natural gas derivative contracts	(1,258)	62	(415)	62
Foreign exchange contracts	514	262	(207)	295
	(6,001)	(36,750)	(9,667)	(45,219)
(Loss) gain on risk management contracts	$ (4,707)	$ (17,283)	$ (2,109)	$ 4,090

Fair value of Financial Instruments

The Company's financial instruments include cash and cash equivalents, accounts receivable, long-term investments, accounts payable and accrued liabilities, risk management assets and liabilities, secured termed credit facility, secured notes, convertible debentures, and senior unsecured notes on the consolidated balance sheet.

The Company classifies the fair value of these financial instruments according to the following hierarchy based on the amount of observable inputs used to value the instrument:

Level 1 - Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. Active markets are those in which transactions occur in sufficient frequency and volume to provide pricing information on an ongoing basis.

Level 2 - Pricing inputs are other than quoted prices in active markets included in Level 1. Prices in Level 2 are either directly or indirectly observable as of the reporting date. Level 2 valuations are based on inputs, including quoted forward prices for commodities, time value and volatility factors, which can be substantially observed or corroborated in the marketplace.

Level 3 - Valuations in this level are those with inputs for the asset or liability that are not based on observable market data.

Assessment of the significance of a particular input to the fair value measurement requires judgment, estimates, and assumptions and may affect the placement within the fair value hierarchy level. Actual results may differ from these estimates.

(Unaudited, all tabular amounts are expressed in thousands of Canadian dollars unless otherwise noted)

Due to the short-term nature of accounts receivable, accounts payable and accrued liabilities, their carrying value approximates their fair value. The credit facility bears interest at a floating rate and accordingly the fair value approximates the carrying value excluding deferred financing costs.

The carrying value and fair value of these financial instruments at June 30, 2016 is disclosed below by financial instrument classification:

	June 30, 2016		December 31, 2015	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Financial Assets				
Cash and cash equivalents	$ 31,235	$ 31,235	$ —	$ —
Accounts receivable	39,451	39,451	53,858	53,858
Long-term investments [(1)]	446	446	344	344
Risk management asset[(2)]	517	517	9,732	9,732
Financial Liabilities				
Accounts payable and accrued liabilities	116,976	116,976	86,040	86,040
Secured termed credit facility	355,429	359,000	340,832	344,188
Secured notes [(2)]	845,585	467,186	899,600	562,250
Convertible debentures[(2)]	—	—	6,164	4,982
Senior unsecured notes[(2)]	325,390	23,539	345,565	91,383
Risk management liabilities[(2)]	$ 452	$ 452	$ —	$ —

(1) Level 1
(2) Level 2

Note 19 – Changes in Non-Cash Working Capital

	Three months ended June 30,		Six months ended June 30,	
	2016	2015	2016	2015
Change in:				
Accounts receivable	$ (3,435)	$ 6,467	$ 14,407	$ 22,960
Prepaid expenses	(3,557)	(1,718)	(648)	(1,289)
Accounts payable and accrued liabilities	29,308	(39,421)	30,936	(122,582)
Other	(307)	(562)	(614)	(1,055)
	$ 22,009	$ (35,234)	$ 44,081	$ (101,966)
Changes relating to:				
Attributable to operating activities	$ 22,849	$ 5,280	$ 46,599	$ (7,448)
Attributable to investing activities	$ (820)	$ (40,461)	$ (2,471)	$ (90,851)
Attributable to financing activities	$ (20)	$ (53)	$ (47)	$ (3,667)

(Unaudited, all tabular amounts are expressed in thousands of Canadian dollars unless otherwise noted)

Note 20 – Commitments and Contingencies

The following is a summary of the estimated costs required to fulfill the Company's remaining contractual commitments at June 30, 2016:

Type of commitment	1 Year	2-3 Years	4-5 Years	Thereafter	Total
Office leases [1]	$ 3,800	$ 11,489	$ 3,863	$ —	$ **19,152**
Marketing commitments	6,055	9,913	850	3,238	**20,056**
Total [2]	$ **9,855**	$ **21,402**	$ **4,713**	$ **3,238**	$ **39,208**

(1) Includes sublease recoveries of $0.2 million (1 Year).
(2) Commitments do not include onerous contracts reflected in Note 13.

Note 21 - Subsequent Events

On July 12, 2016, the Company announced the Recapitalization plan aimed at reducing the Company's debt and annual interest and providing additional liquidity to fund ongoing operations. Refer to Note 1.

On August 2, 2016, the Company elected not to make the interest payment on the Unsecured Notes. Refer to Note 12 for details.

CORPORATE INFORMATION

DIRECTORS

Ian Brown [1][4]
Calgary, Alberta

Martin Hislop [1][3]
Calgary, Alberta

Kenneth McKinnon [1][3][4][5]
Calgary, Alberta

Corey C. Ruttan [1][2][4]
Calgary, Alberta

W. Brett Wilson [2][3]
Calgary, Alberta

John D. Wright [2]
Calgary, Alberta

(1) Member of the Audit Committee
(2) Member of the Reserves Committee
(3) Member of the Compensation Committee
(4) Member of the Governance and Nominating Committee
(5) Chairman of the Board of Directors

REGISTRAR AND TRANSFER AGENT

Computershare
600, 530 – 8th Avenue SW
Calgary, Alberta T2P 3S8
TEL: 1 (800) 564-6253
FAX: 1 (888) 453-0330

LEGAL COUNSEL

McCarthy Tétrault LLP
Calgary, Alberta, Canada

BANKERS

The Toronto-Dominion Bank
Calgary, Alberta, Canada

AUDITORS

Deloitte LLP
Calgary, Alberta, Canada

RESERVE ENGINEERS

Sproule Associates Limited
Calgary, Alberta, Canada

EXCHANGE LISTING

The Toronto Stock Exchange
SYMBOL: LTS

OFFICERS

Annie Belecki
General Counsel

Mary Bulmer
Vice President, Corporate Services

Lawrence Fisher
Vice President, Land

Peter Hawkes
Vice President, Geosciences

Rene LaPrade
Senior Vice President and
Chief Operating Officer

Brad Malley
Vice President, Development Services

Doreen Scheidt
Vice President and Controller

Peter D. Scott
Senior Vice President and Chief Financial Officer

John D. Wright
President and Chief Executive Officer

HEAD OFFICE

Lightstream Resources Ltd.
Eighth Avenue Place
2800, 525 – 8th Avenue SW
Calgary, Alberta T2P 1G1

TEL: (403) 268-7800
FAX: (403) 218-6075
WEBSITE: http://www.lightstreamresources.com
EMAIL: ir@lightstreamres.com

SECURITIES FILINGS

www.sedar.com

Information requests and other investor relations inquiries can be directed to ir@lightstreamres.com or by telephone at (403) 268-7800. Additional corporate information can be obtained through Lightstream's website at http://www.lightstreamresources.com

CAUTIONARY STATEMENTS

Capitalized terms used but not otherwise defined herein have the meanings ascribed to such terms in our press release dated July 12, 2016.

As part of our negotiations with the Ad Hoc Committee, and pursuant to confidentiality agreements, Lightstream Resources (the "Company" or "Lightstream") provided Secured Noteholders who were parties to such agreements, with certain internal financial projections regarding the Company, including internal production forecasts, budgeting scenarios and reserves sensitivity analyses (the "Restructuring Information"). This Restructuring Information was prepared by management of the Company as at May 31, 2016, represents a small sample of a number of possible scenarios and is subject to interpretation as well as a number of significant assumptions. As a result, readers are cautioned that the Restructuring Information does not necessarily reflect the Company's current circumstances or the current estimates or projections of management. Neither the board of directors of the Company nor any of its committees approved the projections or analyses contained in the Restructuring Information.

The Company does not, as a matter of course, publish reserves sensitivity analyses or our budgets or publish internal projections or forecasts of our anticipated financial position, expenditures, cash balances or cash flows. The Restructuring Information was prepared for the purposes of negotiating the transactions contemplated in the Support Agreement and was not prepared with a view to being disclosed publicly. It has been posted to the Company's website only because such information was made available to certain members of the Ad Hoc Committee and is not appropriate for any other purpose. Therefore, the Restructuring Information should not be regarded as an indication that Lightstream or any other person considered, or now considers, this information to be necessarily predictive of actual future results, and does not constitute an admission or representation by any person that such information is material, or that the expectations, beliefs, opinions, and assumptions that underlie such information remain the same as of the date of this presentation. Given the highly speculative nature of the information provided and the assumptions underlying it, as well as the fact that the information represents only one of a number of possible scenarios, Lightstream does not view the Restructuring Information provided to the members of the Ad Hoc Committee and as subsequently posted to the Lightstream website as material. The Restructuring Information may be incomplete, may no longer be accurate, is subject to interpretation and should not be relied upon by any person in making an investment decision or for any other purpose.

In all cases, the Restructuring Information is also subject to significant risks, including the risk factors set forth in the Company's annual information form for the year-ended December 31, 2015 which is filed under the Company's profile on SEDAR at www.sedar.com (the "AIF") under the heading "Risk Factors" and under the headings "Risks and uncertainties" and "Sensitivities" in the Company's management's discussion and analysis for the year-ended December 31, 2015 and for the three-months ended March 31, 2016 (together, the "MD&A") which are also filed on SEDAR.

In addition to the foregoing, the financial information provided in the Restructuring Information was not prepared in accordance with International Financial Reporting Standards ("IFRS") and is therefore unlikely to be comparable to similar information presented by other issuers. Neither the independent auditor of the Company nor any other independent accountant has examined the Restructuring Information nor expressed any opinion or other form of assurance on such Restructuring Information. For financial information respecting the Company, reference should be made to the Company's annual audited financial statements for the year-ended December 31, 2015 and accompanying management's discussion and analysis and its interim financial statements for the three-months ended March 31, 2016 and accompanying management's discussion and analysis, as filed on SEDAR. Further, as the Restructuring Information was not prepared with a view to being disclosed publicly, the internal production forecasts and reserves sensitivity analyses provided in the Restructuring Information was not prepared in accordance with National Instrument 51-101 – *Standards of Disclosure for Oil and Gas Activities* or the related staff notices of the Canadian Securities Administrators and therefore should not be relied upon by investors. Information respecting the Company's reserves and resources is available in the Company's AIF under the headings "Statement of Reserves Data" and "Additional Information Relating to Reserves Data".

Subject to applicable securities laws, the Company does not intend to or anticipate that we will, and we further disclaim any obligation to furnish updated projections, sensitivity analyses or forecasts or similar forward looking information to holders of securities issued by the Company or to include such information in documents required to be filed with the applicable Canadian Securities Administrators or otherwise make such information publicly available.

LIGHTSTREAM RESOURCES

EXHIBIT 4 **DATE** Oct 3/16

WITNESS P. D. Scott

HEATHER BOWIE
COURT REPORTER

CAUTIONARY STATEMENTS (CONTINUED)

Forward Looking Statements. Certain information provided in this presentation constitutes forward-looking statements. Specifically, this presentation contains forward-looking statements relating to financial projections, including internal production forecasts, budgeting scenarios and reserves sensitivity analyses based on certain assumptions including oil and gas prices, production levels, operating and general and administrative expenses and capital expenditures and timing of development. Readers are cautioned that the scenarios do not reflect the Company's current circumstances or the current estimates or projections of management.

Non-GAAP measures. This presentation contains a number of financial terms that are not considered measures under IFRS. These measures do not have any standardized meaning prescribed by IFRS and therefore may not be comparable to those reported by other companies. These measures are considered informative for management and stakeholders as they help evaluate performance and demonstrate the ability to generate sufficient cash to fund future growth opportunities, pay dividends and repay debt. These measures should not be viewed as an alternative to cash flow from operations, net income or other measures of financial performance calculated in accordance with IFRS. Further information and reconciliations to the most directly comparable IFRS financial measures in respect of these non-GAAP measures is set forth in our MD&A.

Reserves information. Unless indicated otherwise, reserve estimates and other reserves information is derived from Lightstream's independent reserve report prepared by Sproule Associates Limited as at December 31, 2015 using forecast prices and costs.

Boe presentation. Natural gas volumes have been converted to barrels of oil equivalent ("boe"). Six thousand cubic feet ("Mcf") of natural gas is equal to one barrel of oil equivalent based on an energy equivalency conversion method primarily attributable at the burner tip and does not represent a value equivalency at the wellhead. Boes may be misleading, especially if used in isolation.

LIGHTSTREAM RESOURCES

LIGHTSTREAM RESOURCES

Management Presentation

May 31, 2016

EVERCORE

EVERCORE

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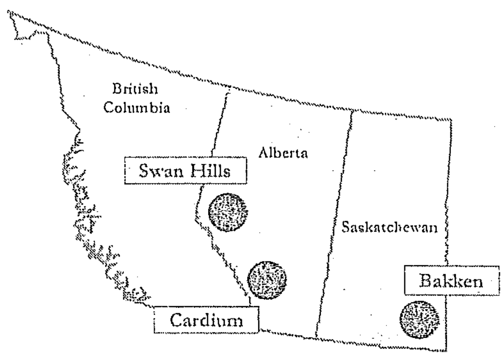
I. Executive Summary

EVERCORE

Company and Asset Overview

- Lightstream Resources Ltd (TSX: LTS) is a light oil-focused exploration and production company with an extensive portfolio of resource plays
- Over 2,000 net wells on production in three light-oil plays (~75% liquids weighted):
  - Southeastern Saskatchewan – targeting Bakken formation
  - Central Alberta – targeting the Cardium formation
  - North-central Alberta – are in the early stages of developing the Swan Hills formation

Asset Location



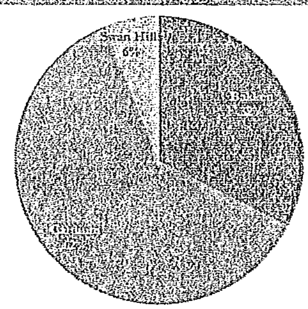
Drilling Locations

- Currently over 1,500 drilling locations; company prepared to execute drilling program once macro economic conditions support investment

Drilling Locations	
Bakken	>1,000
Cardium	>400
Swan Hills	>100
Total	>1,500

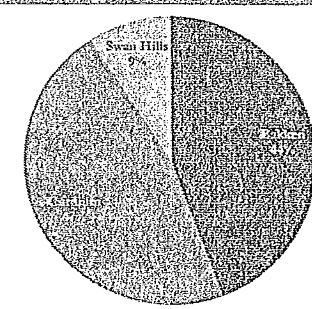
Asset Concentration

Net Acreage



Total Net Acres: 936,000

Proved Reserves



Total Proved Reserves: 126 MBoe

Source: May 2016 investor presentation, LTS 2015 YE annual information form

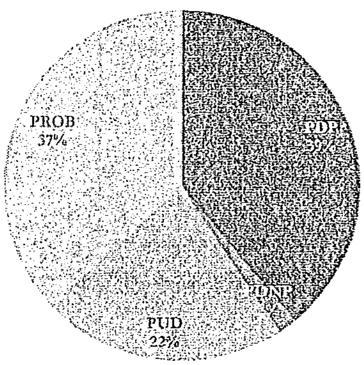
Executive Summary

Reserves Data

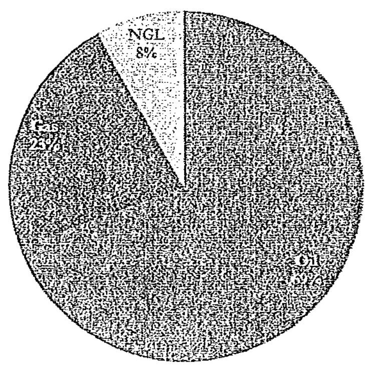
Net Reserves Table[1]

	Oil (MMBbls)	Gas (Bcf)	NGL (MMBbls)	Total (MMBoe)	% Liquids	PV10 (C$MM)
PDP	32.2	77.1	4.2	49.2	74%	$1,036
PDNP	1.3	3.7	0.2	2.1	71%	33
PUD	20.4	33.3	2.2	28.1	80%	215
Total Proved	53.9	114.1	6.5	79.4	76%	$1,284
PROB	33.6	56.3	3.7	46.7	80%	573
Total 2P	87.5	170.4	10.2	126.1	77%	$1,857

Reserve Category Mix



Commodity Mix



Source: LTS 2015 YE annual information form
(1) Economics run on Sproule December 31, 2015 price deck (2016, 2017, 2018 price of US$45,60,70/bbl WTI)

Executive Summary

(CAD$ in millions)

- The bank group under Lightstream's secured credit facility ("RBL") finalized its semi-annual redetermination on May 2, 2016
  - Reduced Borrowing Base from $550 million to $250 million
    - Set by the lowest determined amount; the Borrowing Base range was from $250 million to $380 million
    - The Company has $371 million of exposure under the RBL ($359 million drawn plus $12 million of LCs) and $24 million of cash as of May 31, 2016
  - Company must cure deficiency by July 28, 2016

- Company is pursuing strategic alternatives with goal to be completed or well in progress prior to June 30, 2016:
  - Alternate 1st Lien financing
  - Asset sales
  - Restructuring alternatives

- The Company has developed a 3-year Base Case Business Plan at strip pricing and flat production (~25,000 boepd exit) as well as an Upside Case which reflects a price recovery and incremental drilling (~30,000 boepd exit) and a Downside Case reflecting US$40/bbl WTI pricing and a limited drilling program (~20,000 boepd exit)
  - The Base Case and the Upside Case result in ~$200 million and ~$350 million of EBITDA in 2018, respectively
  - Notably, neither the Base Case nor the Upside Case require an investment of "new money" into the Company beyond a new cash flow revolver to refinance the existing RBL and the Downside Case requires minimal new money investment through 2018
  - The Base Case, Upside Case and Downside Case assume equitization of the existing 2nd Lien and Unsecured Notes

- The Company and its advisors aim to achieve a fully-consensual restructuring transaction with support of all of the Company's funded debt holders
  - Targeting announcement of transaction by June 30, 2016

II. Business Plans

EVERCORE

Business Plans

Introduction

- The Company has developed a 3-year Base Case Business Plan (2016-2018)
- The proposed 3 year program is focused on exploiting the highest return assets, maintaining production and preserving land
  - Results in flat production of ~25,000 boed
  - Features most economic wells in the portfolio and "low-hanging fruit" projects
  - Allows the Company to hold all desired acreage
  - Adds three rigs in Bakken starting 2H 2016 with two rigs in 2017 & 2018
  - Modest West Pembina program targeting the highest quality locations
- Free cash flow (after capital expenditures) provides flexibility to accelerate drilling, reduce debt, acquire assets, etc.
  - $40-60 million each year at current strip prices (as of May 25, 2016)
  - The Base Case is self-funding – does not require a new money investment

Key Assumptions – Base Case

<table>
<tr><td>Pricing</td><td>

- NYMEX (WTI) and NGX (AECO) monthly strip pricing through YE 2016 and yearly averages thereafter

Forecast Commodity Prices[1]	2016 Average	2017 Average	2018 Average
Oil - WTI (US$/Bbl)	$44.79	$51.63	$52.35
AECO (C$/GJ)	$1.64	$2.56	$2.74

- Royalty rates consistent with lower strip pricing deck versus a recovery pricing deck and averages 10.1%, 8.9%, 7.9% in 2016, 2017 and 2018, respectively

</td></tr>
<tr><td>Production</td><td>

- Production relatively flat at 25.5 MBoed in 2016 (68% liquids) and 24.9 MBoed in 2018 (70% liquids)

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<tr><td>LOE (2)</td><td>

- $13.43/Boe in 2016 rising to $14.56/Boe in 2018
  - $12.32/Boe in 1Q2016

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<tr><td>G&A Expenses</td><td>

- $31.9 million in 2016 with total compensation kept relatively flat at $31.9 million in 2017 and 2018
- $3.42/Boe in 2016 rising to $3.51/Boe in 2018

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<tr><td>Capex / Development</td><td>

- The proposed 3 year program is focused on exploiting the highest return assets, maintaining production and preserving land
- Features most economic wells in the portfolio and "low-hanging fruit" projects
- Allows the Company to hold all desired acreage
- Adds three rigs in Bakken starting 2H 2016 with two rigs in 2017 & 2018
- Modest West Pembina program targeting the highest quality locations
- $85 million capital budget in 2016 (69% D&C), $153 million in 2017 (82% D&C) and $123 million in 2018 (80% D&C)

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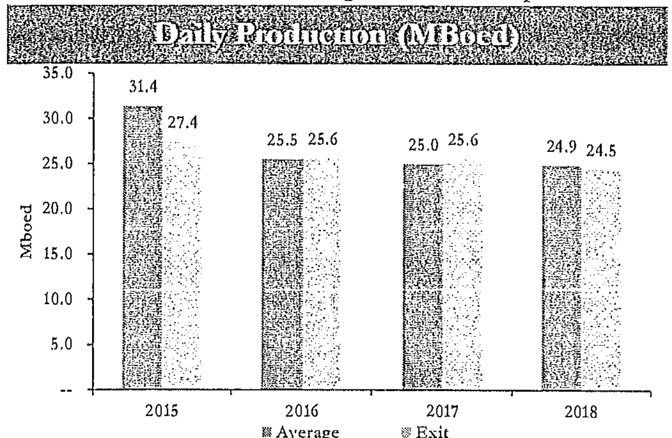
</table>

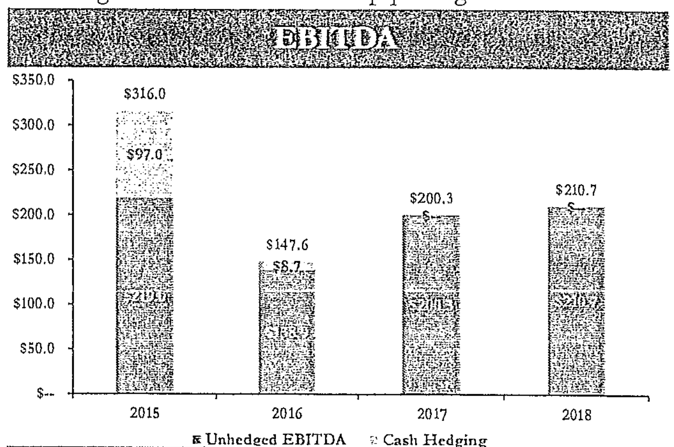
(1) Strip pricing as of May 25, 2016
(2) Includes transportation costs

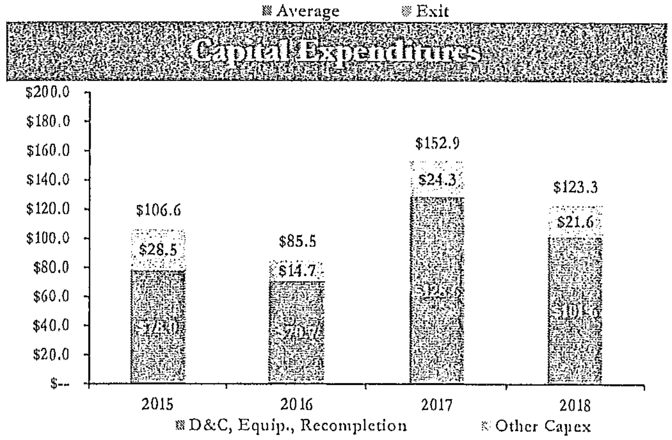
Financial Projections: Base Case (Flat Production @ Strip)

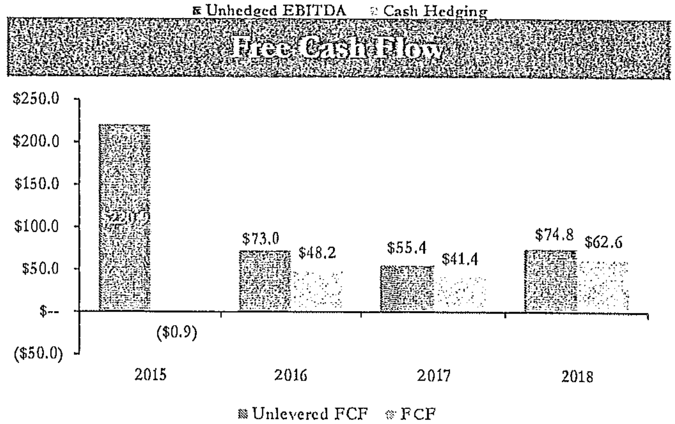
(CAD $ in millions)

- The Base Case is self-funding, maintains flat production and generates significant EBITDA at Strip pricing









(1) Note: WTI pricing in US$/Bbl

Business Plans

Sensitivities

- In addition, the Company has developed the following upside and downside sensitivities

	WTI Pricing (US$/bbl)[1]			Drilling Program					
	2016	2017	2018	Base Capital	2H16 3 Rig Bakken, 2 Rig Bakken in 2017 & 2018, + Limited 2017 Cardium	Inc. 2017 Bakken Rig	Inc. 2017 Cardium Rig	3 Inc. 2018 Bakken Rigs	3 Inc. 2018 Cardium Rigs
Base Case	$44.79	$51.63	$52.35	✓	✓				
Upside Case	$44.58	$55.00	$60.00	✓	✓	✓	✓	✓	✓
Downside Case	$38.89	$40.00	$40.00	✓					

- Base Capital Program: Focus on most economic wells in portfolio which reduces the risk of not reaching payout if commodity prices turn sharply lower and allows Company to hold all desired acreage
- Incremental opportunities to add:
  - 3 rigs in Bakken and high quality locations in West Pembina (2H16 3 Rig Bakken + Cardium)
  - Additional rigs in 2017 (1 in Bakken and 1 in Cardium)
  - Up to 3 additional Bakken rigs in 2018
  - Up to 3 additional Cardium rigs in 2018

(1) Full year average weighted by net production

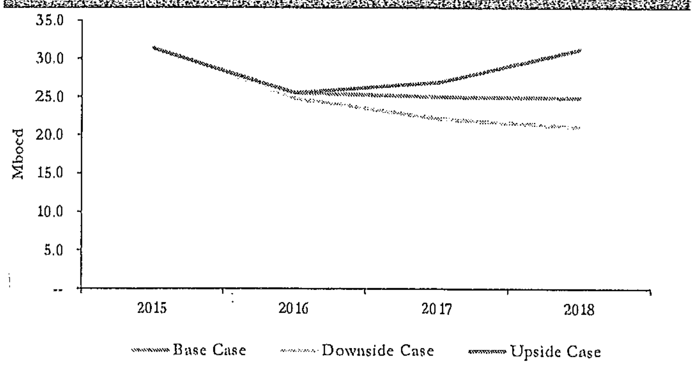
Business Plans

Financial Projections: Overview of Cases

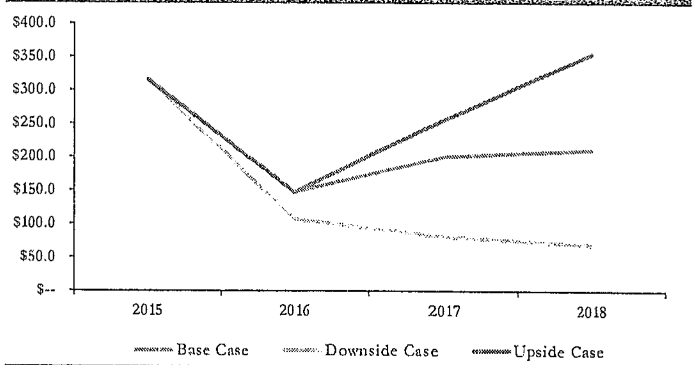
(CAD$ in millions)

- There is significant potential upside while downside is limited

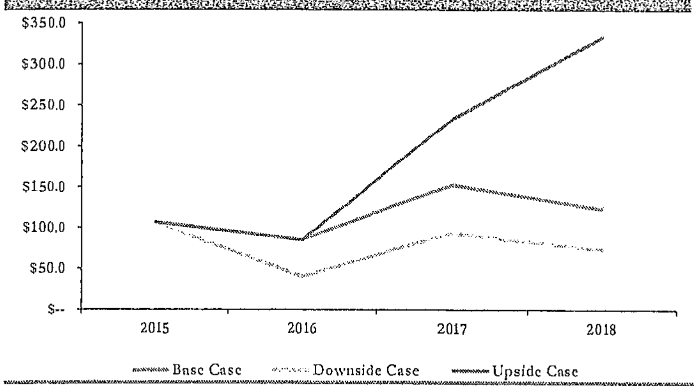
Daily Production (MBoed)



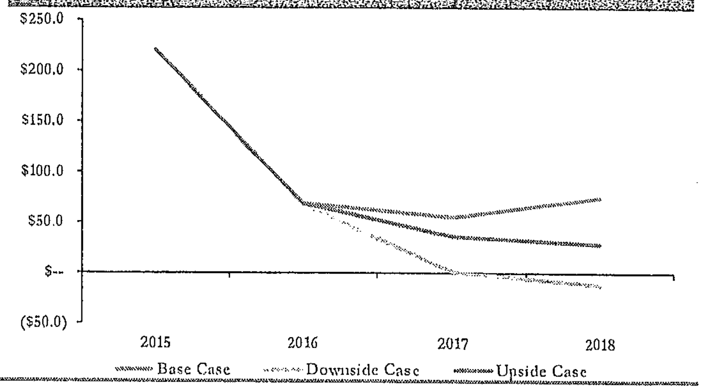
EBITDA



Capital Expenditures



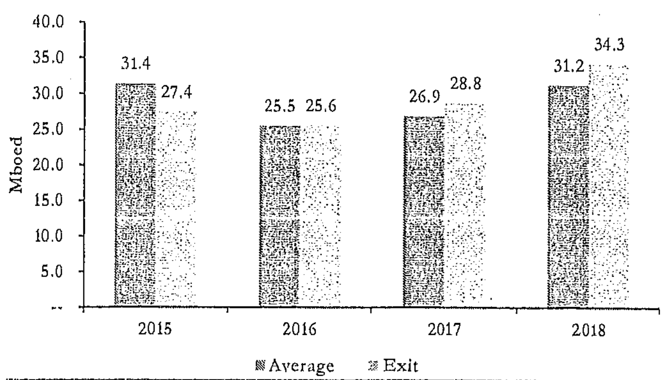
Unlevered Free Cash Flow



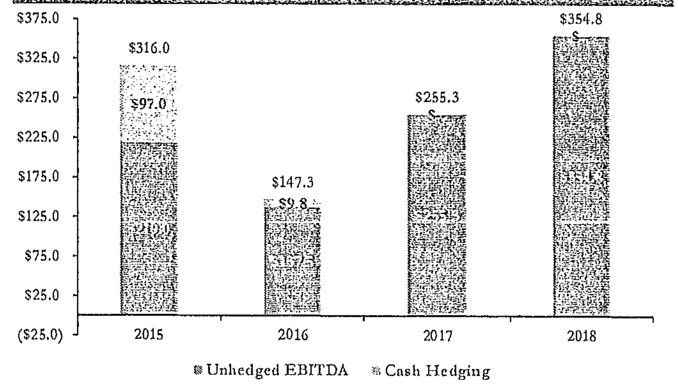
Financial Projections: Upside Case (High Production – Recovery Price) *(CAD$ in millions)*

- The Upside Case, which assumes a modest rebound to $60/bbl WTI in 2018, generates significant EBITDA and is self-funding

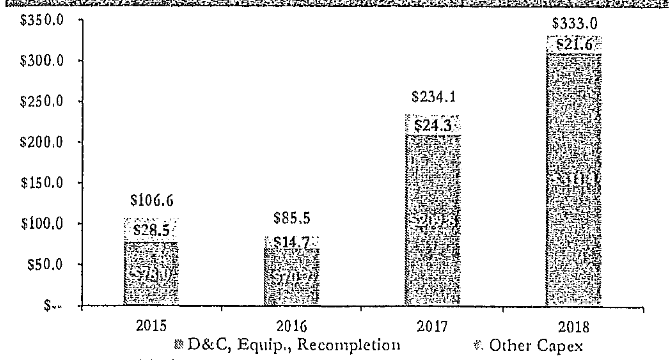
Daily Production (MBoed)



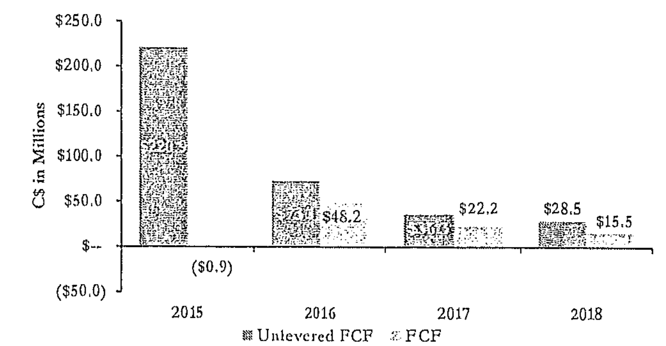
EBITDA



Capital Expenditures



Free Cash Flow

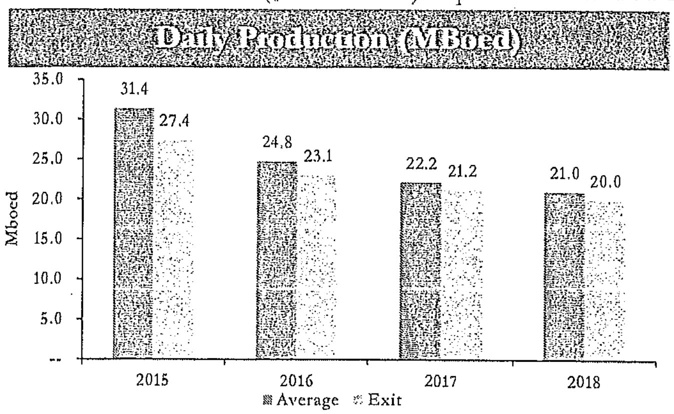


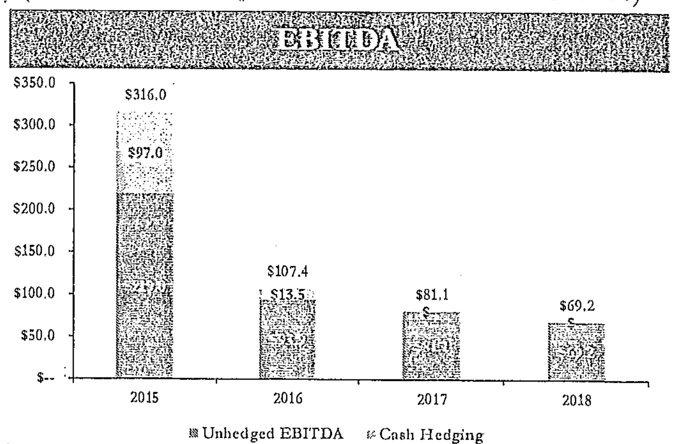
Note: WTI pricing in US$/Bbl

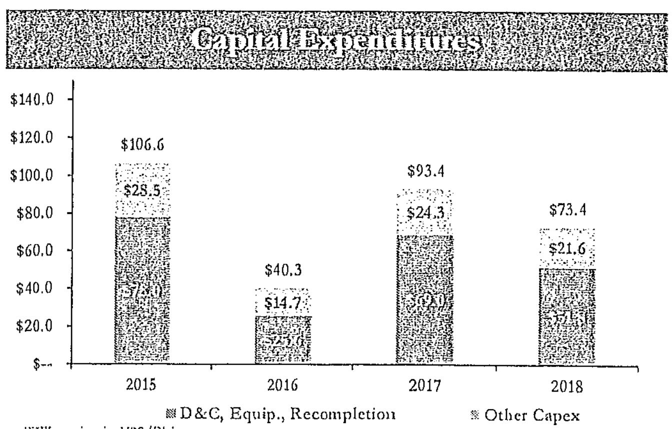
Financial Projections: Downside Case (Low Production – Flat Price)

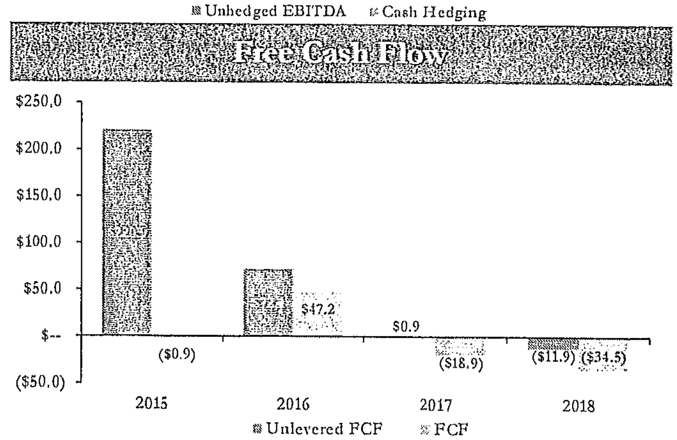
(CAD$ in millions)

- The Downside Case ($40 flat WTI) requires minimal new money (max drawdown of $375 million on RCF at end of 2018)









Note: WTI pricing in US$/Bbl

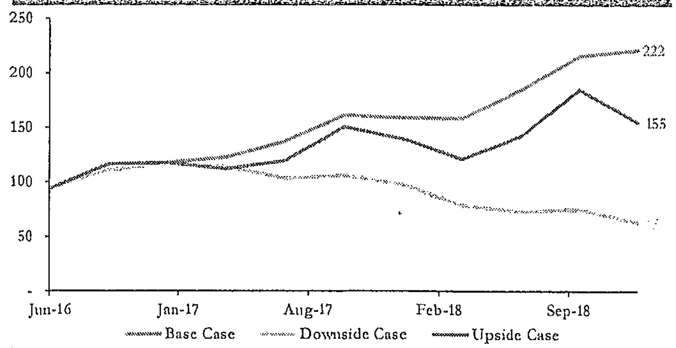
Business Plans

Liquidity, Leverage & Coverage Projections

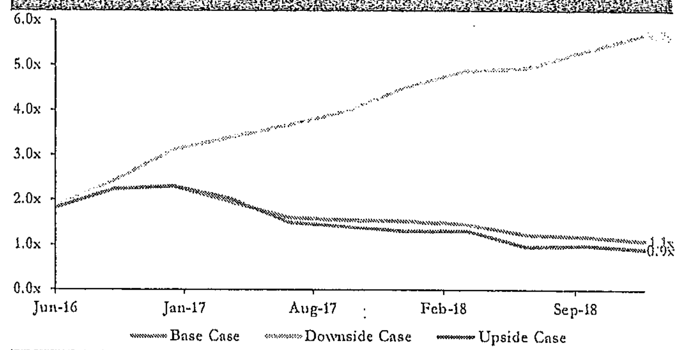
(CAD$ in millions)

- The Base and Upside Cases are highly deleveraging while the Downside Case results in leverage of ~6x in 2018

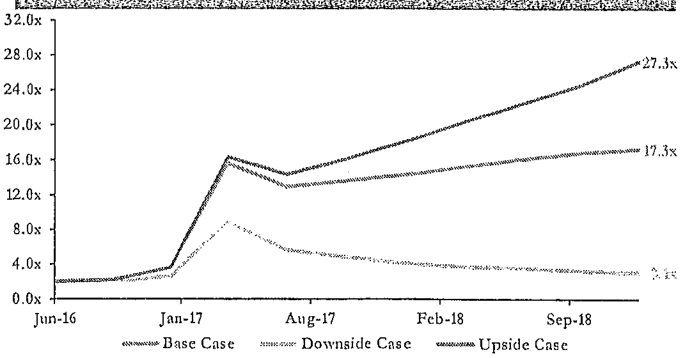
Liquidity(1)



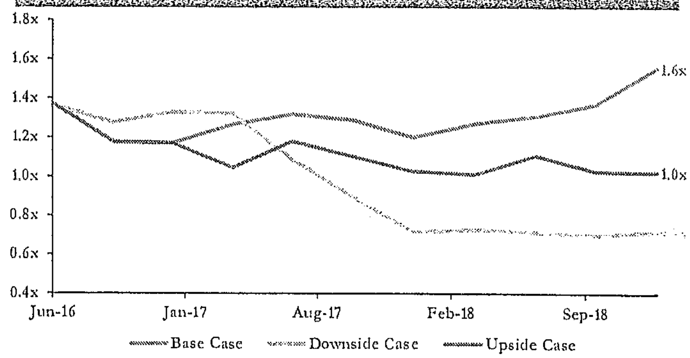
Total Net Leverage Ratio(2)



Interest Coverage Ratio(2)



Fixed Charge Coverage Ratio(2)(3)



(1) Post-transaction Revolver Commitment Size kept constant at CAD$450 million
(2) Financial ratios calculated on a trailing 12 month basis
(3) FCCR defined as trailing 12 month EBITDA divided by sum of trailing 12 month Cash Interest Expense and Capital Expenditure

III. Company Counterproposal [Section Redacted]

Pages 12 – 19 Redacted

Appendix

EVERCORE

Appendix

Pricing Scenarios

Strip Pricing as of 5/25/17

Commodity Prices	Q1 2016	Q2 2016	Q3 2016	Q4 2016	2016 Average[(1)]	2017 Average[(1)]	2018 Average[(1)]
Oil - WTI (US$/Bbl)	$33.46	$45.02	$49.92	$50.88	$44.79	$51.63	$52.35
NGL - Discount to WTI	70%	70%	70%	70%	70%	68%	60%
AECO (C$/GJ)	$1.72	$1.14	$1.56	$2.22	$1.64	$2.56	$2.74
WTI Diff (Excludes Well Head Diff)	($4.61)	($3.57)	($2.63)	($2.69)	($3.38)	($3.25)	($3.30)
FX Rate	0.7281	0.7701	0.7680	0.7683	0.7584	0.7688	0.7710

Recovery Pricing

Commodity Prices	Q1 2016	Q2 2016	Q3 2016	Q4 2016	2016 Average[(1)]	2017 Average[(1)]	2018 Average[(1)]
Oil - WTI (US$/Bbl)	$33.46	$45.02	$50.00	$50.00	$44.58	$55.00	$60.00
NGL - Discount to WTI	68%	70%	70%	70%	69%	68%	60%
AECO (C$/GJ)	$1.82	$1.23	$2.00	$3.00	$1.98	$3.00	$3.00
WTI Diff (Excludes Well Head Diff)	($4.61)	($4.48)	($5.00)	($4.50)	($4.65)	($4.95)	($4.50)
FX Rate	0.7281	0.7644	0.7500	0.7500	0.7480	0.7500	0.8000

Flat Pricing

Commodity Prices	Q1 2016	Q2 2016	Q3 2016	Q4 2016	2016 Average[(1)]	2017 Average[(1)]	2018 Average[(1)]
Oil - WTI (US$/Bbl)	$33.46	$42.54	$40.00	$40.00	$38.89	$40.00	$40.00
NGL - Discount to WTI	70%	65%	65%	65%	66%	65%	65%
AECO (C$/GJ)	$1.72	$1.39	$2.00	$2.00	$1.76	$2.00	$2.00
WTI Diff (Excludes Well Head Diff)	($4.61)	($4.04)	($4.00)	($4.00)	($4.17)	($4.00)	($4.00)
FX Rate	0.7281	0.7644	0.7500	0.7500	0.7479	0.7500	0.7500

(1) Weighted by net production

Appendix

Detailed Projections: Base Case

(CAD$ in millions)

	Quarterly Projections											Annual Projections		
	2016			2017				2018				2016	2017	2018
	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	FY	FY	FY
Oil - WTI (US$/Bbl)	$45.06	$49.91	$50.88	$51.63	$51.63	$51.63	$51.63	$52.35	$52.35	$52.35	$52.35	$44.83	$51.63	$52.35
NGL - Discount to WTI	70%	70%	70%	68%	68%	68%	68%	60%	60%	60%	60%	70%	68%	60%
AECO (C$/GJ)	$1.14	$1.56	$2.22	$2.56	$2.56	$2.56	$2.56	$2.74	$2.74	$2.74	$2.74	$1.66	$2.56	$2.74
Total Volumes (Boe/d)	25,517	24,699	25,492	25,755	24,917	24,092	25,265	26,077	25,462	23,622	24,381	25,518	25,007	24,885
Net Revenue	$71	$81	$91	$93	$90	$88	$94	$97	$95	$89	$93	$306	$364	$375
Total Expenses	39	41	38	43	40	40	41	43	41	40	40	158	164	164
EBITDA	$33	$40	$52	$50	$49	$47	$53	$54	$55	$49	$53	$148	$200	$211
Less: CapEx	(8)	(35)	(35)	(49)	(12)	(44)	(48)	(44)	(11)	(39)	(29)	(85)	(153)	(123)
Less: ΔNWC	(6)	21	(12)	7	(19)	25	(5)	(8)	(14)	24	(15)	(5)	8	(13)
Less: Cash Taxes	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Other	1	-	-	-	-	-	-	-	-	-	-	15	-	-
Unlevered Free Cash Flow	$20	$26	$5	$9	$18	$28	$1	$3	$29	$34	$9	$73	$55	$75
Less: Cash Interest	-	(4)	(4)	(4)	(4)	(3)	(3)	(3)	(3)	(3)	(3)	(25)	(14)	(12)
Levered Free Cash Flow	$20	$23	$1	$5	$15	$24	($3)	($0)	$26	$31	$6	$48	$41	$63
Plus: Credit Facility Draw	13	-	3	10	-	-	4	13	-	-	-	17	14	13
Less: Credit Facility Repayment	-	(23)	(4)	(15)	(15)	(24)	(1)	(12)	(26)	(31)	(6)	(27)	(55)	(75)
Less: Debt Repayment	(362)	-	-	-	-	-	-	-	-	-	-	(369)	-	-
Plus: Net Cash from Debt Issuance	345	-	-	-	-	-	-	-	-	-	-	345	-	-
Less: Transaction Costs & Fees	(15)	-	-	-	-	-	-	-	-	-	-	(15)	-	-
Change in Cash	$0	($0)	$0	$0	$0	$0	$0	$0	$0	($0)	($0)	($0)	$0	($0)
Beginning Cash Balance	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Plus: Change in Cash	-	(0)	0	0	0	-	0	-	-	(0)	(0)	(0)	0	(0)
Ending Cash Balance	$0	$0	$0	$0	$0	$0	$0	$0	$0	($0)	($0)	$0	$0	($0)
Plus: Revolver Availability	93	116	117	122	137	161	159	159	185	216	222	117	159	222
Total Liquidity	$93	$116	$117	$122	$137	$161	$159	$159	$185	$216	$222	$117	$159	$222
Ending Balances														
Revolving Credit Facility (CAD$450 million)	$345	$322	$321	$316	$301	$277	$279	$279	$253	$222	$216	$321	$279	$216
2nd Lien Notes	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Secured Debt	$345	$322	$321	$316	$301	$277	$279	$279	$253	$222	$216	$321	$279	$216
Senior Unsecured Notes	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Debt	$345	$322	$321	$316	$301	$277	$279	$279	$253	$222	$216	$321	$279	$216
Negative Working Capital	$9	$31	$18	$26	$7	$31	$26	$19	$5	$29	$14	$18	$26	$14
Total Debt incl. Negative Working Capital	$354	$352	$339	$341	$308	$308	$305	$298	$258	$251	$230	$339	$305	$230
Net Debt incl. Negative Working Capital	$354	$352	$339	$341	$308	$308	$305	$298	$258	$251	$230	$339	$305	$230
LTM EBITDA	$195	$158	$148	$175	$192	$199	$200	$204	$210	$211	$211	$148	$200	$211
Secured Net Leverage Ratio	1.8x	2.0x	2.2x	1.8x	1.6x	1.4x	1.4x	1.4x	1.2x	1.1x	1.0x	2.2x	1.4x	1.0x
Total Net Leverage Ratio	1.8x	2.2x	2.3x	2.0x	1.6x	1.5x	1.5x	1.5x	1.2x	1.2x	1.1x	2.3x	1.5x	1.1x

Note: Does not include the impact of cash received from exercise of Upside Tranche 2

Detailed Projections: Upside Case

(CAD$ in millions)

	Quarterly Projections											Annual Projections		
	2016			2017				2018				2016	2017	2018
	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	FY	FY	FY
Oil - WTI (US$/Bbl)	$45.06	$50.00	$50.00	$55.00	$55.00	$55.00	$55.00	$60.00	$60.00	$60.00	$60.00	$44.63	$55.00	$60.00
NGL - Discount to WTI	70%	70%	70%	68%	68%	68%	68%	60%	60%	60%	60%	69%	68%	60%
AECO (C$/GJ)	$1.24	$2.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$2.02	$3.00	$3.00
Total Volumes (Boe/d)	25,517	24,699	25,492	26,393	27,028	25,943	28,125	30,668	31,616	29,382	33,314	25,518	26,872	31,245
Net Revenue	$71	$81	$91	$101	$105	$102	$113	$127	$133	$125	$144	$305	$422	$529
Total Expenses	39	41	38	43	41	41	42	45	43	42	44	158	166	174
EBITDA	$32	$40	$53	$59	$64	$61	$72	$82	$89	$82	$101	$147	$255	$355
Less: CapEx	(8)	(35)	(35)	(86)	(12)	(66)	(70)	(114)	(11)	(109)	(99)	(85)	(234)	(333)
Less: ΔNWC	(5)	21	(12)	25	(41)	40	(10)	16	(53)	73	(29)	(4)	15	7
Less: Cash Taxes	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Other	1	-	-	-	-	-	-	-	-	-	-	15	-	-
Unlevered Free Cash Flow	$20	$26	$5	($2)	$11	$35	($8)	($15)	$25	$46	($27)	$73	$36	$29
Less: Cash Interest	-	(4)	(4)	(4)	(4)	(3)	(3)	(3)	(4)	(3)	(3)	(25)	(14)	(13)
Levered Free Cash Flow	$20	$23	$1	($6)	$7	$31	($11)	($18)	$21	$43	($30)	$48	$22	$16
Plus: Credit Facility Draw	13	-	3	23	9	0	11	33	7	3	30	18	43	73
Less: Credit Facility Repayment	-	(23)	(4)	(17)	(16)	(32)	-	(15)	(28)	(46)	-	(27)	(65)	(89)
Less: Debt Repayment	(362)	-	-	-	-	-	-	-	-	-	-	(369)	-	-
Plus: Net Cash from Debt Issuance	345	-	-	-	-	-	-	-	-	-	-	345	-	-
Less: Transaction Costs & Fees	(15)	-	-	-	-	-	-	-	-	-	-	(15)	-	-
Change in Cash	$0	$0	$0	($0)	$0	$0	$0	$0	$0	($0)	$0	$0	$0	$0
Beginning Cash Balance	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Plus: Change in Cash	-	0	0	(0)	0	-	0	0	0	(0)	0	0	0	0
Ending Cash Balance	$0	$0	$0	($0)	$0	$0	$0	$0	$0	($0)	$0	$0	$0	$0
Plus: Revolver Availability	93	116	118	112	119	151	140	121	142	185	155	118	140	155
Total Liquidity	$93	$116	$118	$112	$119	$151	$140	$121	$142	$185	$155	$118	$140	$155
Ending Balances														
Revolving Credit Facility (CAD$450 million)	$345	$322	$320	$326	$319	$287	$298	$317	$296	$253	$283	$320	$298	$283
2nd Lien Notes	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Secured Debt	$345	$322	$320	$326	$319	$287	$298	$317	$296	$253	$283	$320	$298	$283
Senior Unsecured Notes	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Debt	$345	$322	$320	$326	$319	$287	$298	$317	$296	$253	$283	$320	$298	$283
Negative Working Capital	$10	$31	$19	$44	$3	$43	$34	$50	($3)	$69	$41	$19	$34	$41
Total Debt incl. Negative Working Capital	$354	$353	$339	$370	$322	$331	$332	$367	$292	$322	$323	$339	$332	$323
Net Debt incl. Negative Working Capital	$354	$353	$339	$370	$322	$331	$332	$367	$292	$322	$323	$339	$332	$323
LTM EBITDA	$195	$158	$147	$183	$215	$236	$255	$279	$304	$326	$355	$147	$255	$355
Secured Net Leverage Ratio	1.8x	2.0x	2.2x	1.8x	1.5x	1.2x	1.2x	1.1x	1.0x	0.8x	0.8x	2.2x	1.2x	0.8x
Total Net Leverage Ratio	1.8x	2.2x	2.3x	2.0x	1.5x	1.4x	1.3x	1.3x	1.0x	1.0x	0.9x	2.3x	1.3x	0.9x

Note: Does not include the impact of cash received from exercise of Upside Tranche 2

Detailed Projections: Downside Case

(CAD$ in millions)

	Quarterly Projections											Annual Projections		
	2016			2017				2018				2016	2017	2018
	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	FY	FY	FY
Oil - WTI (US$/Bbl)	$42.47	$40.00	$40.00	$40.00	$40.00	$40.00	$40.00	$40.00	$40.00	$40.00	$40.00	$38.98	$40.00	$40.00
NGL - Discount to WTI	65%	65%	65%	65%	65%	65%	65%	65%	65%	65%	65%	66%	65%	65%
AECO (C$/GJ)	$1.40	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$2.00	$1.78	$2.00	$2.00
Total Volumes (Boe/d)	25,517	24,016	23,291	22,775	22,634	21,820	21,467	21,740	22,034	20,292	20,148	24,797	22,174	21,053
Net Revenue	$70	$67	$66	$61	$61	$60	$59	$58	$59	$55	$54	$265	$241	$227
Total Expenses	39	41	38	42	40	39	39	41	39	39	38	157	160	157
EBITDA	$31	$26	$28	$19	$22	$20	$20	$17	$20	$16	$16	$107	$81	$69
Less: CapEx	(8)	(12)	(12)	(34)	(12)	(23)	(25)	(27)	(11)	(19)	(16)	(40)	(93)	(73)
Less: ΔNWC	(4)	8	(6)	16	(15)	10	2	(3)	(9)	11	(7)	(11)	13	(8)
Less: Cash Taxes	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Other	1	-	-	-	-	-	-	-	-	-	-	15	-	-
Unlevered Free Cash Flow	$20	$21	$9	$2	($5)	$8	($3)	($13)	($0)	$8	($7)	$72	$1	($12)
Less: Cash Interest	-	(4)	(4)	(4)	(5)	(5)	(5)	(5)	(6)	(6)	(6)	(25)	(20)	(23)
Levered Free Cash Flow	$20	$17	$5	($2)	($11)	$3	($9)	($18)	($6)	$3	($13)	$47	($19)	($35)
Plus: Credit Facility Draw	13	-	-	10	11	3	9	18	6	0	13	15	32	38
Less: Credit Facility Repayment	-	(17)	(5)	(8)	-	(5)	-	-	-	(3)	-	(23)	(13)	(3)
Less: Debt Repayment	(362)	-	-	-	-	-	-	-	-	-	-	(369)	-	-
Plus: Net Cash from Debt Issuance	344	-	-	-	-	-	-	-	-	-	-	344	-	-
Less: Transaction Costs & Fees	(15)	-	-	-	-	-	-	-	-	-	-	(15)	-	-
Change in Cash	$0	$0	$0	$0	($0)	($0)	($0)	$0	$0	($0)	($0)	$0	$0	($0)
Beginning Cash Balance	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Plus: Change in Cash	-	-	0	0	(0)	(0)	(0)	-	-	(0)	(0)	0	(0)	(0)
Ending Cash Balance	$0	$0	$0	$0	($0)	($0)	($0)	$0	$0	($0)	($0)	$0	($0)	($0)
Plus: Revolver Availability	94	111	116	114	103	106	97	79	73	76	63	116	97	63
Total Liquidity	$94	$111	$116	$114	$103	$106	$97	$79	$73	$76	$63	$116	$97	$63
Ending Balances														
Revolving Credit Facility (CAD$450 million)	$344	$327	$322	$324	$335	$332	$341	$359	$365	$362	$375	$322	$341	$375
2nd Lien Notes	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Secured Debt	$344	$327	$322	$324	$335	$332	$341	$359	$365	$362	$375	$322	$341	$375
Senior Unsecured Notes	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Debt	$344	$327	$322	$324	$335	$332	$341	$359	$365	$362	$375	$322	$341	$375
Negative Working Capital	$11	$19	$13	$29	$14	$24	$26	$23	$14	$25	$18	$13	$26	$18
Total Debt incl. Negative Working Capital	$356	$346	$334	$353	$348	$356	$366	$382	$379	$387	$393	$334	$366	$393
Net Debt incl. Negative Working Capital	$356	$346	$334	$353	$348	$356	$366	$382	$379	$387	$393	$334	$366	$393
LTM EBITDA	$194	$142	$107	$104	$95	$89	$81	$78	$77	$73	$69	$107	$81	$69
Secured Net Leverage Ratio	1.8x	2.3x	3.0x	3.1x	3.5x	3.7x	4.2x	4.6x	4.8x	5.0x	5.4x	3.0x	4.2x	5.4x
Total Net Leverage Ratio	1.8x	2.4x	3.1x	3.4x	3.7x	4.0x	4.5x	4.9x	4.9x	5.3x	5.7x	3.1x	4.5x	5.7x

Note: Does not include the impact of cash received from exercise of Upside Tranche 2

Deferred Tax Assets

(CAD$ in millions)

- Lightstream has tax pools with carrying value of ~CAD$1.5 billion, of which CAD$668 million are available for FY2016

Tax Pools	Carrying value	% applicable per year	$ applicable per year
Tax pools as of 12/31/15			
Canadian Development Expenses (CDE)	$820	30%	$246
Undepreciated Capital Costs (UCC)	357	25%	89
Non-capital losses and Canadian exploration expenses (CEE)	342	100%	342
Share issuance and financing costs	13	100%	13
Tax pools available for FY 2016	$1,531		$690
Less: Income tax recovery in Q1 2016	(22)		(22)
Tax pool as of 3/31/16	$1,509		$668

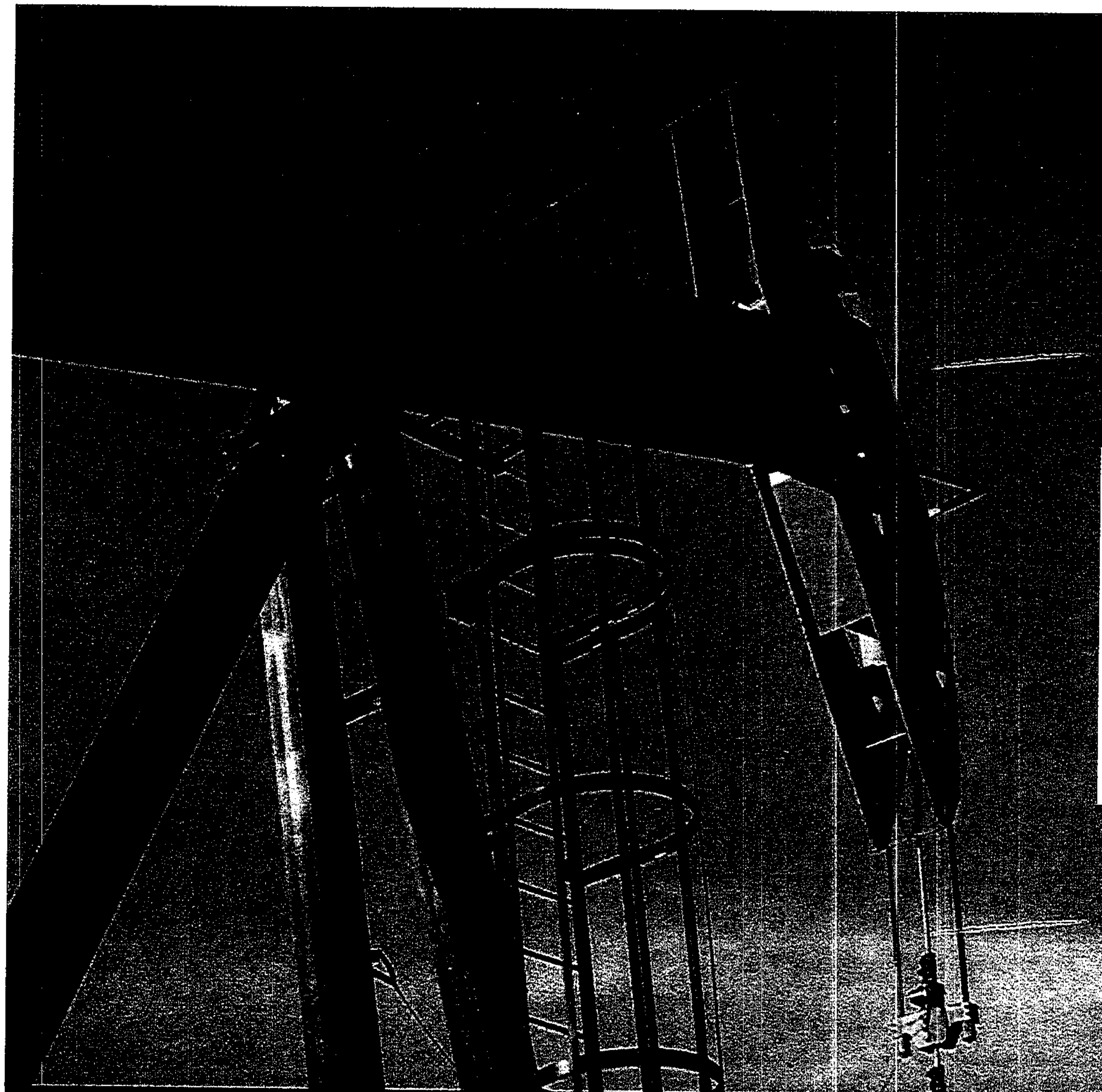
Appendix

PV-10 Sensitivity

(CAD$ in millions)

January 1, 2016 Effective Date			
	$40 WTI / $2.00 AECO	$50 WTI / $2.50 AECO	$60 WTI / $3.00 AECO
PDP	$361.0	$624.3	$894.7
PDNP / PUD	11.3	63.4	192.8
1P PV-10	$372.4	$687.6	$1,087.5
PROB	153.0	351.5	558.8
2P PV-10	$525.3	$1,039.1	$1,646.4

EXHIBIT 5 DATE Oct 31/16
WITNESS P. D. Scott
HEATHER BOWIE
COURT REPORTER

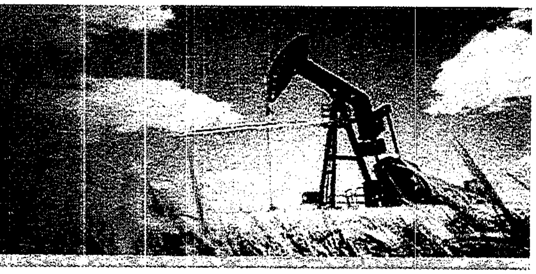


LIGHTSTREAM RESOURCES

Corporate Presentation

Q2 2016

CAUTIONARY STATEMENTS



LIGHTSTREAM RESOURCES

TSX: LTS

Forward Looking Statements. Certain information provided in this presentation constitutes forward-looking statements. Specifically, this presentation contains forward-looking statements relating to the proposed recapitalization plan and the matters related thereto, including the anticipated timing of certain events, the anticipated effects of the recapitalization plan on Lightstream, future capital structure, debt levels and liquidity position, operating plans and objectives, hedging strategies, our drilling inventory, sufficiency of cash to fund ongoing operations, our pursuit of strategic initiatives and the potential timing thereof. The forward-looking statements are based on information currently available as well as certain expectations and assumptions. Although we believe that the expectations and assumptions on which the forward-looking statements are based are reasonable, undue reliance should not be placed on the forward-looking statements because we can give no assurance that they will prove to be correct. Since forward-looking statements address future events and conditions, by their very nature they involve inherent risks and uncertainties. Actual results could differ materially from those currently anticipated due to a number of factors and risks. These include, but are not limited to inability to implement the recapitalization plan on the timeline or on the terms currently contemplated or at all, the Recapitalization may have an effect on the Company other than what is currently anticipated, the proposed timing of such strategic initiatives, commodity price and exchange rate fluctuations, risks associated with the oil and gas industry in general (e.g., operational risks in production; delays or changes in plans with respect to capital expenditures; the uncertainty of reserve estimates; the uncertainty of estimates and projections relating to production, costs and expenses, reliance on industry partners, availability of equipment and personnel, changes in applicable regulatory regimes and health, safety and environmental risks)and general economic conditions. Certain of these risks are set out in more detail in our Annual Information Form which has been filed on SEDAR and can be accessed at www.sedar.com. Except as may be required by applicable securities laws, Lightstream assumes no obligation to publicly update or revise any forward-looking statements made herein or otherwise, whether as a result of new information, future events or otherwise.

Non-GAAP measures. This presentation contains financial terms that are not considered measures under International Financial Reporting Standards ("IFRS"), such as EBITDA, capital expenditures, funds flow from operations, total debt, operating netback and operating netback after hedging. Profitability relative to commodity prices per unit of production is demonstrated by an operating netback. Operating netback reflects revenues less royalties, transportation costs, and production expenses divided by production for the period and operating netback including hedging reflects the impact of crude oil and natural gas derivative contracts on the operating netback. These measures do not have any standardized meaning prescribed by IFRS and therefore may not be comparable to those reported by other companies. These measures are commonly utilized in the oil and gas industry and are considered informative for management and stakeholders as they help evaluate performance and demonstrate the ability to generate sufficient cash to fund future growth opportunities, pay dividends and repay debt. These measures should not be viewed as an alternative to cash flow from operations, net income or other measures of financial performance calculated in accordance with IFRS. Further information and reconciliations to the most directly comparable IFRS financial measures in respect of these non-GAAP measures is set forth in our MD&A.

Reserves information. Unless indicated otherwise, reserve estimates and related future net revenue and other reserves information is derived from Lightstream's independent reserve report prepared by Sproule Associates Limited as at December 31, 2015 using forecast prices and costs.

Boe presentation. Natural gas volumes have been converted to barrels of oil equivalent ("boe"). Six thousand cubic feet ("Mcf") of natural gas is equal to one barrel of oil equivalent based on an energy equivalency conversion method primarily attributable at the burner tip and does not represent a value equivalency at the wellhead. Boes may be misleading, especially if used in isolation.

Oil and gas metrics. This presentation contains metrics commonly used in the oil and natural gas industry, such as "recycle ratio", "finding and development costs or F&D" and "estimated ultimate recovery or EUR". These terms do not have a standardized meaning and may not be comparable to similar measures presented by other companies, and therefore should not be used to make such comparisons. F&D cost is the sum of capital expenditures incurred in the period and the change in future development capital required to develop reserves. F&D cost per boe is determined by dividing current period net reserve additions into the corresponding period's F&D cost. The Company uses F&D costs, both including and excluding acquisitions and dispositions, as a measure of the efficiency of its overall capital program including the effect of acquisitions and dispositions. Recycle ratio is measured by dividing the operating netback by the F&D costs per boe for the year and is used to determine profitability. EUR represents the estimated ultimate recovery associated with the type curves presented which are based on the assumptions used by Sproule Associates Limited to estimate Lightstream's proved plus probable reserves per well as evaluated effective December 31, 2015 based on forecast prices and costs. There is no certainty that Lightstream will ultimately recover such volumes from the wells it drills. Management uses these oil and gas metrics for its own performance measurements and to provide shareholders with measures to compare Lightstream's operations over time. Readers are cautioned that the information provided by these metrics, or that can be derived from the metrics presented in this presentation, should not be relied upon for investment or other purposes.

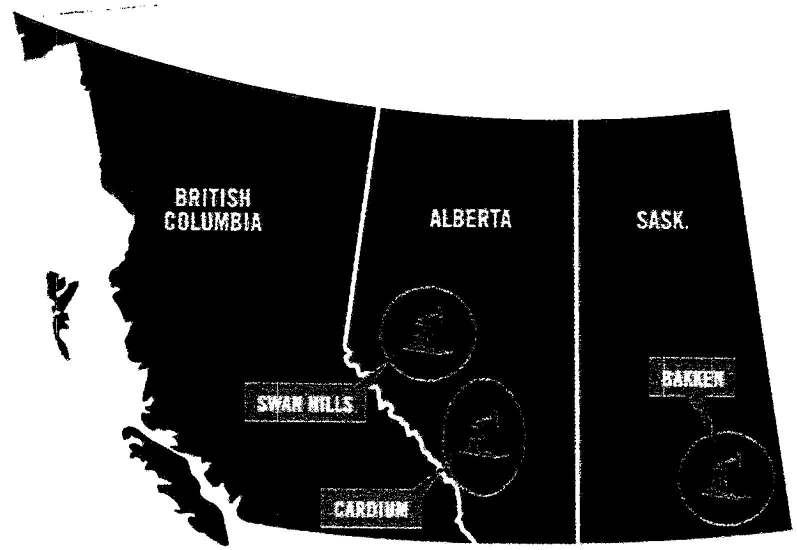
Drilling locations. This presentation discloses drilling locations in three categories: proved locations; probable locations; and unbooked locations. Proved locations and probable locations are sometimes collectively referred to as "booked locations", and are derived from Lightstream's most recent independent reserves evaluation and account for drilling locations that have associated proved plus probable reserves or probable-only reserves, as applicable. Unbooked locations as disclosed herein have been identified by management as an estimation of the Company's multi-year drilling activities using information including evaluation of applicable geologic, seismic, engineering, production, pricing assumptions and reserves information. The reserves and resources in the unbooked locations meet the classifications of possible reserves and contingent resources under the COGE Handbook. There is no certainty that Lightstream will drill all unbooked drilling locations and, if drilled, there is no certainty that such locations will result in additional oil and gas reserves, resources or production.

OUR ASSET BASE

LIGHTSTREAM RESOURCES

TSX: LTS

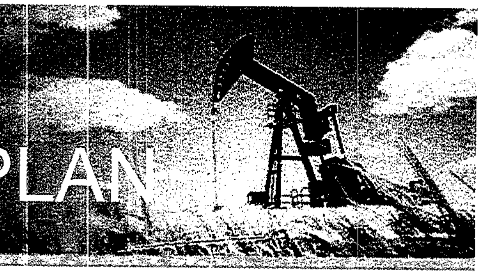
We have a current inventory of over 1,550 drilling locations and are prepared to execute a drilling program following implementation of our Recapitalization plan and when macro economic conditions (commodity prices and costs) support investment



Business Units	Q2 2016 Production (boepd)	1H 2016 Production (boepd)	Booked and Unbooked Locations[1]
Bakken	8,939	9,234	>1,000
Cardium	14,655	14,666	>430
AB / BC	1,522	1,833	>120
Total	25,116	25,733	>1,550

1. Booked and unbooked locations revised to reflect current economic conditions and land expirations

PROPOSED RECAPITALIZATION PLAN



LIGHTSTREAM RESOURCES

TSX: LTS

Our proposed recapitalization is intended to be implemented by way of a corporate plan of arrangement under the *Canada Business Corporations Act* (CBCA) that will result in Secured and Unsecured Notes being converted to equity

The plan of arrangement is subject to a number of conditions[1]. If implemented there would be ~100 million shares outstanding and 2 new series of warrants:

Common Shares — Existing Common Shares will be consolidated and exchanged

- Existing holders will receive an aggregate of ~2.25 mm new common shares (~88 existing common shares to 1 new common share)
- Existing holders will receive a total of ~7.75 mm Series 2 warrants to purchase new common shares
- The Series 2 warrants will be exercisable over 5 years and have a sliding scale exercise price between $12.88 and $14.96 per new common share

Secured Notes — Will be converted or exchanged; entitled to participate in new offering

- Existing secured noteholders will receive an aggregate of ~95 mm new common shares
- All eligible secured noteholders will be entitled to participate in a new secured notes offering of ~US$39.3 mm principal amount of 12% second lien notes
- Under a support agreement, holders of 91.5% of outstanding secured notes have agreed, subject to certain conditions, to vote their securities in favour of the plan of arrangement

Unsecured Notes — Will be exchanged

- Existing unsecured noteholders will receive an aggregate of ~2.75 mm new common shares
- Existing noteholders will receive ~5 mm Series 1 warrants to purchase new common shares
- The Series 1 warrants will be exercisable for a period of 5 years and have a sliding scale exercise price between $10.25 and $11.77 per new common share

New Bank Financing — Will replace existing credit facility

- New $400 million borrowing base loan with a syndicate of lenders
- Semi-annual borrowing base determinations with the first determination by December 15, 2016

1. If the Unsecured Noteholder litigation is not settled in a manner satisfactory to both the Company and the ad hoc committee of certain Secured Noteholders on or before September 16, 2016, or if the recapitalization does not receive the requisite approval of each class of securityholders at their respective meetings, the Company will discontinue the CBCA process and commence alternative proceedings under the *Companies' Creditors Arrangement Act* ("CCAA") as outlined in our September 9, 2016 press release.

DEBT COMPOSTION UNDER PROPOSED RECAPITALIZATION PLAN

LIGHTSTREAM RESOURCES

TSX: LTS

Assuming implementation of the Recapitalization plan, we expect to have at least $80 million of available liquidity after payment of closing fees and other costs

Term Secured Credit Facility[1]
$400 million

~$278[2] million drawn pro forma Q2 2016

Term Secured 2nd Lien Notes
US$39.2 million (12.0%)

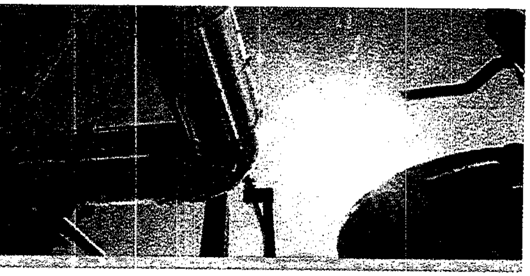
~$50 million

MATURITY DATE

2016 2018 2020

1. The borrowing is subject to re-determination on a semi-annual basis with the next review scheduled for December 2016
2. Amount drawn is based on pro forma Q2 financial statements included in the Company's Information Circular dated August 29, 2016 and includes issued letters of credit. It assumes cash balances at June 30, 2016 and the proceeds from the new 2nd lien notes offering are used to reduce the amount outstanding. Does not reflect impact of funding recapitalization costs

1H 2016 GUIDANCE



LIGHTSTREAM RESOURCES

TSX: LTS

1H 2016 results were in line with or better than forecasted

('000s, except where noted and per share amounts)	1H 2016 Revised Guidance (May 4, 2016)	1H Actual Results
Production (Six month average)		
Total (boe/d)	25,500 – 26,000	**25,733**
Light-oil and liquids weighting	66%	**66%**
EBITDA	$56,000	**$60,146**
Funds Flow from Operations	($10,000)	**($6,823)**
Funds Flow per share[1]	($0.05)	**($0.03)**
Capital expenditures[2]	$15,500 – $16,500	**$14,857**
Economic Parameters	Q2 2016	**Q2 2016**
Crude oil – WTI (US$/bbl)	45.00	**45.59**
Crude oil – WTI (Cdn$/bbl)	58.44	**58.76**
Corporate light-oil to WTI differential[3] (US$/bbl)	6.19	**4.73**
AECO gas price (Cdn$/bbl)	1.37	**1.40**
Foreign exchange rate (Cdn$/US$)	0.77	**0.78**

We will not be providing guidance for the second half at this time due to the pending Recapitalization plan.

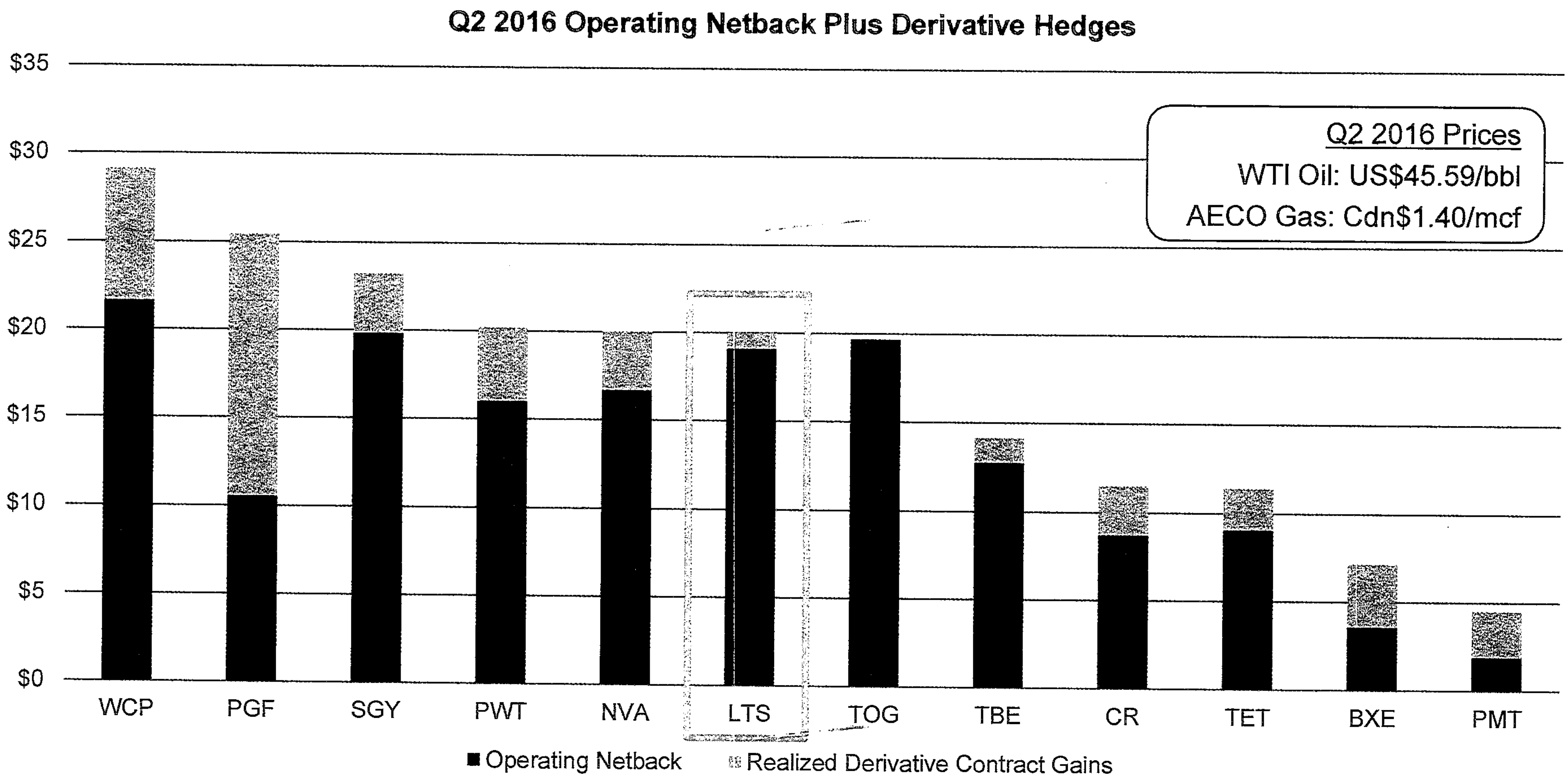
1. Funds Flow per share calculation based on 198 million weighted average shares outstanding
2. Projected capital expenditures exclude acquisitions and divestitures, which are evaluated separately
3. Differential includes approximately US$2.00/bbl cost for tariffs and quality adjustments charges from western Canadian benchmark prices to our realized wellhead prices

Q2 2016 NETBACKS & HEDGING EFFECTS

LIGHTSTREAM RESOURCES

TSX: LTS

In Q2 2016, we realized a ~$2 million gain on crude oil and natural gas derivative contracts for a total operating netback of $20.00/boe



*Data from peer Q2 2016 financial reports and is calculated using operating netback and realized gain (loss) on derivative contracts

FUNDS FLOW PROTECTION

LIGHTSTREAM RESOURCES

TSX: LTS

Our 2016 crude oil hedge position:

Commodity	2H 2016
Light oil: WTI (bbl/d)	1,250
Fixed Price Swap ($US/bbl)	$49.40
Light oil diff: Edm Sweet (bbl/d)	3,000
WTI – Edm Sweet ($US/bbl)	$3.80
Natural gas: AECO (mcf/d)	~4,740
Fixed Price Swap ($Cdn/Mcf)	$3.08

- We plan to increase our hedge position after implementation of our proposed Recapitalization plan
- We aim to hedge 25% - 50% of net production
  - ~10% of net liquids production[1,2] hedged for 2H 2016
- 1H 2016 cash proceeds on crude oil and natural gas derivative contracts were ~$8 million[3]

Estimated Cash Proceeds from Hedging for Remainder of 2016					
WTI Prices	US$25/bbl	US$30/bbl	US$35/bbl	US$40/bbl	US$45/bbl
Hedge proceeds[3]	$8.7MM	$7.2MM	$5.6MM	$4.1MM	$2.6MM

1. Net production (less royalties of 10%), 66% liquids weighting
2. Based on Q2 2016 production and Cdn$/US$ exchange rate of $0.77
3. All hedge proceeds stated in Cdn$

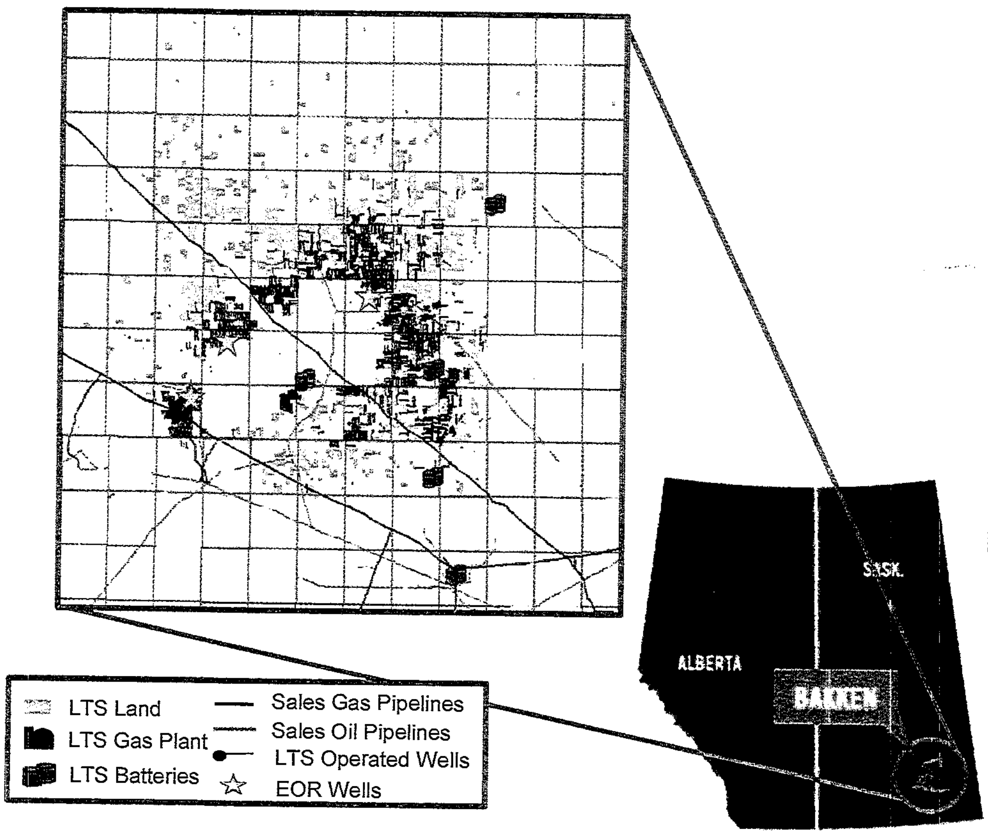
BAKKEN ASSETS

LIGHTSTREAM RESOURCES

TSX: LTS

Focus on optimization and EOR

Our assets produce light oil from the Bakken and the conventional Mississippian formations with a relatively low decline rate. In 2016 we continued to focus on optimizing and expanding our natural gas EOR projects in the Bakken. We have an extensive network of facilities that allows us to control operating costs.



Business Unit Results	Bakken [1] Q2 2016	1H 2016
Average Production (boepd)	8,939	9,234
Oil/Liquids Weighting	94%	94%
Operating Income ($ million)	21	32
Capex ($ million)	5	9
Free Cash Flow ($ million)	16	23
2015 2P Reserves (mmboe)	63	
Upside Opportunities [1]		
Undeveloped Land (sections)	235	
Booked and Unbooked locations	>1,000	

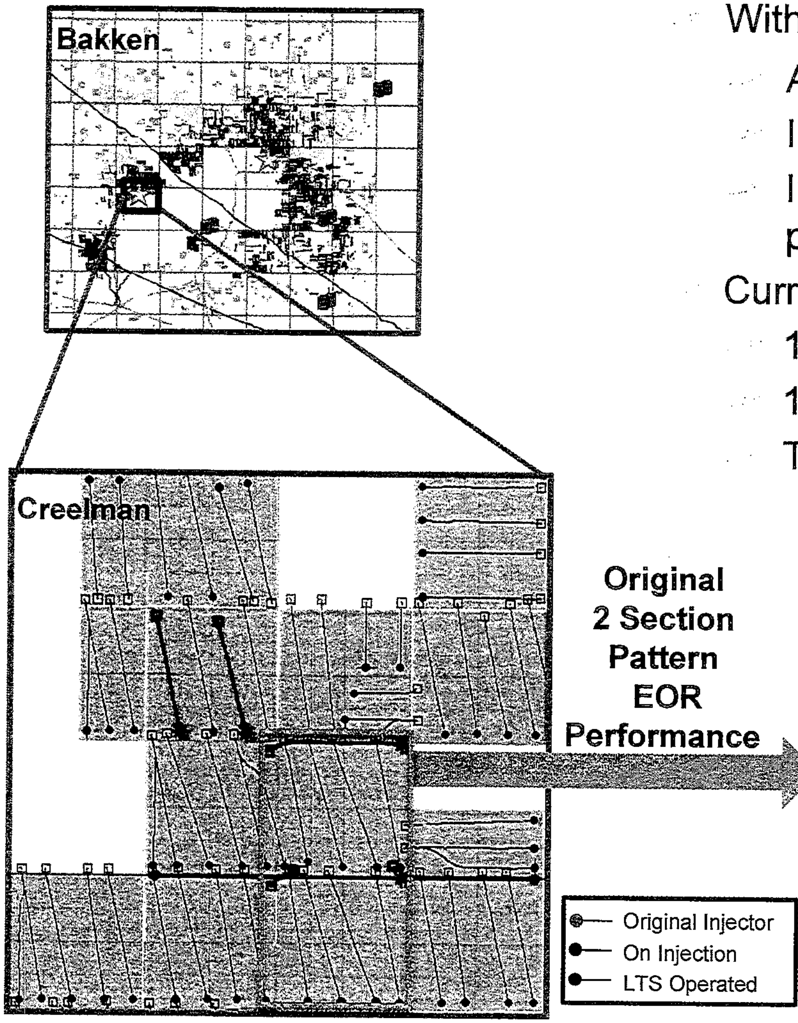
1. Includes conventional Mississippian

IMPROVING TIGHT OIL RECOVERIES

LIGHTSTREAM RESOURCES

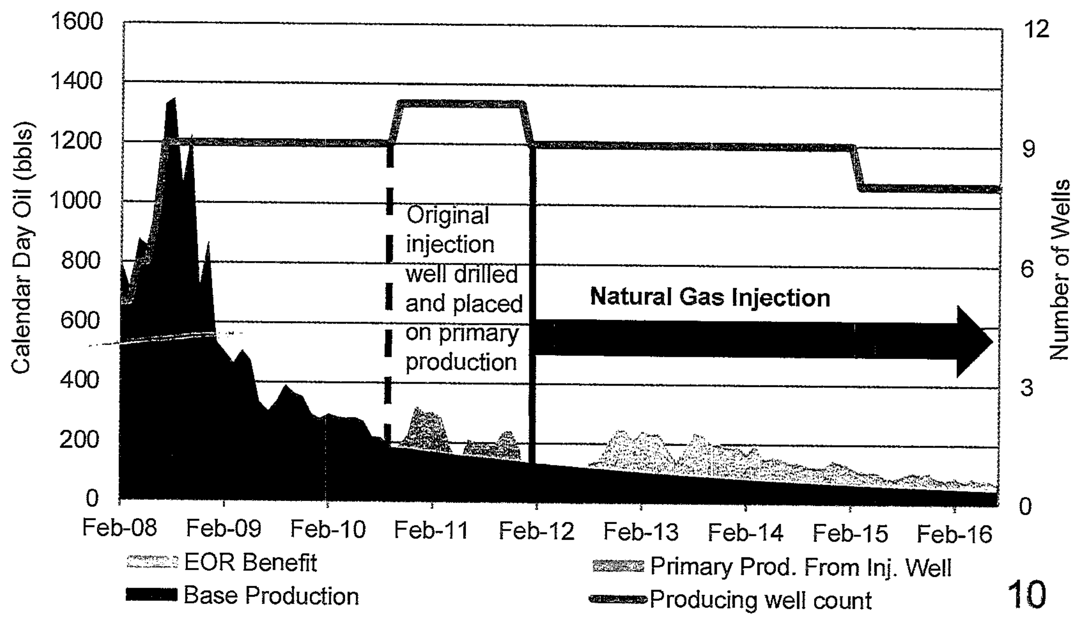
TSX: LTS

Future value generation through natural gas flooding



Original 2 Section Pattern EOR Performance

- With Bakken EOR projects we expect to:
  - Attenuate declines and extend production life
  - Increase DPIIP recovery factors from 15% to potentially >25%
  - Improve economic returns with high production-to-injector well ratios
- Current EOR projects:
  - 13 section Creelman EOR Unit
  - 1 section Midale EOR Unit
  - Total of 7 wells are on gas injection in the Bakken



CARDIUM ASSETS

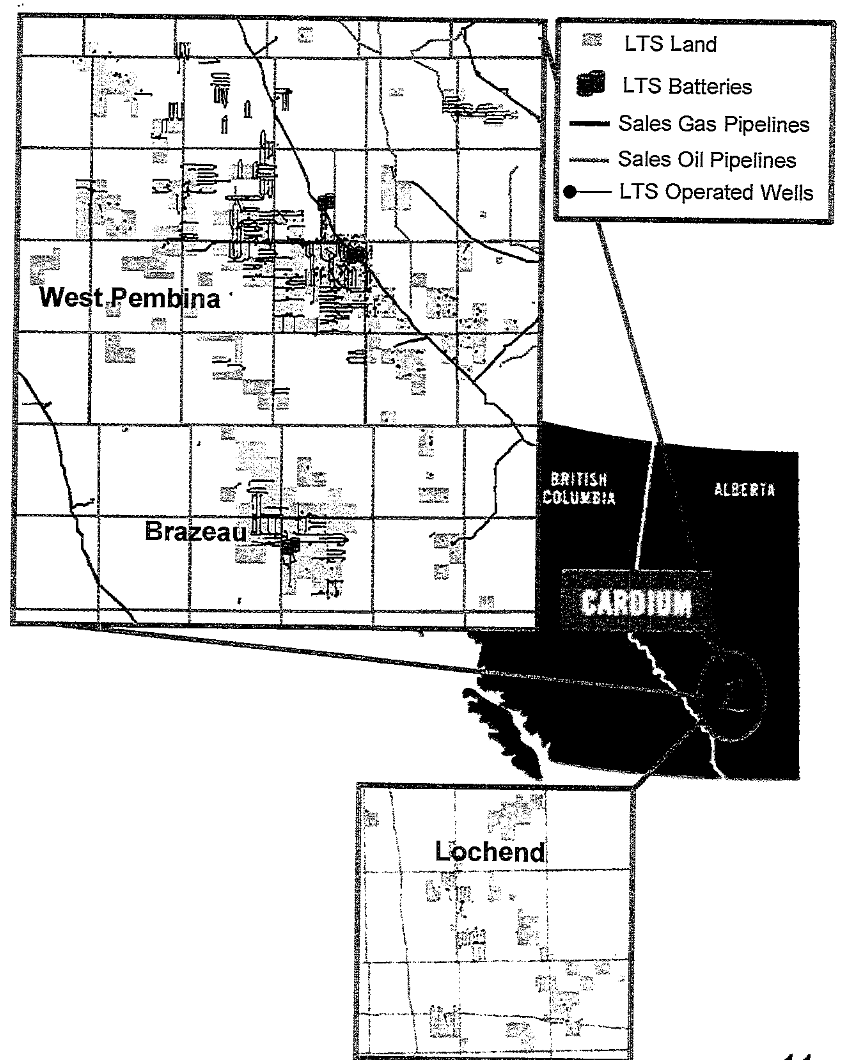
LIGHTSTREAM RESOURCES

TSX: LTS

Generating positive operating cash flow

Our extensive land base stretches from southwest of Calgary to northwest of Edmonton and our assets produce light oil from the Cardium formation. We initiated water injection for EOR in July 2014. This is an active area for industry, with multi-zone potential.

Business Unit	Cardium	
Results	Q2 2016	1H 2016
Average Production (boepd)	14,655	14,666
Oil/Liquids Weighting	49%	50%
Operating Income ($ million)	23	40
Capex ($ million)	1	1
Free Cash Flow ($ million)	22	39
2015 2P Reserves (mmboe)	66	
Upside Opportunities		
Undeveloped Land (sections)	127	
Booked and Unbooked locations	>430	



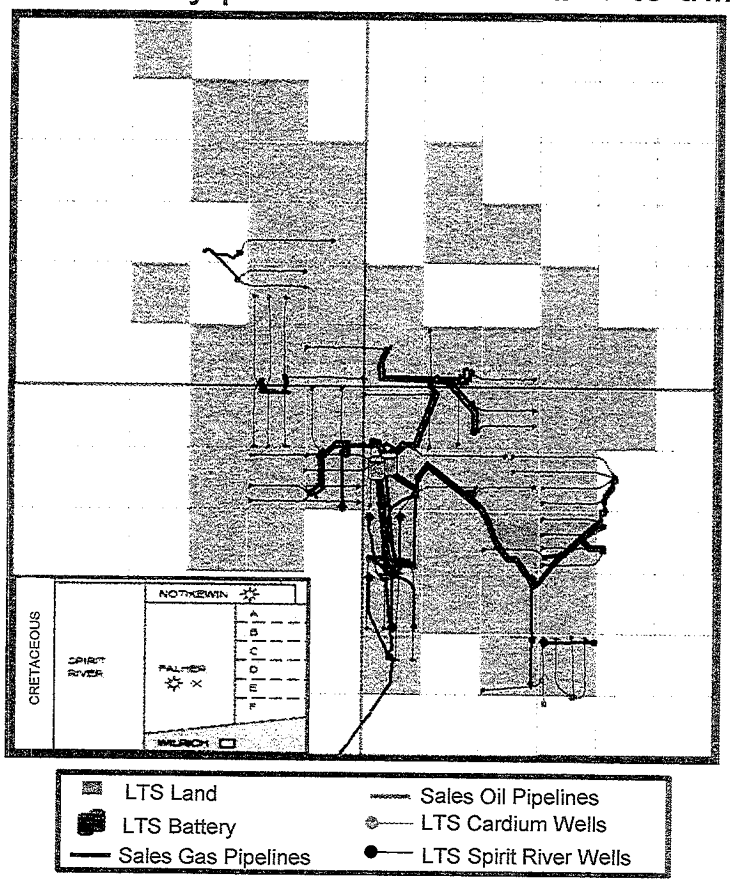
SPIRIT RIVER DEVELOPMENT

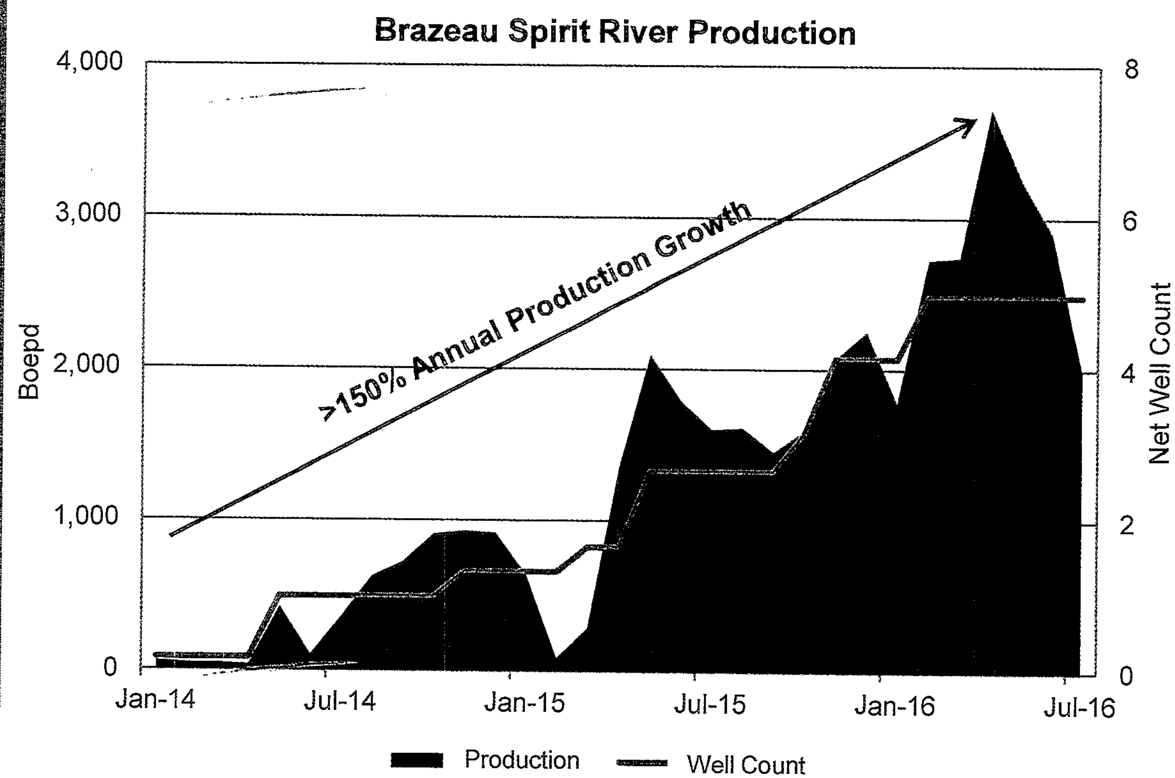
LIGHTSTREAM RESOURCES

TSX: LTS

By utilizing existing Cardium infrastructure, we achieve cost optimization

- We have 5 net liquids-rich Falher gas wells on production
- Stacked play potential with Notikewin and Falher
- Capital efficiencies of approximately $8,800/boepd and F&D cost of $6.10/boe
- July production down due to third party pipeline restrictions





AB / BC ASSETS

LIGHTSTREAM RESOURCES

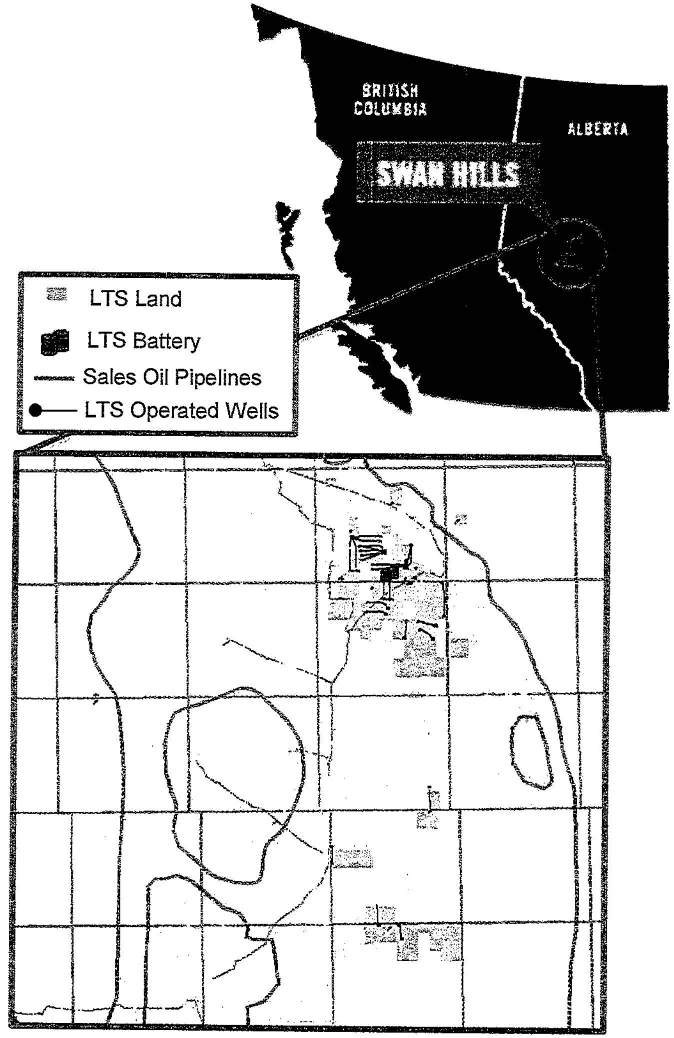
TSX: LTS

The Swan Hills provides us with another growth platform

- Light-oil play
- Proved productive capacity with infrastructure for growth
- Reserve bookings confirm long-term prospectivity
- Implemented EOR water flood in Q2 2016
  - Injecting into 2 wells on a 4-well pad
  - Increase DPIIP recovery factors from 15% to potentially >25%
- Previous third party restrictions of ~400 boepd were rectified early in Q3

Business Unit	AB / BC[1]		Swan Hills	
Results	Q2 2016	1H 2016	Q2 2016	1H 2016
Average Production (boepd)	1,522	1,833	643	946
Oil/Liquids Weighting	51%	56%	100%	97%
Operating Income ($ million)	(0.5)	(1.3)	~~0.9~~	1.4
Capex ($ million)	1	5	0	2
2015 2P Reserves (mmboe)	13		10	
Upside Opportunities				
Undeveloped Land (sections)	424		102	
Booked and Unbooked locations	>120		>75	

1. AB/BC includes Swan Hills



LONG-TERM WELL ECONOMICS

LIGHTSTREAM RESOURCES

TSX: LTS

We focus on well economics that reinforce our business model with quick payouts and strong capital efficiencies

< 2 year capital payout

> 2 recycle ratio

Business Unit Type Well	Bakken Business Unit		Cardium			Alberta/BC
	Bakken	**Mississippian**	**Brazeau**	**W. Pembina**	**Falher**	**Swan Hills**
Drill, Complete, Equip, Tie-in ($ million)[1]	1.4	0.8	2.8	2.6	3.4	3.8
Netback ($/boe)	33.73	30.81	26.67	32.39	12.70	26.86
EUR (Mboe)[2]	86	59	241	186	723	242
F&D ($/boe)	15.69	14.18	11.65	14.20	4.65	15.54
Recycle Ratio	2.1	2.2	2.3	2.3	2.7	1.7
Payout (years)	1.3	1.0	2.3	2.0	1.0	2.7
Net Locations (included in reserve report)	259	34	42	67	1	39
Net Locations (with no reserves assigned)	546	175	60	105	25	39

Assumptions:
US $50/bbl WTI, AECO gas price $2.50/Mcf, foreign exchange rate of Cdn$/US$ $0.75, light-oil weighted differential of US$6/bbl, before tax, excludes land costs
Well counts are based on formation locations and are prioritized to what we would drill today

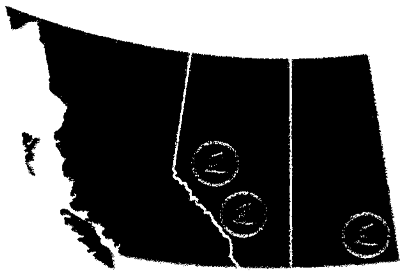
1. Estimated capital costs based on the commodity price forecast environment
2. Internal estimates

LIGHTSTREAM TODAY

LIGHTSTREAM RESOURCES

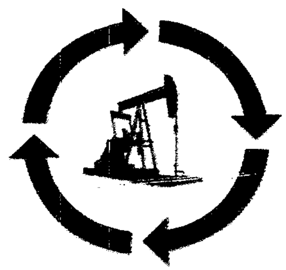
TSX: LTS

EXTENSIVE ASSETS



- Extensive drilling inventory
- Undeveloped land of ~ 503,000 acres
- 142 million boe of 2P reserves

PRESERVE LONG TERM VALUE



- Recapitalization plan avoids selling assets in low commodity price environment
- Current economic conditions warrant drilling program upon completion of the Recapitalization plan

SHORT-TERM STRATEGY

- Continue normal course operations
- CBCA Recapitalization Plan
  - Meeting of shareholders and noteholders scheduled for September 30, 2016

LIGHTSTREAM
RESOURCES

Trading Symbol LTS: TSX

Share Price (Sep 8, 2016)	$0.12	Market Capitalization	$24 million
Shares Outstanding (Jun 30, 2016 Basic)	199 MM	Total Debt (Jun 30, 2016)	$1.57 billion
Options/Incentive shares (Jun 30, 2016)	8.5 MM	Enterprise Value	$1.81 billion
Shares Traded Daily (Q2 2016)	708 M		

EIGHTH AVENUE PLACE • 2800, 525 - 8TH AVENUE SW • CALGARY, ALBERTA • T2P 1G1 • (403) 268-7800
WWW.LIGHTSTREAMRESOURCES.COM

Bennett Jones

Bennett Jones LLP
3400 One First Canadian Place, PO Box 130
Toronto, Ontario, Canada M5X 1A4
Tel: 416.863.1200 Fax: 416.863.1716

Sean H. Zweig
Partner
Direct Line: 416.777.6254
e-mail: zweigs@bennettjones.com

September 30, 2016

Via E-Mail

Mr. Deryck Helkaa and Mr. Dustin Olver
FTI Consulting Inc.
Suite 720
440 2nd Ave SW
Calgary AB T2P 5E9

Mr. Sean F. Collins and Mr. Walker MacLeod
McCarthy Tétrault LLP
Suite 4000
421 7th Ave SW
Calgary AB T2P 4K9

Dear Sirs:

Re: Lightstream Resources Ltd., et al (the "Company")

Thank you for taking the time to speak to us on Wednesday afternoon about our various concerns with respect to the Initial Order and the Company's CCAA proceeding generally. Further to that discussion, we would appreciate the following, most of which we discussed on our call:

1. The Monitor's views on what would be involved in the preparation of a report from the Monitor to fully consider and report to the Court with respect to all of the Company's available restructuring alternatives in the circumstances. As discussed, in light of various factors, including the Company's liquidity position (and the rising commodity pricing environment – including that WTI is at US$48 as of the time of this letter), we do not believe that the proposed single track sale process is appropriate in the circumstances, and the Company should instead be exploring any and all alternatives to maximize value for creditors.

2. The Monitor's views as to the appropriateness of the 5% discount to strip pricing used for purposes of the Company's weekly cash flow statement. In addition, what date's strip pricing was used? Could the Monitor please prepare a revised cash flow statement at current strip pricing (with and without the 5% discount), as well as reasonable sensitivities off of current strip pricing?

EXHIBIT 7 DATE Oct 3/16
WITNESS P. D. Scott
HEATHER BOWIE
COURT REPORTER

3. Whether you were able to persuade the Company to instruct TD Securities Inc. to speak with us next week about the strategic process the Company has undergone, including with respect to the sale process launched at the time the CBCA proceeding was commenced. We understood that you thought it would be a good idea, and that you would be speaking to the Company about that.

4. Detailed back-up and calculations with respect to the Directors' Charge, the KERP Charge, the KEIP Charge and the FA Charge, as well as a detailed explanation of each of the Company's financial advisor's proposed role in the CCAA proceeding.

We look forward to hearing from you on these matters as soon as possible, and preferably today. As you know, we are examining the Company's affiant on Monday morning, and we would like the benefit of the foregoing in advance of that.

Yours truly,
BENNETT JONES LLP

Sean H. Zweig

SHZ
cc: Kevin Zych
Chris Simard
Tim Pinos
Kelly Bourassa