ANNUAL INFORMATION FORM

For the Year Ended December 31, 2012

Dated March 19, 2013

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DEFINITIONS

Unless the context indicates otherwise, the following terms shall have the meanings set out below when used in this Annual Information Form. Certain other terms and abbreviations used herein, but not defined herein, are defined in NI 51-101 or the COGE Handbook and, unless the context otherwise requires, shall have the same meanings herein as in NI 51-101 or the COGE Handbook.

"**2008 Bid**" means the normal course issuer bid announced by the Corporation in June 2008 through the facilities of the TSXV to acquire for cancellation up to 864,329 Common Shares;

"**771129**" means 771129 Alberta Ltd., a corporation organized under the ABCA and the Corporation's wholly-owned subsidiary;

"**744997**" means 744997 Alberta Ltd., a corporation organized under the ABCA and a predecessor to the Corporation by amalgamation;

"**ABCA**" means the *Business Corporations Act*, R.S.A. 2000, c. B-9, as amended;

"**AIF**" means this Annual Information Form;

"Audit Committee" means the audit committee of the Corporation

"**Board of Directors**" or "**Board**" means the board of directors of the Corporation;

"**Breaker**" means Breaker Energy Ltd., a publicly traded oil and natural gas company acquired by NAL Oil & Gas Trust in December 2009;

"**COGE Handbook**" means the Canadian Oil and Gas Evaluation Handbook prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum;

"**Common Shares**" means the common shares of the Corporation;

"**Corinthian**" means Corinthian Energy Corp., a private corporation, originally incorporated under the ABCA and amalgamated with a wholly-owned subsidiary of the Corporation to form Breaker Resources Ltd.;

"**Corinthian Acquisition**" means the indirect acquisition by the Corporation on July 9, 2010 of all of the issued and outstanding shares of Corinthian;

"Corinthian Acquisition Agreement" means the agreement entered into by the Corporation and Corinthian dated June 21, 2010 whereby the Corporation agreed to acquire all of the issued and outstanding common shares of Corinthian for consideration of 0.4 Common Shares of the Corporation for every one common share of Corinthian for a total consideration of approximately 16 million Common Shares;

"Corinthian Shares" means common shares of Corinthian;

"**Corporation**" or "**Surge**" means Surge Energy Inc., a corporation amalgamated under the ABCA;

"**Credit Facility**" means the $290 million extendible revolving term credit facility, as amended from time to time, of the Corporation with a banking syndicate led by National Bank of Canada and including the Bank of Nova Scotia, the Canadian Imperial Bank of Commerce, the Alberta Treasury Branches, and JP Morgan Chase Bank, N.A. and bearing interest at bank rates;

"**Crystal Lake**" means Crystal Lake Resources Inc. originally incorporated under the ABCA and amalgamated with a wholly-owned subsidiary of the Corporation to form Breaker Resources Ltd;

"**Crystal Lake Acquisition**" means the indirect acquisition by the Corporation on July 19, 2010 of all of the issued and outstanding shares of Crystal Lake;

"DPIIP" means Discovered Petroleum Initially In Place which is defined as that quantity of oil that is estimated, as of a given date, to be contained in known accumulations prior to production. The recoverable portion of DPIIP includes production, reserves, and contingent resources; the remainder is unrecoverable. There is no certainty that it will be commercially viable to produce any portion of the resources. A recovery project cannot be defined for this volume of DPIIP at this time, and as such it cannot be further sub-categorized.

"**FT Units**" means units issued pursuant to a private placement that took place in conjunction with the Recapitalization, with each unit consisting of one Common Share issued on a "flow-through" basis in accordance with the Tax Act and one Performance Warrant;

"**NAFTA**" means the North American Free Trade Agreement;

"**NI 51-101**" means National Instrument 51-101 - Standards of Disclosure for Oil and Gas Activities;

"**Offering**" means the private placement offering of 8,001,000 Subscription Receipts at a price of $5.25 per Subscription Receipt completed of October 20, 2010;

"**Partnership**" means Zapata Limited Partnership, an Alberta limited partnership which was dissolved on January 2, 2011;

"**Performance Warrant**" means a Common Share purchase warrant entitling the holder to purchase one Common Share at a price of $5.17 for a period of five years, issued pursuant to the private placement that took place in conjunction with the Recapitalization;

"**Pradera**" means Pradera Resources Inc., a private corporation incorporated under the ABCA and amalgamated with a wholly-owned subsidiary of the Corporation to form Surge Oil Inc.;

"**Pradera Acquisition**" means the indirect acquisition by the Corporation on January 6, 2012 of all of the issued and outstanding shares of Pradera;

"**Pradera Acquisition Agreement**" means the agreement entered into by the Corporation and Pradera dated December 15, 2011 whereby the Corporation agreed to acquire all of the issued and outstanding common shares of Pradera for consideration of approximately $106 million, consisting of 7.9 million Common Shares and approximately $33 million in cash including the assumption of net debt;

"**Preferred Shares**" means the preferred shares of the Corporation;

"**Recapitalization**" means the change of officers and directors and the private placement of the Corporation conducted pursuant to the Recapitalization Agreement;

"**Recapitalization Agreement**" means the reorganization and investment agreement dated March 24, 2010 among the Corporation and P. Daniel O'Neil, Maxwell Lof, Daniel C. Brown and Paul Colborne;

"**Sproule**" means Sproule Associates Limited, independent oil and gas reservoir engineers;

"**Sproule Report**" means the independent engineering report dated February 29, 2012 and effective December 31, 2011 prepared by Sproule evaluating the oil, NGL and natural gas reserves attributable to the properties of the Corporation;

"**Subscription Receipt Agreement**" means the subscription receipt agreement dated October 20, 2010 between the Corporation, Olympia Trust Company as escrow agent and a syndicate of underwriters governing the terms and conditions of the Subscription Receipts;

"Subscription Receipts" means the subscription receipts of the Corporation that were issued pursuant to the Offering and the Subscription Receipt Agreement;

"**Tax Act**" means the *Income Tax Act* (Canada), R.S.C. 1985, c.l. (5th Supp.), as amended, including the regulations promulgated thereunder;

"**Transitional Program**" means the optional five-year transitional royalty program announced by the Alberta Government on November 19, 2008 and November 24, 2008;

"**TSX**" means the Toronto Stock Exchange;

"**TSXV**" means the TSX Venture Exchange;

"**Units**" means units issued pursuant to a private placement that took place in conjunction with the Recapitalization, with each unit consisting of one Common Share and one Performance Warrant;

"**Valhalla Asset Acquisition**" means the acquisition of the Valhalla Assets by the Corporation from the Vendor pursuant to the Valhalla Purchase Agreement which was completed on November 1, 2010;

"**Valhalla Assets**" has the same meaning as is ascribed to the term "Assets" in the Valhalla Purchase Agreement;

"**Valhalla Purchase Agreement**" means the definitive agreement of purchase and sale dated September 22, 2010 between the Corporation and the Vendor relating to the acquisition by the Corporation of the Valhalla Assets; and

"**Vendor**" means the vendors of the Valhalla Assets pursuant to the Valhalla Purchase Agreement.

ABBREVIATIONS AND CONVERSION

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

Oil and Natural Gas Liquids

bbl	Barrel
bbls	Barrels
Mbbls	thousand barrels
MMbbls	million barrels
Mstb	1,000 stock tank barrels
bbl/d	barrels per day
NGLs	natural gas liquids
stb	stock tank barrel

Natural Gas

Mcf	thousand cubic feet
MMcf	million cubic feet
Mcf/d	thousand cubic feet per day
MMcf/d	million cubic feet per day
MMBtu	million British Thermal Units
Bcf	billion cubic feet
GJ	gigajoule

The following table sets forth certain standard conversions from Standard Imperial Units to the International System of Units (or metric units).

To Convert From	To	Multiply By
Mcf	Cubic metres	28.174
Cubic metres	Cubic feet	35.494
Bbls	Cubic metres	0.159
Cubic metres	Bbls	6.293
Feet	Metres	0.305
Metres	Feet	3.281
Miles	Kilometres	1.609
Kilometres	Miles	0.621
Acres	Hectares	0.405
Hectares	Acres	2.50
Gigajoules	MMbtu	0.950
MMbtu	Gigajoules	1.0526

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 35.1° API or greater is generally referred to as light crude oil. Liquid petroleum with a specified gravity of 25.8° to 35° API or greater is generally referred to as medium crude oil. Liquid petroleum with a specified gravity of 25.7° API or lower is generally referred to as heavy crude oil.
BOE	barrel of oil equivalent on the basis of 1 BOE to 6 Mcf of natural gas. BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of 1 BOE for 6 Mcf is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead
BOE/d	barrel of oil equivalent per day
m3	cubic metres
MBOE	1,000 barrels of oil equivalent
$000s	thousands of dollars
M$	thousands of dollars
MM$	millions of dollars
WTI	West Texas Intermediate, the reference price paid in U.S. dollars at Cushing, Oklahoma for crude oil of standard grade

NON-IFRS MEASURES

This AIF contains the term “netback” which is not defined by IFRS and therefore may not be comparable to performance measures presented by others. In this AIF, "netback" is calculated by deducting royalties paid and production costs, including transportation costs, from prices received, excluding the effects of hedging. Management believes that in addition to net income, netbacks are a useful supplemental measure as it assists in the determination of the Corporation's operating performance. Readers should be cautioned, however, that this measure should not be construed as an alternative to both net income and net cash from (used in) operating activities, which are determined in accordance with IFRS, as indicators of the Corporation's performance.

NOTES ON RESERVES DATA AND OTHER OIL AND NATURAL GAS INFORMATION

Caution Respecting Reserves Information

The determination of oil and natural gas reserves involves the preparation of estimates that have an inherent degree of associated uncertainty. Categories of proved and probable reserves have been established to reflect the level of these uncertainties and to provide an indication of the probability of recovery. The estimation and classification of reserves requires the application of professional judgment combined with geological and engineering knowledge to assess whether or not specific reserves classification criteria have been satisfied. Knowledge of concepts including uncertainty and risk, probability and statistics, and deterministic and probabilistic estimation methods is required to properly use and apply reserves definitions.

The recovery and reserve estimates of oil, NGL and natural gas reserves provided herein are estimates only. Actual reserves may be greater than or less than the estimates provided herein. The estimated future net revenue from the production of the Corporation’s natural gas and petroleum reserves does not represent the fair market value of the Corporation's reserves.

Caution Respecting BOE

In this AIF, the abbreviation BOE means barrel of oil equivalent on the basis of 1 BOE to 6 Mcf of natural gas when converting natural gas to BOEs. **BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 Mcf to 1 BOE is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.**

Definitions

Certain terms used in this AIF in describing reserves and other oil and natural gas information are defined below. Certain other terms and abbreviations used in this AIF, but not defined or described, are defined in NI 51-101 or the COGE Handbook and, unless the context otherwise requires, shall have the same meanings herein as in NI 51-101 or the COGE Handbook.

Reserves

Reserves are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, from a given date forward, based on: (a) analysis of drilling, geological, geophysical and engineering data; (b) the use of established technology; and (c) 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 as follows:

“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.

The qualitative certainty levels referred to in the definitions above are applicable to "individual reserves 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 estimates 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.

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

"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 (e.g., 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 as follows:

"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 (e.g., 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 classification (proved, probable, possible) 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 sub-divide 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.

Interests in Reserves, Production, Wells and Properties

"gross" means: (a) in relation to an issuer's interest in production or reserves, its "company gross reserves", which are its working interest (operating or non-operating) share before deduction of royalties and without including any royalty interests of the issuer; (b) in relation to wells, the total number of wells in which an issuer has an interest; and (c) in relation to properties, the total area of properties in which an issuer has an interest.

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

"working interest" means the percentage of undivided interest held by an issuer in the oil and/or natural gas or mineral lease granted by the mineral owner, Crown or freehold, which interest gives the issuer the right to "work" the property (lease) to explore for, develop, produce and market the leased substances.

Description of Exploration and Development Wells and Costs

"**development costs**" means costs incurred to obtain access to reserves and to provide facilities for extracting, treating, gathering and storing the crude oil and natural gas from the reserves. More specifically, development costs, including applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to: (a) gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, gas lines and power lines, to the extent necessary in developing the reserves; (b) drill and equip development wells, development type stratigraphic test wells and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment and wellhead assembly; (c) acquire, construct and install production facilities such as flow lines, separators, treaters, heaters, manifolds, measuring devices and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems; and (d) provide improved recovery systems.

"development well" means a well drilled inside the established limits of an oil or gas reservoir, or in close proximity to the edge of the reservoir, to the depth of a stratigraphic horizon known to be productive.

"exploration costs" means costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects that may contain oil and natural gas reserves, including costs of drilling exploratory wells and exploratory type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property (sometimes referred to in part as "prospecting costs") and after acquiring the property. Exploration costs, which include applicable operating costs of support equipment and facilities and other costs of exploration activities, are: (a) costs of topographical, geochemical, geological and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews and others conducting those studies (collectively sometimes referred to as "geological and geophysical costs"); (b) costs of carrying and retaining unproved properties, such as delay rentals, taxes (other than income and capital taxes) on properties, legal costs for title defence, and the maintenance of land and lease records; (c) dry hole contributions and bottom hole contributions; (d) costs of drilling and equipping exploratory wells; and (e) costs of drilling exploratory type stratigraphic test wells.

"**exploration well**" means a well that is not a development well, a service well or a stratigraphic test well.

"**service well**" means a well drilled or completed for the purpose of supporting production in an existing field. Wells in this class are drilled for the following specific purposes: gas injection (natural gas, propane, butane or flue gas), water injection, steam injection, air injection, salt water disposal, water supply for injection, observation or injection for combustion.

SPECIAL NOTE REGARDING FORWARD LOOKING STATEMENTS

Certain statements contained in this Annual Information Form constitute forward-looking statements. The use of any of the words "anticipate", "continue", "estimate", "expect", "may", "will", "project", "should", "believe" and similar expressions are intended to identify forward-looking statements. These 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. The Corporation 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. Since forward-looking statements address future events and conditions, by their very nature they involve inherent risks and uncertainties. Such forward-looking statements included in this Annual Information Form should not be unduly relied upon. These statements speak only as of the date of this Annual Information Form.

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

- the performance characteristics of the Corporation's oil and natural gas properties;
- oil and natural gas production levels;
- the size of the oil and natural gas reserves;
- projections of market prices and costs;
- supply and demand for oil and natural gas;
- expectations regarding the ability to raise capital and to continually add to reserves through acquisitions and development;
- treatment under governmental regulatory regimes and tax laws; and
- capital expenditure programs and the allocation of such capital;

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

- oil and natural gas production levels;
- prevailing weather conditions, commodity prices and exchange rates;
- availability of labour, services and drilling equipment;
- timing and amount of capital expenditures;
- general economic and financial market conditions;
- government regulation in the areas of taxation, royalty rates and environmental protection; and
- the success of exploration and development activities.
- the success, nature and timing of waterflood activities.

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

- volatility in market prices for oil and natural gas;
- volatility in exchange rates;
- liabilities inherent in oil and natural gas operations;
- uncertainties associated with estimating oil and natural gas reserves;
- inability to secure labour, services or equipment on a timely basis or on favourable terms;
- competition for, among other things, capital, acquisitions of reserves, undeveloped lands and skilled personnel;
- unfavourable weather conditions;
- incorrect assessments of the value of acquisitions and exploration and development programs;
- geological, technical, drilling, completion and processing problems;
- results of waterflood responses.
- changes in legislation, including changes in tax laws and incentive programs relating to the oil and gas industry; and
- the other factors discussed under "Risk Factors".

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.

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. The Corporation does not undertake any obligation to publicly update or revise any forward-looking statements other than as required under applicable securities laws.

SURGE ENERGY INC.

General

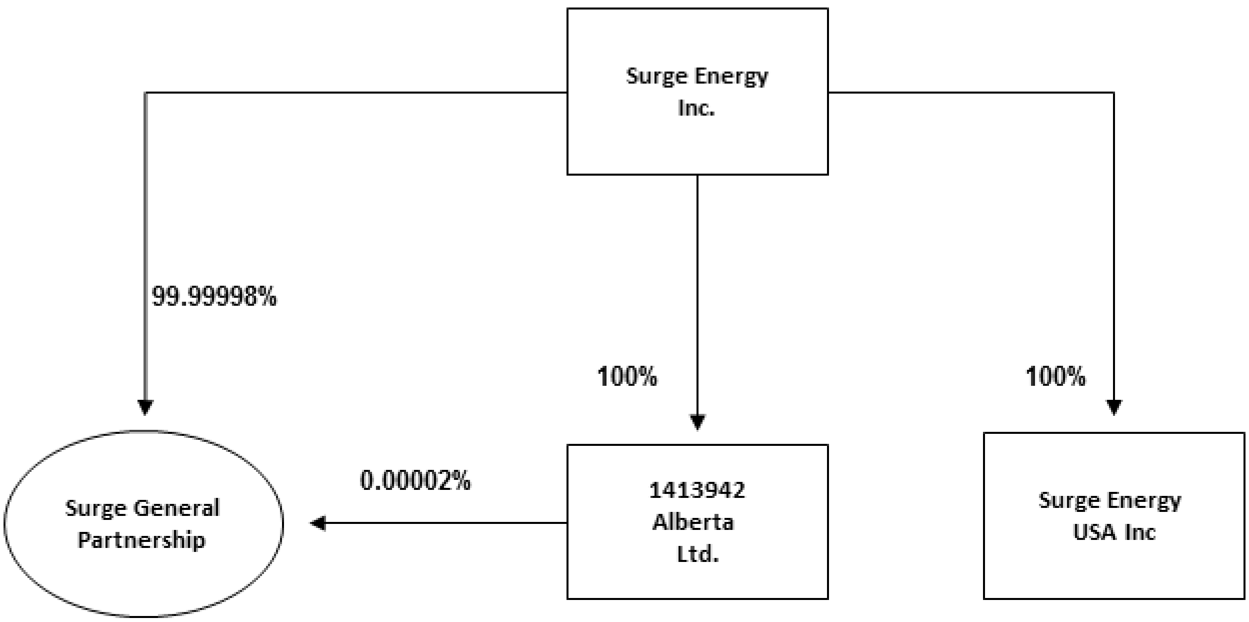
The Corporation is a Calgary, Alberta based, public company whose Common Shares are listed on the TSX under the symbol "SGY". The Corporation was incorporated on January 26, 1998 under the ABCA as "Zapata Capital Inc." and completed its initial public offering of 1,000,000 Common Shares on August 21, 1998 under the Alberta Stock Exchange's junior capital pool program. On June 18, 1999, the Corporation acquired all of the issued and outstanding shares of 744997, a private corporation, as the Corporation's major transaction under the Alberta Stock Exchange's junior capital pool program and amalgamated with 744997 on that date under the name "Zapata Energy Corporation". On June 25, 2010, the Corporation changed its name to "Surge Energy Inc." by way of articles of amendment. On December 31, 2010, the Corporation amalgamated with its wholly owned subsidiary Breaker Resources Ltd. by way of articles of amalgamation and continued under the name "Surge Energy Inc.". On October 21, 2011, the Common Shares commenced trading on the TSX and ceased trading on the TSXV. On December 31, 2012, the Corporation amalgamated with is wholly owned subsidiary Surge Oil Inc. by way of articles of amalgamation and continued under the name "Surge Energy Inc.".

The Corporation is an independent Calgary, Alberta based oil and gas company which acquires interests in petroleum and natural gas rights, that explores for, develops, produces and markets petroleum and natural gas reserves primarily in Western Canada and the Northern United States. The Corporation's strategy for growth is based on positioning the Corporation in early stage oil resource plays that have the following key criteria: significant oil in place per section with low recovery factor to date, significant undeveloped land, available infrastructure, high working interest, operatorship, all-season access and drilling inventory that provides a definable high rate of return. The Corporation plans to utilize its proven expertise and experience to build core areas which can deliver top quartile corporate performance.

Management of the Corporation believes in controlling the timing and costs of its projects wherever possible. Accordingly, the Corporation seeks to become the operator of its properties. Further, to minimize competition within its geographic areas of interest, the Corporation strives to maximize its working interest ownership in its properties.

To achieve sustainable and profitable growth, the Corporation intends to maintain a balance between exploration, exploitation, development drilling for oil and gas reserves, and making asset and corporate acquisitions that meet the Corporation's business parameters.

The Corporation has the following direct and indirect wholly-owned subsidiaries: 1413942 Alberta Ltd. and Surge Energy USA Inc. (North Dakota). The Corporation and 1413942 Alberta Ltd. are the general partners of Surge General Partnership. The corporate structure of the Corporation and its subsidiaries is as set forth in the diagram below:



The head office of the Corporation is located at 2100, 635 – 8th Avenue S.W., Calgary, Alberta T2P 3M3. The registered office of the Corporation is located at 1900, 215 – 9th Avenue S.W., Calgary, Alberta, T2P 1K3.

DEVELOPMENT OF THE BUSINESS

General

The Corporation is an independent Calgary, Alberta based oil and gas company which acquires interests in petroleum and natural gas rights, that explores for, develops, produces and markets petroleum and natural gas reserves primarily in Western Canada and the Northern United States. The Corporation's strategy for growth is based on positioning the Corporation in early stage oil resource plays that have the following key criteria: significant oil in place per section with low recovery factor to date, significant undeveloped land, available infrastructure, high working interest, operatorship and drilling inventory that provides a definable high rate of return. The Corporation plans to utilize its proven expertise and experience to build core areas which can deliver top quartile corporate performance.

Significant developments of the Corporation over the last three completed financial years are as set forth below:

2010

On March 24, 2010, the Corporation entered in the Recapitalization Agreement. On April 13, 2010, the then existing directors and officers of the Corporation resigned and were replaced by the current directors and officers of the Corporation, with the exception of Murray Smith and Colin Davies, who subsequently joined the Board. The Corporation concurrently completed a non-brokered private placement pursuant to which it issued 1,787,500 Common Shares at a price of $4.40 per Common Share, 1,394,317 Units at a price of $4.40 per Unit and 681,819 FT Units at a price of $4.40 per FT Unit, for total proceeds of approximately $17.0 million. Each Unit consists of one Common Share and one Performance Warrant entitling the holder to purchase one Common Share at a price of $5.17 for a period of five years, subject to certain conditions. Each FT Unit consists of one Common Share issued on a "flow-through" basis in accordance with the Tax Act and one Performance Warrant.

All of the Common Shares, Units and FT Units issued pursuant to the non-brokered private placement were subject to a contractual escrow arrangement under which one-third of the securities were released from escrow each six months following the date of issuance. All such escrowed securities have now been released from escrow.

Subsequent to the Recapitalization and concurrent non-brokered private placement, the Corporation changed its name to Surge Energy Inc., completed three equity bought deal financings (details outlined below), completed three private company acquisitions, one asset acquisition, increased its bank line from $50 to $90 million, graduated to the TSX and increased its proved plus probable reserves from 9.9 to 21.2 million BOE.

As mentioned above, the Corporation completed two equity bought deal financings in 2010, subsequent to the Recapitalization. On May 5, 2010, the Corporation completed a short form prospectus offering of 6,945,000 Common Shares at a price of $7.20 per Common Share for aggregate gross proceeds of approximately $50,004,000. In conjunction with the Valhalla Asset Acquisition, the Corporation issued an aggregate of 8,001,000 Subscription Receipts at a price of $5.25 per Subscription Receipt for gross proceeds of $42,005,250.

During 2010, the Corporation drilled a total of 22 gross (21.5 net) wells resulting in 10 development wells in southeast Alberta, three horizontal multi-frac wells at Windfall, five horizontal multi-frac wells at Waskada, two water injectors, and two exploratory wells for an overall success rate of 91 percent.

The Recapitalization

On March 24, 2010, the Corporation entered into the Recapitalization Agreement. The Recapitalization Agreement provided for the transactions described immediately above.

New Management Group

In conjunction with the completion of the non-brokered private placement on April 13, 2010, the then existing directors and officers of the Corporation were replaced by the current directors and officers of the Corporation, with the exception of Murray Smith and Colin Davies, who subsequently joined the Board. The names and principal occupations of each of such directors and officers are set forth in the material change report of the Corporation dated March 29, 2010, which is incorporated by reference in this AIF.

Each member of the Board of Directors, with the exception of P. Daniel O'Neil who is the President and Chief Executive Officer of the Corporation and James Pasieka, who is a partner of Heenan Blaikie LLP, which law firm provides legal services to the Corporation, is independent of the Corporation as defined under National Instrument 58-101 – *Disclosure of Corporate Governance Practices*. The Audit Committee of the Board of Directors is comprised of Keith Macdonald, Murray Smith and Peter Bannister, each of whom is independent of the Corporation as defined under National Instrument 52-110 – *Audit Committees*.

The Recapitalization is described in greater detail in the material change reports of the Corporation dated March 29, 2010 and April 16, 2010.

Subsequent to the Re capitalization, Murray Smith and Colin Davies joined the Board of Directors of the Corporation (on June 25 and July 9, 2010 respectively).

Prospectus Financing

On May 5, 2010, the Corporation completed a short form prospectus offering of 6,945,000 Common Shares at a price of $7.20 per Common Share for aggregate gross proceeds of approximately $50,004,000. The financing was concluded on a bought deal basis with a syndicate of underwriters led by National Bank Financial Inc. and including FirstEnergy Capital Corp., Macquarie Capital Markets Canada Ltd., GMP Securities L.P., CIBC World Markets Inc., Cormark Securities Inc., Peters & Co. Limited and Wellington West Capital Markets Inc. Proceeds of the offering were used for the expansion of the capital program, repayment of debt and general corporate purposes.

Corinthian and Crystal Lake Acquisition

On July 9, 2010, pursuant to the Corinthian Acquisition Agreement, the Corporation completed the Corinthian Acquisition.

The Corinthian Acquisition was approved by the shareholders of Corinthian. Upon completion of the Corinthian Acquisition, one director of Corinthian, Colin Davies joined the Board of Directors of the Corporation. The Corinthian Acquisition Agreement, among other things, provided for a mutual non-completion fee of up to $3.5 million in the event the Corinthian Acquisition was not completed in certain circumstances.

Through the Corinthian Acquisition, the Corporation acquired light oil and natural gas reserves, which included two high impact light oil core areas: one in Alberta and one in southwest Manitoba. The producing properties were greater than 90 percent operated with high working interests, had 3D & 2D seismic coverage, maintained control of key producing infrastructure and were associated with nearly 80,000 acres of net undeveloped land.

In addition to the Corinthian Acquisition, on July 19, 2010 the Corporation also completed an acquisition of a private oil and gas company, Crystal Lake Resources Ltd, for total consideration of 288,639 Common Shares. The assets that were acquired pursuant to the Crystal Lake Acquisition were producing approximately 40 BOE per day at the time of the Crystal Lake Acquisition, are synergistic with the Corporation's southern Alberta assets and provided the Corporation with five unbooked horizontal well locations targeting oil in the Sawtooth Formation.

The Corinthian Acquisition and the Crystal Lake Acquisition are described in greater detail in the material change report of the Corporation dated June 23, 2010. In addition, please see the business acquisition report of the Corporation dated September 22, 2010 for further particulars concerning the Corinthian Acquisition.

Name Change

At a meeting of Shareholders held on June 25, 2010, the Corporation changed its name from Zapata Energy Corporation to Surge Energy Inc. and the Common Shares started trading on the TSXV under the ticker symbol "SGY" on June 30, 2010.

Valhalla Asset Acquisition

On November 1, 2010, the Corporation completed the acquisition of the Valhalla Assets from the Vendor for total consideration of $75 million, subject to adjustments. The Valhalla Assets consisted of a high working interest, operated property producing approximately 726 BOE per day in the Valhalla South area located in western Alberta.

For further particulars regarding the Valhalla Asset Acquisition, see the material change report of the Corporation dated October 1, 2010 and the business acquisition report dated November 10, 2010.

Subscription Receipt Offering

In conjunction with the Valhalla Asset Acquisition, the Corporation completed the Offering, pursuant to which the Corporation issued an aggregate of 8,001,000 Subscription Receipts at a price of $5.25 per Subscription Receipt for gross proceeds of $42,005,250. Pursuant to the Offering, the Subscription Receipts were offered by way of private placement in the provinces of British Columbia, Alberta, Saskatchewan, Manitoba, Ontario and Nova Scotia.

Each Subscription Receipt entitled the holder thereof to receive, for no additional consideration and without further action, one Common Share, upon the earlier to occur of: (i) four months and a day from the closing date of the Offering, and (ii) the date that a receipt was issued for a prospectus qualifying the distribution of the Common Shares underlying the Subscription Receipts. The escrowed funds were released from escrow on November 1, 2010 following the satisfaction of the escrow release conditions pursuant to the Subscription Receipt Agreement. Immediately following the closing of the Valhalla Asset Acquisition, the escrowed funds were used to pay down a portion of the outstanding amount of the Credit Facility that was drawn down to fund the balance of the purchase price for the Valhalla Assets on this date.

On November 22, 2010, a receipt was issued by the securities commissions in all Provinces of Canada, except Québec, qualifying the distribution of the Common Shares underlying the Subscription Receipts and such Common Shares were issued in accordance with the terms of the Subscription Receipts and the Subscription Receipt Agreement.

The Valhalla Asset Acquisition and the Offering are described in greater detail in the material change report of the Corporation dated October 1, 2010 and the business acquisition report dated November 10, 2010.

2011

USA Acquisitions

On March 30, 2011 and May 13, 2011, respectively, the Corporation completed two light oil asset acquisitions in North Dakota through its wholly owned subsidiary, Surge Energy USA Inc. Through the two acquisitions, the Corporation acquired approximately 100 barrels per day (2010 exit rate) of light oil production, 6,000 net acres of highly prospective land in the Spearfish light oil resource play and greater than 100,000 acres of other high working interest, undeveloped land for total consideration of $20.9 million in cash.

Credit Facility

On May 16, 2011, the Corporation confirmed an increase in the Credit Facility from $90 million to $120 million. Subsequently, on September 12, 2011, the Corporation confirmed a further increase to the Credit Facility from $120 million to $150 million.

Prospectus Financing

On October 12, 2011, the Corporation completed a short form prospectus bought deal financing pursuant to which 6,897,000 Common Shares were issued at a price of $8.70 per Common Share for aggregate gross proceeds of approximately $60 million. Net proceeds from the financing were used to temporarily reduce bank indebtedness owing under the Credit Facility, and to use the availability created thereunder to fund ongoing exploration and development activities, potential land and asset acquisitions and general corporate purposes.

TSX Graduation

On October 21, 2011, the Common Shares commenced trading on the facilities of the TSX after the Corporation graduated to the TSX from the TSXV.

2012

Pradera Acquisition

On December 15, 2011, the Corporation entered into an agreement (the "**Pradera Acquisition Agreement**") with Pradera Resources Inc. ("**Pradera**") dated effective December 15, 2011 providing for the acquisition of all of the issued and outstanding shares of Pradera (the "**Pradera Acquisition**").

The completion of the Pradera Acquisition added approximately 1,200 bbls per day (100 percent light oil) of Slave Point/Gilwood light oil assets to the Corporation's portfolio. Total consideration of the acquisition was approximately $106 million, consisting of 7.9 million Common Shares, $18.5 million in cash, and the assumption of net debt totaling $14.5 million.

For further particulars regarding the Pradera Acquisition, see the material change report of the Corporation dated December 15, 2011 and the business acquisition report dated April 12, 2012.

Through the Pradera Acquisition, the Corporation acquired light oil production in its early stage of primary development focused in the Slave Point/Gilwood in the Gift/Nipisi area of Western Alberta, approximately 60 kilometers north-west of Slave Lake, Alberta and consist of approximately 1,200 bbl/d of production (100% light oil).

The Pradera Acquisition was considered to be a "significant acquisition" under applicable securities laws.

Credit Facility

The Credit Facility was increased from $150 million to $175 million in connection with the Pradera Acquisition. On April 12, 2012, the Corporation confirmed a further increase in the Credit Facility from $175 million to $250 million. In December 2012, the Corporation confirmed a further increase in the Credit Facility from $250 million to $290 million.

Other Acquisitions

Excluding the Pradera acquisition, Surge made a number of acquisitions throughout the year in the amount of $9.7 million and disposed of non-core assets for which it received $4.1 million.

DESCRIPTION OF THE BUSINESS

Corporate Strategy

The Corporation's business plan is to build a company that targets per share growth through the early identification, capture, and cost-effective exploitation of high impact oil resource plays. To accomplish this, the Corporation intends to place high priority on positioning the Corporation in early stage oil resource plays that have the following key criteria: significant oil in place per section with a low recovery factor to date, significant undeveloped land, available infrastructure, high working interest, operatorship and that provide a definable high rate of return drilling inventory. The Corporation plans to utilize its proven expertise and experience to build core areas which can deliver top quartile corporate performance.

To achieve sustainable and profitable growth, the Corporation intends to utilize its skills in identifying and capturing oil resource plays and then cost effectively exploiting those reserves. To achieve this, the Corporation may make asset and corporate acquisitions or enter into agreements that meet the Corporation's business parameters.

Management of the Corporation believes in controlling the timing and costs of its projects wherever possible. Accordingly, the Corporation seeks to become the operator of its properties. Further, to minimize competition within its geographic areas of interest, the Corporation strives to maximize its working interest ownership in its properties.

In reviewing potential drilling or acquisition opportunities, the Corporation gives consideration to the following criteria:

(a) risk capital to secure or evaluate the opportunity;

(b) the potential return on the project, if successful;

(c) the likelihood of success; and

(d) risked return versus cost of capital.

In general, the Corporation pursues a portfolio approach in developing a large number of opportunities with a balance of risk profiles in an attempt to generate sustainable high levels of growth. It should be noted that the Board of Directors of the Corporation may, in its discretion, approve asset or corporate acquisitions or investments that do not conform to the guidelines discussed above based upon the Board's consideration of the qualitative aspects of the subject properties, including risk profile, technical upside, reserve life and asset quality.

In addition, the management team of the Corporation, as described below under "*Directors and Officers*", is continually assessing the assets and operations of the Corporation, including its existing land base, facilities, reserves, prospects and personnel. While the Corporation has prepared a budget for 2013 based on guidance for such year, the Corporation may further evaluate its existing reserves, drilling prospects, prevailing commodity prices and capital expenditure program, among other items, and may change its budget as the year progresses.

The Corporation currently plans to pursue the development of its proven and probable undeveloped reserves within the next two years through ordinary course capital expenditures. However, the Corporation may choose to accelerate or delay development depending on a number of circumstances, including the existence of higher priority expenditures and prevailing commodity prices and cash flow.

Competition

The oil and natural gas industry is competitive in all its phases. The Corporation competes with numerous other participants in the search for, and the acquisition of, oil and natural gas properties and in the marketing of oil and natural gas. The Corporation's competitors include resource companies which have greater financial resources, staff and facilities than those of the Corporation. Competitive factors in the distribution and marketing of oil and natural gas include price and methods and reliability of delivery. The Corporation believes that its competitive position is equivalent to that of other oil and gas issuers of similar size and at a similar stage of development.

Seasonal Factors

The exploration for and development of oil and natural gas reserves is dependent on access to areas where production is to be conducted. Seasonal weather variations, including freeze-up and break-up, affect access in certain circumstances.

Environmental Regulation

The oil and natural gas industry is currently subject to environmental regulations pursuant to a variety of provincial and federal legislation. Compliance with such legislation can require significant expenditures or result in operational restrictions. Breach of such requirements may result in suspension or revocation of necessary licenses and authorizations, civil liability for pollution damage and the imposition of material fines and penalties, all of which might have a significant negative impact on earnings and overall competitiveness. See below under the headings "*Industry Conditions - Environmental Regulation*" and "*Risk Factors – Environmental Concerns*".

The Corporation is obligated to abandon, retire and reclaim wells and wellsites in compliance with applicable environmental laws and regulations. As of December 31, 2012, the Corporation has recorded an asset retirement obligation of $39.3 million. The Corporation anticipates that the expenditures necessary to satisfy the asset retirement obligation will be incurred over a period of 50 years, with the majority of the expenditures being incurred from years one to 28. Other than asset retirement obligations and ordinary course operational expenditures necessary to ensure environmental compliance, the Corporation is not aware of any environmental protection requirement that will impact its capital expenditures, earnings or competitive position in a manner disproportionate to that of its peers in its area of operations.

Personnel

As at December 31, 2012, the Corporation had 57 head office employees and three field employees.

PRINCIPAL PRODUCING PROPERTIES

The Corporation's principal oil and natural gas producing properties are located in Alberta, southwest Manitoba and North Dakota. A description of those properties, as at December 31, 2012, is provided below.

Valhalla, Western Alberta

The Valhalla property is located in North Western Alberta, approximately 40 kilometers northwest of Grand Prairie (TWP 74, Range 8, W6M). This operated property consists of an average working interest of approximately 93 percent in approximately 8,640 gross (8,026 net) undeveloped acres as at December 31, 2012. The majority of production from this property was from the new horizontal oil wells producing from an extensive tight sand, with up to 50 meters of gross light oil pay in the Triassic Doig Formation. During 2012, the Corporation increased the internally estimated DPIIP to 140 million barrels (gross) from 115 million barrels (gross) at Valhalla in the Doig light oil pool.

As at December 31, 2012 Surge had drilled a total of 15 gross (11.25 net) horizontal multi-frac wells at Valhalla, of which, seven gross wells (4.3 net) were drilled during 2012. During the latter part of the fourth quarter in 2012, Surge installed additional compression at the 6-18 battery site. The additional compression increased the field compression for solution gas by 40 percent. The additional unit was necessary to reduce field operating pressures and to accommodate the next two years of planned development.

The Corporation continued to add Doig light oil properties through its purchase of an additional 3.75 gross (3.75 net) sections of land at Wembley, one township south of Valhalla. Surge internally estimates 18 million barrels of DPIIP in the Doig Formation at Wembley and has identified potential for an additional six gross (six net) horizontal multi-frac well locations. The Corporation's estimate is based on data from existing vertical wells and a producing horizontal multi-frac oil well adjacent to Surge's new land.

In 2013, Surge announced that it had received objections to holding applications before the ERCB in the southern portion of the pool, which are necessary to further downspace the Doig pool to its optimal development well density**.** This matter will be the subject of an ERCB Hearing scheduled to commence on May 21, 2013. Allegations have been made that Surge is producing their gas from the Halfway formation as a result of cross-flow from the Halfway formation into the Corporation's Doig formation at Valhalla. If the defense against the action were to be unsuccessful, management does not expect the outcome of the action to have a material effect on the Corporation's financial position. The amount of potential damages and legal costs have not been determined due to the complex nature of the claim and calculations required to determine what amount would be owing due to the cross-flow.

The Corporation plans to drill approximately eight gross (5.4 net) horizontal multi-frac wells at Valhalla and one gross (0.44 net) horizontal multi-frac well at Wembley in 2013. At December 31, 2012 the Corporation has identified approximately 46 gross (36.9 net) horizontal multi-frac oil wells at Valhalla/Wembley, with a remaining inventory of 32 gross (25.7 net) drilling locations.

Windfall, Western Alberta

The Corporation's Windfall assets are located in Western Alberta near Whitecourt (TWP 59, Range 15, W5M). At December 31, 2012, this operated property consists of approximately 28,640 gross (28,024 net) undeveloped acres with a working interest of 98 percent. The production from this property was from nine horizontal multi-frac wells and nine vertical wells. Surge internally estimates 60 mmbbls of DPIIP in the Bluesky Formation at Windfall.

As of December 31, 2012, there were nine gross (nine net) horizontal multi-frac wells producing at Windfall. The Corporation did not drill any wells during 2012. During 2012, Surge focused on the implementation of its waterflood project.

The Energy Resources and Conservation Board (ERCB) approved the Corporation's waterflood pilot and injection commenced during the third quarter of 2012. Surge expects to see a waterflood pilot response from the two offsetting horizontal multi-frac producing wells during the second quarter of 2013. Assuming a full field commercial waterflood is viable, Surge estimates that it can ultimately recover at least 25 percent of the estimated 60 million barrels of DPIIP in this pool.

At December 31, 2012, the Corporation identified over 38 gross (38 net) horizontal multi-frac drilling locations at Windfall. The Corporation plans to drill one horizontal multi-frac well at Windfall in 2013 and convert an additional horizontal multi-frac well into an injector during the second quarter of 2013 upon seeing a positive waterflood response from the original injector.

North Dakota

On March 30, 2011 and May 13, 2011, respectively, the Corporation completed two light oil asset acquisitions in North Dakota through its wholly owned subsidiary, Surge Energy USA Inc. Through the two acquisitions, the Corporation acquired approximately 100 barrels per day (2010 exit rate) of light oil production, 6,000 net acres of highly prospective land in the Spearfish light oil resource play and greater than 100,000 acres of other high working interest, undeveloped land for total consideration of $20.9 million in cash.

At December 31, 2012, Surge estimated there to be 126 gross (74 net) million barrels of DPIIP in the Spearfish light oil pool in North Dakota, and approximately 85,292 gross (82,762 net) undeveloped acres with a working interest of 97 percent.

During 2012 Surge participated in the drilling of 20 gross (11 net) horizontal mult-frac wells in North Dakota. The Corporation participated in working interest wells with two different operators and successfully executed a 100 percent working interest and operated single five well pad.

At December 31, 2012, the Corporation has identified 210 gross (109.0 net) horizontal multi-frac drilling locations. During 2013, the Corporation plans to drill three gross (1.26 net) horizontal multi-frac wells and continue to participate in non-operated wells with its working interest partners. In addition, the Corporation also plans to drill two gross (two net) vertical exploration wells to test for Spearfish and Madison Formations and continue to high-grade future Spearfish development areas during 2013.

Nipisi/Gift, Central Alberta

The completion of the Pradera Acquisition on January 6, 2012 added approximately 1,200 bbls per day (100 percent light oil) of Slave Point/Gilwood light oil assets to the Corporation's portfolio. Total consideration of the acquisition was approximately $106 million, consisting of 7.9 million Common Shares, approximately $18.5 million in cash, and the assumption of net debt of approximately $14.5 million. At December 31, 2012, this operated property consisted of approximately 18,240 gross (17,265 net) undeveloped acres with a working interest of 95 percent.

Surge commenced drilling at Nipisi into both the Slave Point and the Gilwood Formations during the first quarter of 2012. A total of nine gross (nine net) horizontal multi-frac wells were drilled into the Slave Point Formation and two gross (two net) wells were drilled into the Gilwood during the year.

During 2012, Surge was successful in increasing its net working interest in the main block at Nipisi from approximately 88 percent to 100 percent through two asset acquisitions. The Corporation also completed an extensive technical review of its lands at Nipisi in the Slave Point Formation which resulted in an increase in its internally estimated DPIIP from 65 million barrels to 85 million barrels of light oil and a significant increase in the identified horizontal multi-frac drilling inventory from 16 gross (16 net) to 44 gross (44 net) drilling locations.

The Corporation continued to add to its land position in the area by purchasing an additional 4.75 sections of land at Nipisi South during the year. Using existing vertical well control as well as historical production profiles, Surge estimates there to be approximately 30 million barrels of gross DPIIIP on its lands at Nipisi South. During 2012, Surge also executed a farm-in on two sections of Slave Point rights and in early 2013 acquired another 1.5 sections at a Crown sale in the Utikuma area, just northwest of Surge's main block at Nipisi. The lands directly offset a vertically developed Slave Point pool where cumulative well production ranges from 10 to over 80 thousand barrels of oil per well. Surge estimates that there are 14 million barrels of DPIIP on these lands.

The Corporation received its waterflood application approval early in the fourth quarter of 2012 and expects injection into the Slave Point Formation to commence in the second quarter of 2013. Based on successful waterflood implementation, Surge estimates that it will ultimately recover at least 20 percent of the estimated 85 million barrels of DPIIP in the main pool.

At December 31, 2012, the Corporation identified 38 gross (38 net) horizontal multi-frac drilling locations in the Slave Point Formation and 11 gross (7.9 net) drilling locations in the Gilwood. The Corporation plans to drill four gross (four net) horizontal multi-frac Slave Point wells in the main block at Nipisi and one gross (0.75 net) horizontal well at Nipisi South and one gross (0.70 net) horizontal multi-frac earning well at Utikuma during 2013.

Waskada, Pierson and Goodlands Southwest Manitoba

In southwest Manitoba, the Corporation has accumulated a land position at Waskada, Pierson and Goodlands, providing it with access to the Spearfish (Amaranth) light oil resource play.

At December 31, 2012, the Corporation had approximately 8,689 gross (8,689 net) undeveloped acres of land in Waskada with an average working interest of 100 percent. The Corporation has identified approximately 124 gross (111 net) horizontal multi-frac drilling locations at Waskada. Additionally, the Corporation has 1,228 gross (1,228 net) undeveloped acres of land in Pierson and Goodlands with an average working interest of 100 percent.

As of December 31, 2012, the Waskada field was producing from 21 horizontal multi frac wells. Of the 21 wells, four gross (4 net) wells were drilled in 2012.

Surge continued to make progress on the Waskada Unit 15 waterflood pilot during 2012. A third party waterflood study was completed during 2012 and the results were encouraging. The results from the report prompted Surge to plan construction of the infrastructure in January 2013 with the first phase of water injection commencing in the first quarter of 2013 with the conversion of existing horizontal producing wells to injection wells. Surge expects to see a waterflood response within six months of injection. Surge estimates that under a full field waterflood development, this pool has the potential to recover approximately 20 percent of the estimated DPIIP of 10 million barrels per section.

Silver Lake Area, South East Alberta

In South East Alberta, the Corporation held approximately 126,820 gross (121,377 net) acres of undeveloped land at December 31, 2012 with an average working interest of approximately 96 percent. The Corporation has interests in 185 gross (172 net) oil wells and 98 gross (86 net) gas wells producing from the Lloydminster, Cummings, Rex, Sparky, Dina and Viking Formations. In addition, the Corporation operates six oil batteries and an oil blending facility, providing a strong infrastructure base for future development in the area. The Corporation continues to add to its land base through acquisitions and farmin agreements in the area.

During 2012, the corporation drilled 20 gross (19.75 net) wells in South East Alberta. The Corporation also focused on optimizing its existing waterflood initiatives, adding to its land position and increasing the internally estimated DPIIP in the area. Details are outlined below.

Silver Lake

During 2012, the Corporation added 78 gross (78 net) horizontal drilling locations to its inventory in the Silver Lake Area based on encouraging well results.

The Company also initiated a waterflood facility expansion at Silver Lake which included two new water injection wells, one well conversion and a facility expansion to handle an additional 12,000 barrels of water per day. Post expansion, the field has seen a positive result with recent production increasing by 20 percent to approximately 1,300 boe per day.

Provost

During 2012, Surge established a new Cretaceous oil pool on approximately five sections of land, which the Company estimates to contain DPIIP of 28 million barrels of 29 degree API oil. During the fourth quarter of 2012, Surge completed two (100 percent working interest) horizontal multi-frac wells within this pool. The wells have been performing to type curve expectations of 125 barrels of oil per day with anticipated recovery of 110 thousand barrels of oil per well at a cost of $1.7 million per well.

In 2013, Surge will drill four development wells, one vertical well, one disposal/water source well and upgrade its existing facilities. Surge expects to develop the property on a primary basis with up to 14 wells on 400 meter inter-well spacing. A horizontal well waterflood pilot will likely be initiated in 2014. Numerous analogous waterflood projects exist in similar pools in the area and have demonstrated recovery factors between 20 and 30 percent of DPIIP.

Sounding Lake

At Sounding Lake, a Cretaceous oil pool was established with the drilling of three horizontal wells in the fourth quarter of 2012. The pool is estimated to contain DPIIP of five million barrels of 31 degree API oil. During 2013, Surge plans to drill a total of four wells on this property. The best month average production rate is estimated to be 100 barrels of oil per day with anticipated recovery of 60 thousand barrels of oil at a cost $1.25 million per well.

Sounding Lake East

At Sounding Lake East, Surge has acquired and farmed in on 3.75 sections of land that contain a new Cretaceous oil pool with estimated DPIIP of 47 million barrels of 29 degree API oil. The lands are offset directly by vertical well production and contain bypassed pay in numerous wellbores that provide extensive control for the mapping. The pool is analogous to the Provost pool.

Surge plans to drill a horizontal multi-frac earning well in the first quarter of 2013. The type curve expectation is marginally reduced from that at Provost, with estimated best month average production rates of 100 barrels of oil per day and risked expected recovery of 100 thousand barrels of oil. The primary development of the pool is estimated to require up to 22 wells on 400 meter inter-well spacing. Waterflood implementation is expected after successful primary well development is confirmed. Based on numerous successful offsetting waterfloods in the area, incremental recovery of 20 and 30 percent is expected.

STATEMENT OF RESERVES DATA

In accordance with NI 51-101 – *Standards for Disclosure for Oil and Gas Activities*, Sproule Associates Limited prepared the Sproule Report. The Sproule Report evaluated, as at December 31, 2012, the oil, NGL and natural gas reserves attributable to the properties of the Corporation. The Sproule Report is dated February 5, 2013.

The tables below are a summary of the oil, NGL and natural gas reserves attributable to the properties of the Corporation and the net present value of future net revenue attributable to such reserves as evaluated in the Sproule Report based on forecast price and cost assumptions. The tables summarize the data contained in the Sproule Report and, as a result, may contain slightly different numbers than such report due to rounding. Also due to rounding, certain columns may not add exactly.

The net present value of future net revenue attributable to reserves is stated without provision for interest costs and general and administrative costs, but after providing for estimated royalties, production costs, development costs, other income, future capital expenditures and well abandonment costs for only those wells assigned reserves by Sproule. It should not be assumed that the undiscounted or discounted net present value of future net revenue attributable to reserves estimated by Sproule represent the fair market value of those reserves. Other assumptions and qualifications relating to costs, prices for future production and other matters are summarized herein. The recovery and reserve estimates of oil, NGL and natural gas reserves provided herein are estimates only. Actual reserves may be greater than or less than the estimates provided herein.

The Sproule Report is based on certain factual data supplied by the Corporation and Sproule's opinion of reasonable practice in the industry. The extent and character of ownership and all factual data pertaining to petroleum properties and contracts (except for certain information residing in the public domain) were supplied by the Corporation to Sproule. Sproule accepted this data as presented and neither title searches nor field inspections were conducted.

Summary of Oil and Gas Reserves – Forecast Prices and Costs

	Gross Reserves				Net Reserves			
	Light and Medium Crude Oil (Mbbls)	Heavy Crude Oil (Mbbls)	Natural Gas Liquids (Mbbls)	Natural Gas (MMcf)	Light and Medium Crude Oil (Mbbls)	Heavy Crude Oil (Mbbls)	Natural Gas Liquids (Mbbls)	Natural Gas (MMcf)
Proved								
Developed Producing	6,736.4	3,340.6	877.9	31,648.0	5,351.4	2,738.6	594.3	28,189.0
Developed Non-Producing	725.1	-	72.8	3,326.0	595.6	-	48.0	2,961.0
Undeveloped	4,505.7	1,654.4	773.0	21,736.0	3,646.7	1,361.7	557.5	18,086.0
Total Proved	11,967.2	4,995.0	1,723.7	56,710.0	9,593.7	4,100.3	1,199.8	49,236.0
Probable	10,634.6	1,829.2	766.5	28,540.0	7,755.7	1,489.0	524.9	25,163.0
Total Proved plus Probable	22,601.8	6,824.2	2,490.2	85,250.0	17,349.5	5,589.3	1,724.7	74,399.0

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

	Before Future Income Tax Expenses and Discounted at				
($M)	0%	5%	10%	15%	20%
Proved					
Developed Producing	587,364	445,239	366,062	314,886	278,763
Developed Non-Producing	41,414	31,345	24,514	19,705	16,205
Undeveloped	271,590	183,800	132,908	99,875	76,757
Total Proved	900,368	660,384	523,484	434,466	371,725
Probable	734,192	351,416	208,186	137,352	95,971
Total Proved plus Probable	1,634,560	1,011,800	731,670	571,818	467,695

	After Future Income Tax Expenses and Discounted at				
($M)	0%	5%	10%	15%	20%
Proved					
Developed Producing	560,685	430,147	355,705	306,861	272,056
Developed Non-Producing	30,953	24,708	20,199	16,836	14,259
Undeveloped	200,971	134,667	96,125	71,019	53,374
Total Proved	792,609	589,522	472,029	394,716	339,689
Probable	544,506	257,204	149,360	95,830	64,469
Total Proved plus Probable	1,337,115	846,725	621,389	490,546	404,158

	Unit Value before Income Tax Discounted at 10%/year ($/BOE)
Proved	
Developed Producing	27.35
Developed Non-Producing	21.56
Undeveloped	15.49
Total Proved	22.66
Probable	14.91
Total Proved plus Probable	19.74

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

(Undiscounted) ($M)	Revenue	Royalties	Operating Costs	Development Costs	Abandonment and Other costs	Future net revenue before income taxes	Future income taxes	Future net revenue after income taxes
Total Proved	1,964,105	363,990	533,752	151,731	14,263	900,369	107,759	792,610
Total Proved plus Probable	3,556,605	755,435	892,076	256,900	17,632	1,634,561	297,446	1,337,115

Future Net Revenue by Production Group – Forecast Prices and Costs

	Future Net Revenue Before Income Taxes and Discounted at 10% ($M)	Per Unit Future Net Revenue Before Income Taxes and Discounted at 10%(3) ($BOE)
Proved		
Light and Medium Crude Oil (1)	376,099	21.59
Heavy Oil	137,543	31.73
Natural Gas (2)	9,841	1.22
Proved plus Probable		
Light and Medium Crude Oil (1)	536,538	18.45
Heavy Oil	180,801	30.59
Natural Gas (2)	14,331	1.15

Notes:

(1) Including solution gas and other by-products.
(2) Including by-products, but excluding solution gas from oil wells.
(3) Based on net reserves volumes.

Pricing Assumptions – Forecast Prices and Costs

Sproule employed the following pricing, exchange rate and inflation rate assumptions as of December 31, 2012 in the Sproule Report in estimating reserves data using forecast prices and costs. The weighted average historical prices received by the Corporation for 2012 are also reflected in the table below.

	Medium and Light Crude Oil			Natural Gas	NGL			
Year	WTI Cushing Oklahoma 40˚ API (US$/bbl)	Edmonton Par Price 40˚ API ($/bbl)	Cromer Medium 29.3˚ API ($/bbl)	AECO Gas Price ($/MMBtu)	Pentanes plus FOB Field Gate ($/bbl)	Butanes FOB Field Gate ($/bbl)	Inflation rates (%/Yr)	Exchange rate ($US/$Cdn)
2012 (Surge Actual)	94.19	86.53	80.95	2.43	100.76	64.48	1.3	1.001
2013	89.63	84.55	77.79	3.31	90.53	63.02	1.5	1.001
2014	89.93	89.84	82.66	3.72	96.19	66.96	1.5	1.001
2015	88.29	88.21	81.15	3.91	94.44	65.74	1.5	1.001
2016	95.52	95.43	88.75	4.70	102.18	71.13	1.5	1.001
2017	96.96	96.87	90.09	5.32	103.71	72.20	1.5	1.001
2018	98.41	98.32	91.44	5.40	105.27	73.28	1.5	1.001
2019	99.89	99.79	92.81	5.49	106.85	74.38	1.5	1.001
2020	101.38	101.29	94.20	5.58	108.45	75.50	1.5	1.001
2021	102.91	102.81	95.61	5.67	110.08	76.63	1.5	1.001
2022	104.45	104.35	97.05	5.76	111.73	77.78	1.5	1.001
2023	106.02	105.92	98.50	5.85	113.40	78.95	1.5	1.001

Reconciliation of Changes in Reserves

The following table sets forth a reconciliation of the Corporation's gross reserves as at December 31, 2012, derived from the Sproule Report using forecast prices and cost estimates, reconciled to the gross reserves of the Corporation as at December 31, 2011. The additional reserves associated with royalty interest reserves, representing 5,037.7 MBOE and 9,061.4 MBOE on a proved and proved plus probable basis, respectively, are not included in the following tables.

	Light and Medium Crude Oil (Mbbls)	Heavy Oil (Mbbls)	Natural Gas Liquids (Mbbls)	Natural Gas (MMcf)	BOE (MBOE)
Proved					
Balance at December 31, 2011	8,174.1	2,786.8	1,473.3	48,530.0	20,522.5
Extensions and Improved Recovery	4,377.0	1,229.0	543.3	15,210.0	8,684.2
Technical Revisions	(1,720.8)	1,564.4	(94.1)	368.0	(189.2)
Acquisitions	2,913.0	278.3	-	-	3,191.3
Dispositions	-	(87.0)	-	(16.0)	(89.7)
Economic Factors	(307.1)	(128.2)	(44.2)	(1,455.0)	(722.1)
Production	(1,469.0)	(648.3)	(154.6)	(5,926.0)	(3,259.5)
Balance at December 31, 2012	11,967.2	4,995.0	1,723.7	56,711.0	28,137.5

	Light and Medium Crude Oil (Mbbls)	Heavy Oil (Mbbls)	Natural Gas Liquids (Mbbls)	Natural Gas (MMcf)	BOE (MBOE)
Probable					
Balance at December 31, 2011	4,847.3	1,008.1	904.4	29,548.0	11,684.5
Extensions and Improved Recovery	7,152.1	596.1	260.5	7,646.0	9,283.2
Technical Revisions	(3,179.8)	(157.4)	(438.2)	(9,952.0)	(5,434.3)
Acquisitions	1,548.0	384.3	-	-	1,932.3
Dispositions	-	(118.0)	-	(5.0)	(118.8)
Economic Factors	267.0	116.1	39.8	1,304.0	640.2
Production	-	-	-	-	-
Balance at December 31, 2012	10,634.6	1,829.2	766.5	28,541.0	17,987.1

	Light and Medium Crude Oil (Mbbls)	Heavy Oil (Mbbls)	Natural Gas Liquids (Mbbls)	Natural Gas (MMcf)	BOE (MBOE)
Proved plus Probable					
Balance at December 31, 2010	13,021.4	3,794.9	2,377.7	78,078.0	32,207.0
Extensions and Improved Recovery	11,529.1	1,825.1	803.8	22,856.0	17,967.4
Technical Revisions	(4,900.6)	1,407.0	(532.3)	(9,585.0)	(5,623.4)
Acquisitions	4,461.0	662.6	-	-	5,123.6
Dispositions	-	(205.0)	-	(21.0)	(208.5)
Economic Factors	(40.1)	(12.1)	(4.4)	(152.0)	(81.9)
Production	(1,469.0)	(648.3)	(154.6)	(5,926.0)	(3,259.5)
Balance at December 31, 2011	22,601.8	6,824.2	2,490.2	85,250.0	46,124.7

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:

Proved	Light and Medium Crude Oil (Mbbls)	Heavy Oil (Mbbls)	Natural Gas Liquids (Mbbls)	Natural Gas (MMcf)
Prior to 2010	697.0	339.6	39.0	4,145.9
2010	1,201.5	84.6	263.3	6,839.0
2011	3,343.7	302.3	721.5	19,281.0
2012	2,955.3	1,191.3	306.6	8,393.0

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:

Probable	Light and Medium Crude Oil (Mbbls)	Heavy Oil (Mbbls)	Natural Gas Liquids (Mbbls)	Natural Gas (MMcf)
Prior to 2010	1,220.5	285.4	175.3	9,668.3
2010	1,023.9	236.4	136.2	3,932.0
2011	2,269.7	161.2	398.0	11,128.0
2012	6,703.2	457.2	197.8	5,731.0

Proved undeveloped reserves are generally those reserves related to infill wells that have not yet been drilled or wells further away from gathering systems requiring relatively high capital to bring on production. Probable undeveloped reserves are generally those reserves tested or indicated by analogy to be productive, infill drilling locations and lands contiguous to production. This also includes the probable undeveloped wedge from the proved undeveloped locations.

The Corporation currently plans to pursue the development of its proven and probable undeveloped reserves within the next two years through ordinary course capital expenditures. However, the Corporation may choose to delay development depending on a number of circumstances, including the existence of higher priority expenditures and prevailing commodity prices and cash flow.

Significant Factors or Uncertainties Affecting Reserves Data

The process of estimating reserves is complex. It requires significant judgments and decisions based on available geological, geophysical, engineering, and economic data. These estimates may change substantially as additional data from ongoing development activities and production performance becomes available and as economic conditions impacting oil and gas prices and costs change. The reserve estimates contained herein are based on current production forecasts, prices and economic conditions.

As circumstances change and additional data becomes available, reserve estimates also change. Estimates made are reviewed and revised, either upward or downward, as warranted by the new information. Revisions are often required due to changes in well performance, prices, economic conditions and governmental restrictions.

Although every reasonable effort is made to ensure that reserve estimates are accurate, reserve estimation is an inferential science. As a result, subjective decisions, new geological or production information and a changing environment may impact these estimates. Revisions to reserve estimates can arise from changes in year-end oil and gas prices and reservoir performance. Such revisions can be either positive or negative.

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).

	Forecast Prices and Costs	
	Proved Reserves ($M)	Proved plus Probable Reserves ($M)
2013	85,426	132,607
2014	65,156	115,275
2015	1,149	8,907
2016	-	52
Remaining Years	-	59
Total Undiscounted	151,731	256,900

The Corporation has four sources of funding available to finance its capital expenditure programs: internally generated cash flow from operations, funds raised from the sale of non-core assets, debt financing when appropriate and new issues of Common Shares, if available on favourable terms. The Corporation expects to fund the above future development costs primarily through internally generated cash flow, funds raised from the sale of non-core assets and debt. There can be no guarantee that the Board of Directors will allocate funding to develop all of the reserves attributed in the Sproule Report. Failure to develop those reserves could have a negative impact on the Corporation's future cash flow.

OTHER OIL AND GAS INFORMATION

Oil and Gas Wells

The following table sets forth the number and status of the Corporation's wells effective December 31, 2012.

	Producing Wells				Non-Producing Wells			
	Oil		Natural Gas		Oil		Natural Gas	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Alberta	300	256.99	142	108.59	222	182.21	153	113.05
Manitoba	23	23.00	0	0.00	11	11.00	0	0.00
British Columbia	0	0.00	0	0.00	0	0.00	1	0.54
North Dakota	37	21.17	0	0.00	11	4.17	0	0.00
Total	360	301.16	142	108.59	244	197.38	154	113.59

Properties with no Attributed Reserves

The following table summarizes, effective December 31, 2012, the gross and net acres of unproved properties in which the Corporation has an interest and also the number of net acres for which the Corporation's rights to explore, develop or exploit will, absent further action, expire within one year.

	Gross Acres	Net Acres	Net Acres Expiring within One Year
Alberta	411,768	392,206	61,806
Manitoba	9,917	9,917	1,655
North Dakota	84,069	81,539	10,460
Total	505,754	483,662	73,921

Additional Information Concerning Abandonment and Reclamation Costs

The Corporation typically estimates well abandonment costs area by area. Such costs are included in the Sproule Report as deductions in arriving at future net revenue. The expected total abandonment costs, net of estimated salvage value, included in the Sproule Report for 305.3 net wells under the proved reserves category is $14.3 million undiscounted ($4.1 million discounted at 10%), of which a total of $0.7 million is estimated to be incurred in 2013, 2014 and 2015. This estimate does not include expected reclamation costs for surface leases. The Corporation will be liable for its share of ongoing environmental obligations and for the ultimate reclamation of the properties held by it upon abandonment. Ongoing environmental obligations are expected to be funded out of cash flow.

Tax Horizon

Based on planned capital expenditures and the forecast commodity pricing employed in the Sproule Report, the Corporation estimates that it will not be required to pay current income taxes before 2015.

Costs Incurred

The following table summarizes capital expenditures incurred by the Corporation during the year ended December 31, 2012.

	Property Acquisition Costs				
	Proved Properties	Unproved Properties	Property Dispositions	Exploration Costs	Development Costs
Total ($M)	24,969	2,878	(4,016)	25,604	156,454

Drilling Activity

The following table sets forth the gross and net exploration and development wells drilled by the Corporation based on rig release date during the year ended December 31, 2012.

	Exploration Wells		Development Wells	
	Gross	Net	Gross	Net
Light and Medium Oil	-	-	59.00	47.05
Natural Gas	-	-	-	-
Service	-	-	2.00	2.00
Dry	-	-	1.00	1.00
Total	-	-	62.00	50.05

Planned Capital Expenditures

The Corporation has announced a planned capital expenditure budget of approximately $140 million for 2013. Surge has allocated approximately $124 million to its 2013 drilling program, $9 million to waterflood implementation and optimization, $17 million to a combination of land, acquisitions, corporate and capitalized G&A expenditures and is planning $10 million of non-core dispositions late in the year. The Corporation is planning to drill 32 gross (27.07 net) wells in 2013 targeting high quality light and medium gravity oil, with the majority of the activity at Valhalla (8 gross, 5.38 net wells), Silver Lake (11 gross, 11 net wells), Nipisi/Nipisi South (5 gross, 4.73 net wells) and North Dakota (5 gross, 3.26 net).

Production Estimates

The following table discloses for each product type the total volume of production estimated by Sproule in the Sproule Report for 2013 in the estimates of future net revenue from gross proved and gross proved plus probable reserves disclosed above.

	Light and Medium Oil (bbls/d)	Natural Gas (Mcf/d)	Natural Gas Liquids (bbls/d)	BOE (BOE/d)	%
Proved					
SE Alberta	2,551	854	25	2,718	22%
Valhalla	2,322	19,256	696	6,227	50%
Williston Basin	908	0	0	908	7%
Nipisi	1,436	0	0	1,436	12%
Other	397	3,803	35	1,066	9%
Total Proved	7,614	23,913	756	12,355	100%
Proved Plus Probable					
SE Alberta	2,777	913	26	2,955	22%
Valhalla	2,430	20,402	742	6,572	48%
Williston Basin	994	0	0	994	7%
Nipisi	1,583	0	0	1,583	12%
Other	597	5,423	61	1,562	11%
Total Proved Plus Probable	8,381	26,738	829	13,666	100%

Production History

The following table discloses, on a quarterly basis for the year ended December 31, 2012, certain information in respect of production, product prices received, royalties paid, operating expenses and resulting netback for the Corporation.

Average Daily Production Volume

	Three Months Ended			
	Mar 31, 2012	Jun 30, 2012	Sep 30, 2012	Dec 31, 2012
Natural Gas (Mcf/d)	17,398	16,246	15,846	15,129
Light and Medium Crude Oil (bbls/d)	5,684	6,187	5,219	5,953
NGL (bbls/d)	426	380	433	445
Total (BOE/d)	9,009	9,275	8,292	8,919

Prices Received, Royalties Paid, Production Costs and Netback- Crude Oil

	Three Months Ended			
($ per Bbl)	Mar 31, 2012	Jun 30, 2012	Sep 30, 2012	Dec 31, 2012
Prices Received	65.05	59.93	58.72	61.95
Royalties Paid	(12.90)	(10.11)	(10.58)	(11.81)
Transportation Costs	(1.74)	(2.61)	(0.88)	(3.62)
Production Costs	(11.10)	(10.45)	(12.26)	(11.58)
Netback (1)	39.30	36.76	35.01	34.94

Prices Received, Royalties Paid, Production Costs and Netback- Natural Gas

	Three Months Ended			
($ per Mcf)	Mar 31, 2012	Jun 30, 2012	Sep 30, 2012	Dec 31, 2012
Prices Received	3.91	4.07	4.29	4.04
Royalties Paid	(0.49)	(0.34)	(0.50)	(0.04)
Transportation Costs	(0.38)	(0.37)	(0.46)	(0.40)
Production Costs	(3.21)	(2.31)	(2.86)	(2.25)
Netback (1)	(0.17)	1.05	0.47	1.35

Prices Received, Royalties Paid, Production Costs and Netback- Combined

	Three Months Ended			
($ per Boe)	Mar 31, 2012	Jun 30, 2012	Sep 30, 2012	Dec 31, 2012
Prices Received	62.28	57.97	56.70	60.24
Royalties Paid	(12.22)	(9.69)	(9.96)	(11.36)
Transportation Costs	(1.78)	(2.59)	(2.07)	(2.56)
Production Costs	(11.66)	(10.63)	(11.48)	(12.68)
Netback (1)	36.62	35.06	33.19	33.64

Note:

(1) Netback is calculated by deducting royalties paid and production costs, including transportation costs, from prices received, excluding the effects of hedging.

Production Volume by Field

The following table indicates the average daily net production from the Corporation's important fields for the year ended December 31, 2012.

Field	Light and Medium Oil & NGLs (bbls/d)	Natural Gas (Mcf/d)	Natural Gas Liquids (bbls/d)	BOE (BOE/d)	%
Valhalla	1,330	9,828	353	3,321	37%
SE Alberta	1,760	1,021	23	1,953	22%
Nipisi	1,458	(78)	0	1,445	16%
Williston Basin	813	0	0	813	9%
Other	399	5,380	45	1,341	15%
Total	5,760	16,151	421	8,873	100%

SHARE CAPITAL

The Corporation is authorized to issue an unlimited number of Common Shares and an unlimited number of Preferred Shares issuable in series. As at March 19, 2013, there were 71.2 million Common Shares and no Preferred Shares issued and outstanding.

Common Shares

The holders of Common Shares are entitled to: (i) one vote for each Common Share held at all meetings of shareholders of the Corporation other than meetings of the holders of any class or series of shares meeting as a class or series; (ii) receive any dividends declared by the Corporation on the Common Shares; and (iii) subject to the rights of shares ranking prior to the Common Shares, to receive the remaining property of the Corporation on dissolution, after the payment of all liabilities.

Preferred Shares

Preferred Shares may be issued in one or more series. The Board of Directors is authorized to fix the number of shares in each series and to determine the designation, rights, privileges, restrictions and conditions attached to the shares of each series. Preferred Shares are entitled to a priority over the Common Shares with respect to the payment of dividends and the distribution of assets upon the liquidation, dissolution or winding-up of The Corporation.

DIVIDEND POLICY

The Corporation has not declared or paid any dividends on the Common Shares since its incorporation. Any decision to pay dividends on the Common Shares will be made by the Board of Directors on the basis of the Corporation's earnings, financial requirements and other conditions existing at such future time.

ESCROWED SECURITIES

None of the securities of the Corporation are subject to escrow.

MARKET FOR SECURITIES

The Common Shares are listed and posted for trading on the TSX under the trading symbol "SGY" and have traded on such stock exchange since October 21, 2011. The Common Shares previously traded on the TSXV under the same symbol. The following table sets forth the reported market price ranges and the trading volumes for the Common Shares for the periods indicated, as reported by the TSX for the year ended December 31, 2012.

	Price Range ($)		
Period	**High**	**Low**	**Trading Volume**
2012			
January	9.71	8.75	7,499,713
February	10.37	9.57	9,408,268
March	11.15	9.73	10,463,737
April	10.09	8.39	9,229,170
May	9.37	6.98	6,729,058
June	8.40	6.31	4,944,269
July	7.75	6.47	7,755,927
August	8.24	6.97	6,481,328
September	8.49	7.61	9,213,774
October	7.65	6.53	4,787,423
November	7.11	5.41	15,806,567
December	5.81	5.39	16,198,801

DIRECTORS AND OFFICERS

The name, municipality of residence, principal occupation for the prior five years and position with the Corporation of each of the directors and officers of the Corporation are as follows:

Name and Residence	Position	Principal Occupation During Previous Five Years
P. Daniel O'Neil Calgary, Alberta	Director, President and Chief Executive Officer	Director, President and Chief Executive Officer of the Corporation. Prior thereto, President and Chief Executive Officer of Breaker Energy Ltd., a publicly traded oil and natural gas company, from its formation in September 2004 until its acquisition by NAL Oil & Gas Trust in December 2009. Mr. O'Neil is also a director of both Hyperion Exploration Corp. and Cathedral Energy Services.
Paul Colborne[(4)] Calgary, Alberta	Chairman of the Board of Directors	President of StarValley Oil & Gas Ltd., a private oil and natural gas company, since October 2006, Chairman of Legacy Oil and Gas Inc. and serves on the board of directors of Crescent Point Energy Corp. and Cequence Energy Ltd. Prior thereto, Mr. Colborne served as a director of Wildstream Exploration Inc. prior to its sale in 2012, Chairman of TriStar Oil & Gas Ltd. until its sale in 2009 and a director of Breaker Energy Ltd. until its sale in 2009. Prior thereto, Mr. Colborne was President and Chief Executive Officer of StarPoint Energy Trust, a publicly traded oil and natural gas income trust, until its merger to form Canetic Resources Trust in January 2006 and was Chairman of Seaview Energy Ltd, and was a director of Westfire Energy Ltd. and Twin Butte Energy Ltd.
Robert Leach [(2)] Calgary, Alberta	Director	President and Chief Executive Officer of Custom Truck Sales Ltd., a private company operating Kenworth truck dealerships in Saskatchewan and Manitoba, and President of International Fitness Holdings, an operating arm of a private equity firm operating 25 health clubs in Alberta. Mr. Leach was formerly the Chairman of the Board of Breaker Energy Inc.
Peter Bannister[(1) (3)] Calgary, Alberta	Director	President of Destiny Energy Inc., a privately owned oil and gas company, Chairman of Crescent Point Energy Corp., and also serves on the board of directors of Cequence Energy Ltd. Prior thereto, Mr. Bannister served as a director of Breaker Energy Ltd. until its sale in 2009. He was Vice-President Exploration of Mission Oil and Gas Inc. until its sale in 2006 and Vice-President Exploration of StarPoint Energy Inc., President of Impact Energy Inc. and Vice-President of Corporate Development of Startech Energy Ltd. prior to their respective corporate sales.
Keith Macdonald[(1)(3)(4)] Calgary, Alberta	Director	President of Bamako Investment Management Ltd., a private holding and financial consulting company. Mr. Macdonald is also a director of Bellatrix Exploration Ltd. and Rocky Mountain Dealerships Inc., which are listed on the TSX. As well, he is a director of Madalena Ventures Inc. and Mountainview Energy Ltd., which are listed on the TSX Venture Exchange, and other public and private oil and gas companies.
James Pasieka[(2)] Calgary, Alberta	Director	Partner of the national law firm Heenan Blaikie LLP since 2001. Mr. Pasieka has served as an officer and director of a number of public energy companies, chairman of the board of several oil and gas companies and was formerly Corporate Secretary of Breaker Energy Ltd.

Name and Residence	Position	Principal Occupation During Previous Five Years
Murray Smith[(1) (2)] Calgary, Alberta	Director	Mr. Smith is the president of a private consulting company, Murray Smith and Associates and a director of CriticalControl Business Solutions Corp. and Williams Companies Inc. Mr. Smith also serves on the board of four private companies. Prior thereto, Mr. Smith was an Official Representative of the Province of Alberta to the United States of America until 2007. Prior thereto, he was a member of the Legislative Assembly in the Province of Alberta serving in four different Cabinet portfolios – Energy, Gaming, Labour, and Economic Development from 1993 to 2005.
Colin Davies[(3) (4)] Calgary, Alberta	Director	Mr. Davies is President & CEO and Director of Corinthian Exploration Corp., a private company with oil and gas assets located in Alberta and North Dakota. Prior thereto, Mr. Davies was President & CEO and Director of Corinthian Energy Corp., a private oil and gas company that was founded in 2004 and amalgamated with Surge Energy Inc. in July 2010.
Maxwell Lof Calgary, Alberta	Chief Financial Officer	Chief Financial Officer of the Corporation. Prior thereto, Chief Financial Officer and Vice-President, Finance of Breaker Energy Ltd. from its formation in September 2004 until its acquisition by NAL Oil & Gas Trust in December 2009.
Dan Brown Calgary, Alberta	Chief Operating Officer	Chief Operating Officer of the Corporation. Prior thereto, Chief Operating Officer of Breaker Energy Ltd. from August 2009 until its acquisition by NAL Oil & Gas Trust in December 2009. Prior thereto, Mr. Brown was the Business Unit Team Lead at a major North American production company.
Margaret Elekes Calgary, Alberta	Vice-President, Land	Vice-President, Land of the Corporation. Prior thereto, Consulting Landman for Breaker Energy from its formation in September 2004 until its acquisition by NAL Oil & Gas Trust in December 2009 and Consulting Landman with Legacy Oil + Gas Inc. from December 2009 to March 2010.
Malcolm Adams Calgary, Alberta	Vice-President, Corporate Development	Vice-President, Corporate Development of the Corporation. Prior thereto, Mr. Adams was the Vice-President of ARC Financial Corp. from October 2001 to April 2010. Mr. Adams is also a director of Rock Energy Inc..
Tee Ong Calgary, Alberta	Vice-President, Engineering	Vice-President, Engineering of the Corporation. Prior thereto, Mr. Ong has held engineering positions with various oil and gas companies, with Daylight Energy Ltd. being the most recent.

Notes:

1. Member of the audit committee.
2. Member of the compensation committee.
3. Member of the reserves committee.
4. Member of the environment, health and safety committee.

As a group, the directors and executive officers of the Corporation beneficially own, control or direct, directly or indirectly, 2,448,115 Common Shares, representing approximately three percent of the outstanding Common Shares as at March 19, 2013.

Corporate Cease Trade Orders

To the knowledge of management of the Corporation, no director or executive officer of the Corporation is, or within the 10 years before the date of this AIF, has been, a director, chief executive officer or chief financial officer of any other issuer that:

a) was the subject of a cease trade or similar order or an order that denied the other issuer access to any exemptions under Canadian securities legislation that lasted for a period of more than 30 consecutive days that was issued while the director or executive officer was acting in the capacity as director, chief executive officer or chief financial officer; or

b) was subject to a cease trade or similar order or an order that denied the relevant issuer access to any exemption under securities legislation that lasted for a period of more than 30 consecutive days that was issued after the director or executive officer ceased to be a director, chief executive officer or chief financial officer and which resulted from an event that occurred while the person was acting in the capacity as director, chief executive officer or chief financial officer.

Bankruptcies

To the knowledge of management of the Corporation, no director or executive officer, or any shareholder holding a sufficient number of securities of the Corporation to affect materially the control of the Corporation, or a personal holding company of any such person:

a) is, at the date of this AIF or has been within the 10 years before the date of this AIF, 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; or

b) has, within the 10 years before the date of this AIF, become 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 the assets of the director, officer or shareholder.

Penalties or Sanctions

To the knowledge of management of the Corporation, no director or executive officer, or any shareholder holding a sufficient number of securities of the Corporation to affect materially the control of the Corporation, has:

a) been subject to any penalties or sanctions imposed by a court relating to Canadian securities legislation or by a Canadian securities regulatory authority or has entered into a settlement agreement with the Canadian securities regulatory authority; or

b) been subject to 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.

Conflicts of Interest

The directors and officers of the Corporation may participate in activities and investments in the oil and gas industry outside the scope of their engagement or employment as directors or officers of the Corporation. As a result, the directors and officers may become subject to conflicts of interest. The ABCA provides that, in the event that a director has an interest in a contract or proposed contract or agreement, the director shall disclose his interest in such contract or agreement and shall refrain from voting on any matter in respect of such contract or agreement unless otherwise provided under the ABCA. To the extent that conflicts of interest arise, such conflicts will be resolved in accordance with the provisions of the ABCA, the written mandate of the Board of Directors and the Corporation's corporate governance policies.

As at the date hereof, the Corporation is not aware of any existing or potential material conflicts of interest between the Corporation and a director or officer of the Corporation.

AUDIT COMMITTEE

Composition of the Audit Committee, Charter and Review of Services

The members of the Audit Committee of the Board of Directors are Keith Macdonald (Chair), Murray Smith and Peter Bannister.

The Audit Committee of the Board of Directors operates under a written charter that sets out its responsibilities and composition requirements. A copy of the charter is attached to this AIF as Schedule "C".

The Audit Committee charter requires all members of the Audit Committee to be financially literate and independent within the meaning of applicable securities laws. All members of the Audit Committee meet these requirements.

The Audit Committee charter requires that any non-audit services by the Corporation's auditors must be pre-approved by the Audit Committee. The Audit Committee has passed a resolution providing the Chairman of the Audit Committee with delegated authority to approve the provision of non-audit services by the Corporation's auditors from time to time, provided that: (i) such services are provided pursuant to a written engagement letter setting out the services to be provided and the applicable fees; (ii) the provision of such services is otherwise in compliance with the Audit Committee's charter; (iii) such services could not be reasonably seen to result in the auditors performing any management function, auditing their own work or serving in an advocacy role on behalf of the Corporation; (iv) the fees for such services do not exceed $50,000 per engagement; and (v) the Chairman reports to the Committee at the next regularly scheduled meeting any approval of non-audit services made pursuant to the authority delegated under the resolution. The Audit Committee also pre-approves all audit services and the fees to be paid.

Education and Experience of Members

The education and experience of each director relevant to the performance of his duties as a member of the Audit Committee are described below.

Keith Macdonald

Mr. Macdonald is currently the President of Bamako Investment Management Ltd., a private holding and financial consulting company.

Mr. Macdonald is Chairman, President, CEO and director of EFL Overseas, Inc. as well as director of Bellatrix Exploration Ltd., Holloman Energy Corporation, Madalena Ventures Inc., Mountainview Energy Ltd., Rocky Mountain Dealerships Inc., WCSB Oil and Gas Royalty Income 2010 Management Corp. and WCSB Oil and Gas Royalty Income 2010-II Management Corp. He has served as chair and/or a member of the audit committee of each of those companies, as well as several other public oil and gas companies for which he has been a director. Mr. Macdonald was also formerly a director of Breaker Energy Ltd. prior to its sale in 2009.

From 1994 to January 1999 Mr. Macdonald was vice president of finance and a director of New Cache Petroleum Ltd. Mr. Macdonald founded New Cache Petroleum Ltd. in 1988 and was its president until a merger in 1994.

Mr. Macdonald holds the Chartered Accountants designation, achieved in 1980, and a Bachelor of Commerce degree (Accounting and Finance Major) from University of Calgary in 1978.

Murray Smith

Mr. Smith is the president of a private consulting company, Murray Smith and Associates and a director of Critical Control Business Solutions and Williams Companies, Inc. Mr. Smith also serves on the board of four private companies. Prior thereto, Mr. Smith was an Official Representative of the Province of Alberta to the United States of America until 2007. Prior thereto, he was a member of the Legislative Assembly in the Province of Alberta serving in four different Cabinet portfolios – Energy, Gaming, Labour, and Economic Development from 1993 to 2005.

From 1998-2004 Mr. Smith Mr. Smith was a member of the Government of Alberta Treasury Board (responsible for the annual budget for Alberta) and a contributing member to Alberta's debt elimination in 2004.

Mr. Smith has a degree in Economics from the University of Calgary (1971) and is a graduate of the London Business School Senior Executive Program (2000).

Peter Bannister

Mr. Bannister is currently the president of Destiny Energy Inc., a privately owned oil and gas company and is chairman of Crescent Point Energy Corp., a TSX listed company. Until its sale in February of 2007, Mr. Bannister was Vice-President, Exploration and a director of Mission Oil and Gas Inc., a TSX listed company. Prior to thereto, he was Vice-President, Exploration of StarPoint Energy Inc. before its conversion into a royalty trust and President and a director of Impact Energy Inc., both TSX listed companies. Mr. Bannister previously held the position of Vice-President of Corporate Development of Startech Energy Inc. until it was acquired by ARC Resources Ltd. at the end of 2000 and also held positions as Vice-President, Exploration and Development and a director of Boomerang Resources Ltd. and Laurasia Resources Limited, both publicly traded oil and gas companies. Mr. Bannister served on the Audit Committee of Breaker Energy Ltd. until its sale in 2009.

Mr. Bannister graduated from the University of Calgary in 1981 with a Major in Geology and a Minor in Economics. He was initially employed by Sproule Associates Limited as a senior geologist. Later, as a partner, he participated in exploration and property evaluation throughout Western Canada, the United States and the United Kingdom. He spent a number of years managing private capital and developing and executing drilling and acquisition opportunities for investors. Since 1993, Mr. Bannister has been actively involved in publicly-traded oil and gas companies.

External Auditor Service Fees

KPMG LLP are the auditors of the Corporation. KPMG LLP have been the auditors of the Corporation since May 5, 2010. Prior thereto, Collins Barrow Chartered Accountants LLP were the auditors of the Corporation.

The following table sets out the aggregate fees billed by KPMG LLP to the Corporation in each of the last two fiscal years.

Year	**Audit Fees(1)**	**Audit-Related Fees**	**Tax Fees(2)**	**All Other Fees**
2012	$177,500	$67,000	$101,906	$14,500
2011	$293,500	$nil	$54,500	$165,500

Notes:

(1) Audit fees consist of fees for the audit of annual financial statements or services that are normally provided in connection with statutory and regulatory filings or engagements. During fiscal 2011 and 2012, the services provided in this category included quarterly review fees.

(2) Fees for tax compliance, tax advice and tax planning.

INDUSTRY CONDITIONS

Restrained Pipeline Capacity and Differential Volatility

Western Canada and North Dakota have seen significant growth in crude production volumes over recent years. This has resulted in pressure on the pipeline take-away capacity, leading to apportionment on the main lines and, in turn, backed-up local feeder pipelines. This has contributed to a widening of, and increased volatility in, the light oil pricing differential between WTI and Edmonton Par and the medium/heavy oil pricing differential between WTI and Cromer/WCS/Hardisty. Although pipeline expansions are ongoing and producers are increasingly turning to rail as an alternative means of transportation, the lack of firm pipeline capacity continues to affect the oil and natural gas industry and limit the ability to produce and to market production. In addition, the pro-rationing of capacity on the interprovincial pipeline systems also continues to affect the ability to export oil and natural gas.

Availability of Services

The availability of the services necessary to drill and complete the types of horizontal oil wells that form a substantial portion of Surge's planned exploration and development activities in 2013 remains constrained due to increased demand and competition for such services. Surge does not anticipate that, at current commodity prices, such constraint will be alleviated in the near future.

Legislation and Regulation

The oil and natural gas industry is subject to extensive controls and regulations governing its operations (including land tenure, exploration, development, production, refining, transportation and marketing) imposed by legislation enacted by various levels of government and with respect to pricing and taxation of oil and natural gas by agreements among the governments of Canada, Alberta, Saskatchewan and Manitoba, all of which should be carefully considered by investors in the oil and natural gas industry. It is not expected that any of these controls or regulations will affect the operations of Surge in a manner materially different than they would affect other oil and natural gas producers of similar size. All current legislation is a matter of public record and Surge is unable to predict what additional legislation or amendments may be enacted. Some of the principal aspects of legislation, regulations and agreements governing the oil and natural gas industry are described further below.

Pricing and Marketing – Oil

The producers of oil are entitled to negotiate sales contracts directly with oil purchasers, with the result that the market determines the price of oil. Oil prices are primarily based on worldwide supply and demand. The specific price depends in part on oil quality, prices of competing fuels, distance to market, the value of refined products, the supply/demand balance, and contractual terms of sale. Oil exporters are also entitled to enter into export contracts with terms not exceeding one year in the case of light crude oil and two years in the case of heavy crude oil, provided that an order approving such export has been obtained from the National Energy Board of Canada (the "NEB"). Any 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 licence from the NEB and the issuance of such a licence requires a public hearing and the approval of the Governor in Council.

Pricing and Marketing – Natural Gas

The price of natural gas is determined by negotiation between buyers and sellers. Natural gas exported from Canada is subject to regulation by the NEB and the Government of Canada. Exporters are free to negotiate prices and other terms with purchasers, provided that the export contracts must continue to meet certain other criteria prescribed by the NEB and the Government of Canada. Natural gas (other than propane, butane and ethane) exports for a term of less than two years or for a term of two to 20 years (in quantities of not more than 30,000 m3/day), must be made pursuant to an NEB order. Any natural gas export to be made pursuant to a contract of longer duration (to a maximum of 25 years) or for a larger quantity requires an exporter to obtain an export licence from the NEB and the issuance of such a licence requires a public hearing and the approval of the Governor in Council.

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

Provincial Royalties and Incentives

General

In addition to federal regulation, each province has legislation and regulations that govern land tenure, royalties, production rates, environmental protection and other matters. The royalty regime is a significant factor in the profitability of crude oil, natural gas, natural gas liquids and sulphur production. Royalties payable on production from lands other than Crown lands are determined by negotiations between the mineral owner and the lessee, although production from such lands is also subject to certain provincial taxes and royalties. Operations not on Crown lands and subject to the provisions of specific agreements are also usually subject to royalties negotiated between the mineral owner and the lessee. These royalties are not eligible for incentive programs sponsored by various governments as discussed below. Crown royalties are determined by governmental regulation and are generally calculated as a percentage of the value of the gross production. 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 the western Canadian provinces have established incentive programs for exploration and development. Such programs often provide for royalty rate reductions, royalty holidays and tax credits for the purpose of encouraging oil and natural gas exploration or enhanced recovery projects. The programs are designed to encourage exploration and development activity by improving earnings and cash flow within the industry. Royalty holidays and reductions would reduce the amount of Crown royalties paid by oil and natural gas producers to the provincial governments and would increase the net income and funds from operations of such producers. However, the trend in recent years has been for provincial governments to allow such incentive programs to expire without renewal, and consequently few such incentive programs are currently operative.

Saskatchewan

In Saskatchewan, crude oil Crown royalties and freehold production tax depend on 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. Newly drilled oil wells in Saskatchewan qualify for "volume based" incentives ranging from 0 to 16,000 cubic metres, 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". Newly drilled qualifying exploratory gas wells in Saskatchewan qualify for a 25,000,000 cubic metre "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 Surge'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, with a base royalty rate of 5%, which represents the minimum royalty rate, and a maximum marginal royalty rate of 30%.

Alberta

In Alberta, the Crown royalty rates on conventional oil and natural gas fluctuate, depending on when a well was drilled, well depth, well production volume and the price of oil and natural gas. On October 25, 2007, the Alberta Government introduced a new royalty regime which became effective on January 1, 2009 applicable to all conventional oil and natural gas wells in Alberta ("New Royalty Regime"). The New Royalty Regime assesses the applicable royalty rate on a well by well basis using a sliding scale which takes into account the price of oil and/or natural gas and the well's production volumes. On November 19, 2008 and November 24, 2008 the Alberta Government announced an optional transitional royalty program ("Transitional Program"). On March 11, 2010 the Alberta Government announced modifications to the New Royalty Regime and the Transitional Program ("Modified Regime").

Under the New Royalty Regime the royalty reserved to the Alberta Crown on conventional oil production ranges from zero percent (0%) to fifty percent (50%) and is capped at fifty percent once the price of conventional oil reaches $120 per barrel. The royalty applicable to natural gas production under the new royalty regime ranges from five percent (5%) to fifty percent

(50%) and is capped once the price of natural gas reaches $17.75 per gigajoule. The new royalty regime has retained the Natural Gas Deep Drilling Program and the Deep Oil Exploration Program. The new royalty regime also sets royalties for natural gas liquids at forty percent (40%) for pentanes and thirty percent (30%) for butanes and propane.

The Modified Regime became effective on January 1, 2011 and reduces the maximum royalty rates under the New Royalty Regime as follows: for conventional oil production from fifty percent (50%) to forty percent (40%) and for natural gas from fifty percent (50%) to thirty six percent (36%). The Modified Regime also made permanent the 5% maximum royalty rate on the first 12 production months, 50,000 barrels of oil production or 500 million cubic feet (MMcfe) of gas production from a well, whichever is reached first.

The Transitional Program, as amended, applies to conventional oil and natural gas wells drilled to measured depths between 1,000 to 3,500 meters between November 19, 2008 and December 31, 2010. For each well, the producer can make a one time election to produce the well under the old royalty regime or the New Royalty Regime. As of January 1, 2014 all production subject to the Transitional Program will revert to the New Royalty Regime, as modified. The Natural Gas Deep Drilling and Deep Oil Exploration programs are not available to wells producing under the Transitional Program. Wells subject to the Transitional Program are permitted to switch to the Modified Regime after January 1, 2011.

For conventional oil produced under the Transitional Program, the royalty reserved to the Alberta Crown is variable depending on the pools' vintage (when the pool was discovered), oil density, well production volume, and the price of oil. The royalty is capped at thirty-five percent (35%), which maximum is reached at an oil price of approximately $30 per barrel, depending on other factors such as production rates.

For natural gas produced under the Transitional Program, the royalty reserved to the Alberta Crown varies depending on the vintage, production volume and the inflation adjusted price of gas less adjustments for the cost of processing the Crown's share of the gas. The royalty will vary between fifteen percent (15%) to thirty-five percent (35%). The maximum is reached at a natural gas price of approximately $3.70 per gigajoule, depending on other factors such as production rates.

Manitoba

In Manitoba, the royalty amount payable on oil produced from Crown lands depends on the classification of the oil produced as "old oil" (produced from a well drilled prior to April 1, 1974 that does not qualify as new oil or third tier oil), "new oil" (oil that is not third tier oil and is produced from a well drilled on or after April 1, 1974 and prior to April 1, 1999, from an abandoned well re-entered during that period, from an old oil well as a result of an enhanced recovery project implemented during that period, or from a horizontal well), "third tier oil" (oil produced from a vertical well drilled after April 1, 1999, an abandoned well re-entered after that date, an inactive vertical well activated after that date, a marginal well that has undergone a major workover, or from an old oil well or a new oil well as a result of an enhanced recovery project implemented after that date), or "holiday oil" (oil that is exempt from any royalty or tax payable). Royalty rates are calculated on a sliding scale and based on the monthly oil production from a spacing unit, or oil production allocated to a unit tract under a unit agreement or unit order from the Minister. For horizontal wells, the royalty on oil produced from Crown lands is calculated based on the amount of oil production allocated to a spacing unit in accordance with the applicable regulations.

Royalties payable on natural gas production from Crown lands are equal to 12.5 percent of the volume of natural gas sold.

Producers of oil and natural gas from freehold lands in Manitoba are required to pay monthly freehold production taxes. The freehold production tax payable on oil is calculated on a sliding scale based on the monthly production volume and the classification of oil as old oil, new oil, third tier oil and holiday oil. Producers of natural gas from freehold lands in Manitoba are required to pay a monthly freehold production tax equal to 1.2 percent of the volume sold. There is no freehold production tax payable on gas consumed as lease fuel.

The Government of Manitoba maintains a Drilling Incentive Program (the "Program") with the intent of promoting investment in the sustainable development of petroleum resources. The Program provides the licensee of newly drilled wells, or qualifying wells where a major workover has been completed, with a "holiday oil volume" pursuant to which no Crown royalties or freehold production taxes are payable until the holiday oil volume has been produced. Under the Program, wells drilled for purposes of injection (or wells converted to injection prior to producing predetermined volumes of oil) in an approved enhanced oil recovery project earn a one-year holiday for portions of the project area.

The Program consists of the following components:

- *New Well Incentive* provides licensees of newly drilled, non-horizontal wells drilled prior to January 1, 2014 with a holiday oil volume to a maximum of 10,000 m^3;
- *Deep Drilling Incentive* provides licensees who drill a well to a total depth sufficient to penetrate the Devonian Duperow formation with a holiday oil volume of 20,000 m^3, and licensees who drill a well deeper than the Devonian Three Forks formation can make a one-time assignment of up to 10,000 m^3 of holiday oil volume earned through previous drilling or major workovers to such well's holiday oil volume;
- *Horizontal Well Initiative* provides licensees of horizontal wells drilled prior to January 1, 2014 with a holiday oil volume of 10,000 m^3, and a horizontal leg drilled from an existing horizontal well on or after January 1, 2009 and prior to January 1, 2014 will earn an additional holiday royalty volume of 3,000 m^3;
- *Marginal Well Major Workover Incentive* provides licensees of marginal wells where a major workover is completed prior to January 1, 2014 with a holiday oil volume of 500 m^3 ,with a marginal oil well defined as an abandoned well or a well that was either not operated over the previous 12 months or produced oil at an average rate of less than 1 m^3 per operating day; and
- *Injection Well Incentive* provides a one year exemption from the payment of Crown royalties or freehold production taxes on production allocated to a unit tract in which a well is drilled or converted to water injection.

Further, holiday oil volumes earned by a newly drilled well or a marginal well that has undergone a major workover can be transferred to a Holiday Oil Volume Account at the request of the licensee, the purpose of which is to optimize the value of holiday oil volumes earned by providing a company with the flexibility of allocating holiday oil volumes earned among new wells.

Climate Change Regulation

Federal

In December 2002, the Government of Canada ratified the Kyoto Protocol ("Kyoto Protocol"), which requires a reduction in greenhouse gas emissions by signatory countries between 2008 and 2012. The Kyoto Protocol officially came into force on February 16, 2005 and commits Canada to reduce its greenhouse gas ("GHG") emissions levels to 6% below 1990 "business-as-usual" levels by 2012. In December of 2011, the Government of Canada announced that it would withdraw from the Kyoto Protocol.

On April 26, 2007, the Government of Canada released "Turning the Corner: An Action Plan to Reduce Greenhouse Gases and Air Pollution" (the "Action Plan") which set forth a plan for regulations to address both greenhouse gases and air pollution. An update to the Action Plan, "Turning the Corner: Regulatory Framework for Industrial Greenhouse Gas Emissions" was released on March 10, 2008 (the "Updated Action Plan"). Although draft regulations for the implementation of the Updated Action Plan were intended to be published in the fall of 2008 and become binding on January 1, 2010, only certain regulations related to the transport industry and clean fuels have been proposed to date. Further, representatives of the Government of Canada have indicated that the proposals contained in the Updated Action Plan will be modified to ensure consistency with the direction ultimately taken by the United States with respect to greenhouse gas emissions regulation. The stated goal of the Updated Action Plan, as currently drafted, is to reduce greenhouse gas emissions by 17% below 2005 levels by 2020 and 60-70% by 2050. As noted above, the goal has now been modified by the Government of Canada. The approach of the Unites States may include an absolute cap on emissions combined with allowances to be used for compliance that may be partially auctioned off to regulated entities. It is also unclear whether the approach adopted by the United States will provide for the payment into a technology fund as a compliance mechanism, as is currently permitted in Alberta and by the Updated Action Plan. As a result, many provisions of the Updated Action Plan are expected to be significantly modified.

It is expected that any regulations eventually implemented by the Government of Canada will have an impact of the oil and gas industry as a whole, which could result in increased costs for Surge to comply with such legislation. In the meantime, Surge will continue to monitor the policies of the Government of Canada and any resulting legislation with respect to GHG emissions. The US Environmental Protection Agency ("EPA") is proceeding to regulate greenhouse gases under the Clean Air Act. This EPA action is subject to legal and political challenges, the outcome of which cannot be predicted. The ultimate form of Canadian regulation is anticipated to be strongly influenced by the regulatory decisions made within the United States. Various states have enacted or are evaluating low carbon fuel standards, which may affect access to market for crude oils with higher emissions intensity.

Alberta

Alberta enacted the *Climate Change and Emissions Management Act* (the "CCEMA") on July 1, 2007, amending it through the *Climate Change and Emissions Management Amendment Act* which received royal assent on November 4, 2008. The CCEMA is based on an emissions intensity approach similar to the Updated Action Plan and aims for a 50% reduction from 1990 emissions relative to GDP by 2020. Alberta facilities emitting more than 100,000 tonnes of greenhouse gases a year are subject to comply with the CCEMA. At this point Surge does not own or anticipate owning or operating any facilities which emit more than 100,000 tonnes of GHGs per year.

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 Surge.

Manitoba

The Government of Manitoba has commenced public consultations with respect to the development of a cap and trade system to reduce greenhouse gas emissions. The enactment of *The Climate Change and Emissions Reductions Act* (Manitoba) sets emission reduction targets as of December 31, 2012 at 6% below 1990 emissions and details the commitment of the Government of Manitoba to various initiatives in an effort to reduce greenhouse gas emissions, but no legislation has been effected which imposes mandatory emission reduction targets on emitters.

Land Tenure

Crude oil and natural gas located in the western Canadian provinces is owned both by the respective provincial governments and by private individuals. Provincial governments grant rights to explore for and produce oil and natural gas pursuant to leases, licenses and permits for varying periods and on conditions set forth in provincial legislation, including requirements to perform specific work or make payments. Where oil and natural gas is privately owned, rights to explore for and produce such oil and natural gas are granted by lease on such terms and conditions as may be negotiated.

United States

Surge's wholly-owned subsidiary, Surge Energy USA Inc., owns oil and natural gas properties and related assets in North Dakota in the United States. Surge's oil and natural gas operations in the United States are regulated by administrative agencies under statutory provisions of the state of North Dakota. These statutory provisions regulate matters such as the exploration for and production of crude oil and natural gas, including provisions related to permits for the drilling of wells, bonding requirements in order to drill or operate wells, the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled, and the abandonment of wells. Surge's operations in the United States are also subject to various conservation laws and regulations which regulate matters such as the size of drilling and spacing units or proration units, the number of wells which may be drilled in an area, and the unitization or pooling of crude oil and natural gas properties. In addition, state conservation laws sometimes establish maximum rates of production from crude oil and natural gas wells, restrict or prohibit the venting or flaring of natural gas and impose certain requirements regarding the rateability or fair apportionment of production from fields and individual wells.

RISK FACTORS

An investment in Common Shares would be subject to certain risks. Investors should carefully consider the following risk factors:

Operational Risks

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

Oil and natural gas exploration and development activities are dependent on the availability of drilling and related equipment in the particular areas where such activities will be conducted. Demand for such limited equipment or access restrictions may affect the availability of such equipment to Surge and may delay exploration and development activities.

Oil and natural gas exploration and development activities are dependent on access to areas where operations are to be conducted. Seasonal weather variations, including freeze-up and break-up, affect access in certain circumstances. Unexpected adverse weather conditions, such as flooding or prolonged break-up, can have a significant negative impact on capital expenditures, operations and costs.

To the extent Surge is not the operator of its oil and natural gas properties, it is dependent on such operators for the timing of activities related to such properties and is largely unable to direct or control the activities of the operators. Payments from production generally flow through the operator and there is a risk of delay and additional expense in receiving such revenues if the operator becomes insolvent. Although Surge intends to operate the majority of its properties, there is no guarantee that it will remain operator of such properties or that Surge will operate other properties it may acquire in the future.

In addition, the success of Surge will be largely dependent upon the performance of its management and key employees. Surge does not have any key man insurance policies and, therefore, there is a risk that the death or departure of any member of management or any key employee could have a material adverse effect on Surge.

Surge's ability to market oil and natural gas from its wells also depends upon numerous other factors beyond its control, including, among other things, the availability of natural gas processing and storage capacity, the availability of pipeline capacity, the price of oilfield services and the effects of inclement weather. Because of these factors, Surge may be unable to market some or all of the oil and natural gas it produces or to obtain favourable prices for the oil and natural gas it produces.

Volatility of Oil and Natural Gas Prices and Markets

Surge's financial performance and condition are substantially dependent on the prevailing prices of oil and natural gas which are unstable and subject to fluctuation. Fluctuations in oil or natural gas prices could have an adverse effect on Surge's operations and financial condition and the value and amount of its reserves. Prices for crude oil fluctuate in response to global and North American supply of and demand for oil, market performance and uncertainty and a variety of other factors which are outside the control of Surge including, but not limited, to the world economy and OPEC's ability to adjust supply to world demand, government regulation, political stability and the availability of alternative fuel sources. In addition, the prices received by Surge for its oil are subject to differentials against such benchmarks as WTI and Edmonton Par which can fluctuate substantially and result in Surge realizing prices substantially below such benchmarks. Natural gas prices are influenced primarily by factors within North America, including North American supply and demand, economic performance, weather conditions and availability and pricing of alternative fuel sources.

Decreases in oil and natural gas prices realized by Surge will result in reduced net production revenue and may change the economics of producing from some wells, which could result in a reduction in the volume of Surge's reserves. Any further substantial declines in the prices of crude oil or natural gas could also result in delay or cancellation of existing or future drilling, development or construction programs or the curtailment of production. All of these factors could result in a material decrease in Surge's net production revenue, cash flows and profitability causing a reduction in its oil and gas acquisition and development activities. In addition, bank borrowings available to Surge will in part be determined by Surge's borrowing base. A sustained material decline in prices from historical average prices could further reduce such borrowing base, therefore reducing the bank credit available and could require that a portion of its bank debt be repaid.

Surge may enter into agreements to receive fixed prices on its oil and natural gas production to offset the risk of revenue losses if commodity prices decline; however, if commodity prices increase beyond the levels set in such agreements, Surge will not benefit from such increases.

Sour Natural Gas

Some of the Corporation's current or future properties include wells that produce sour natural gas and facilities that process sour natural gas. An accidental discharge or leak of sour natural gas can be fatal or cause serious injury. The dangers associated with drilling for, producing, processing and transporting sour natural gas necessitate increased environmental, health and safety compliance costs to Surge and any accidental discharge or leak of sour natural gas could lead to significant liabilities to Surge. Surge has implemented policies and protocols to address this risk, but it is not possible for any issuer to eliminate all of the risks associated with producing, processing and transporting sour natural gas.

Environmental Concerns

Many aspects of the oil and natural gas business present environmental risks and hazards, including the risk that Surge may be in noncompliance with an environmental law, regulation, permit, licence, or other regulatory approval, possibly unintentionally or without knowledge. Such risks may expose Surge to fines or penalties, third party liabilities or to the requirement to remediate, which could be material.

The operational hazards associated with possible blowouts, accidents, oil spills, natural gas leaks, fires, or other damage to a well or a pipeline may require Surge to incur costs and delays to undertake corrective actions, could result in environmental damage or contamination or could result in serious injury or death to employees, consultants, contractors or members of the public, creating the potential for significant liability to Surge. Also, the occurrence of any such incident could damage Surge's reputation in the surrounding communities and make it more difficult for Surge to pursue its operations in those areas.

Compliance with environmental laws and regulations could materially increase Surge's costs. Surge may incur substantial capital and operating costs to comply with increasingly complex laws and regulations covering the protection of the environment and human health and safety. In particular, Surge may be required to incur significant costs to comply with future federal or provincial greenhouse gas emissions reduction requirements or other regulations, if enacted.

Although Surge maintains insurance consistent with prudent industry practice, it is 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. Accordingly, Surge's properties may be subject to liability due to hazards that cannot be insured against, or that have not been insured against due to prohibitive premium costs or for other reasons. It is also possible that changing regulatory requirements or emerging jurisprudence could render such insurance of less benefit to Surge.

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. Surge utilizes hydraulic fracturing in a significant portion of the light oil wells it drills and completes. Negative public perception of hydraulic fracturing may place pressure on governments in the jurisdictions where Surge operates to implement additional regulatory requirements or limitations on the utilization of hydraulic fracturing, which in turn could restrict Surge's operations and increase its costs.

Availability of Services

The availability of the services necessary to drill and complete the types of horizontal oil wells that form a substantial portion of Surge's planned exploration and development activities in 2013 remains constrained due to increased demand and competition for such services. Such constraint may increase the costs of such services or result in the delay of planned exploration and development activities.

Reserve Estimates

There are numerous uncertainties inherent in evaluating quantities of reserves and the net present value of future net revenue to be derived therefrom, including many factors beyond the control of Surge. The reserves information contained in the Sproule Report and set forth herein, including information respecting the net present value of future net revenue from reserves, represents an estimate only. This estimate is based on a number of assumptions relating to factors such as initial production rates, production decline rates, ultimate recovery of reserves, timing and amount of capital expenditures, marketability of production, future prices of oil and natural gas, 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 Sproule Report was prepared and many of these assumptions are subject to change and are beyond the control of Surge. Ultimately, the actual reserves attributable to Surge's properties will vary from the estimates contained in the Sproule Report and those variations may be material and affect the market price of the Common Shares.

Reserve Replacement

Surge's future oil and natural gas reserves and production and the cash flows to be derived therefrom are highly dependent on successfully acquiring or discovering new reserves. Without the continual addition of new reserves, any existing reserves Surge may have at any particular time and the production therefrom will decline over time as such existing reserves are exploited. A future increase in reserves will depend not only on Surge's ability to develop any properties it may have from time to time, but also on its ability to select and acquire suitable producing properties or prospects. There can be no assurance that Surge's future exploration and development efforts will result in the discovery and development of additional commercial accumulations of oil and natural gas.

Industry Regulation and Competition

There is strong competition relating to all aspects of the oil and natural gas industry. Surge will actively compete for capital, skilled personnel, undeveloped land, reserve acquisitions, access to drilling rigs, service rigs and other equipment, access to processing facilities and pipeline and refining capacity, and in all other aspects of its operations with a substantial number of other organizations, many of which may have greater technical and financial resources than Surge. Some of those organizations not only explore for, develop and produce oil and natural gas but also carry on refining operations and market petroleum and other products on a world-wide basis and as such have greater and more diverse resources on which to draw. Surge's ability to increase reserves and production in the future will depend not only on its ability to develop its present properties, but also on its ability to select and acquire suitable producing properties or prospects for exploratory drilling.

The marketability of oil and natural gas acquired or discovered will be affected by numerous factors beyond the control of Surge. These factors include reservoir characteristics, market fluctuations, the proximity and capacity of oil and natural gas pipelines and processing equipment and government regulation. Oil and natural gas operations (exploration, production, pricing, marketing, transportation and royalty rates) are subject to extensive controls and regulations imposed by various levels of government, including those described above under the heading "Industry Conditions", which may be amended from time to time. Surge's oil and natural gas operations may also be subject to compliance with federal, provincial and local laws and regulations controlling the discharge of materials into the environment or otherwise relating to the protection of the environment. Changes to the regulation of the oil and gas industry in jurisdictions in which Surge operates may adversely impact Surge's ability to economically develop existing reserves and add new reserves.

Variations in Foreign Exchange Rates and Interest Rates

Surge's expenses will be denominated in Canadian dollars, while the price of oil and natural gas will generally be denominated in U.S. dollars or impacted by the Canadian dollar to U.S. dollar exchange rate. As the exchange rate for the Canadian dollar versus the U.S. dollar increases, Surge will generally receive fewer Canadian dollars for its production. If the value of the Canadian dollar against the U.S. dollar increases, the financial results of Surge may be negatively affected. Surge's management may initiate certain hedges to mitigate these risks. Future fluctuations in the Canadian/United States foreign exchange rate may impact the future value of Surge's reserves as determined by independent evaluators. In addition, variations in interest rates could result in a significant change in the amount Surge will pay to service debt, potentially adversely affecting the value of the Common Shares.

Price Volatility of Publicly Traded Securities

In recent years, the securities markets in Canada and the United States have experienced a high level of price and volume volatility, and the market price of securities of many companies, particularly those considered to be development stage companies, has experienced wide fluctuations in price which have not necessarily been related to the operating performance, underlying asset values or prospects of such companies. There can be no assurance that continual fluctuations in price will not occur. It is likely that the market price for the Common Shares will be subject to market trends generally, notwithstanding the financial and operational performance of Surge.

Substantial Capital Requirements; Liquidity

Surge may have to make substantial capital expenditures for the acquisition, exploration, development and production of oil and natural gas reserves in the future. If revenues or reserves decline, Surge may have limited ability to expend the capital necessary to undertake or complete future drilling programs. There can be no assurance that debt or equity financing or cash generated by operations will be available or sufficient to meet these requirements or for other corporate purposes or, if debt or equity financing is available, that it will be on terms acceptable to the company. Moreover, future activities may require Surge to alter its capitalization significantly. The inability of the company to access sufficient capital for its operations could have a material adverse effect on its financial condition, results of operations or prospects.

Issuance of Debt

From time to time Surge may enter into transactions to acquire assets or shares of other corporations. These transactions may be financed partially or wholly through debt, which may increase debt levels above industry standards. Surge's articles and by-laws do not limit the amount of indebtedness it may incur. The level of Surge's indebtedness from time to time could impair its ability to obtain additional financing in the future on a timely basis to take advantage of business opportunities that may arise.

Abandonment and Reclamation Costs

Surge 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 its 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.

Possible Failure to Realize Anticipated Benefits of Future Acquisitions

Surge may complete acquisitions to strengthen its position in the oil and natural gas industry and to create the opportunity to realize certain benefits including, among other things, potential cost savings. Achieving the benefits of any future acquisitions depends, in part, on successfully consolidating functions and integrating operations, procedures and personnel in a timely and efficient manner, as well as Surge's ability to realize the anticipated growth opportunities and synergies from combining the acquired businesses and operations with its own. The integration of acquired businesses requires the dedication of substantial management effort, time and resources which may divert management’s focus and resources from other strategic opportunities and from operational matters during this process. The integration process may result in the loss of key employees and the disruption of ongoing business, customer and employee relationships that may adversely affect Surge's ability to achieve the anticipated benefits of these and future acquisitions.

Delay in Cash Receipts and Credit Worthiness of Counterparties

In addition to the usual delays in payment by purchasers of oil and natural gas to the operators of Surge's properties, and by the operator to Surge, payments between any of such parties may also be delayed by restrictions imposed by lenders, delays in the sale or delivery of products, delays in the connection of wells to a gathering system, blowouts or other accidents, recovery by the operator of expenses incurred in the operation of Surge's properties or the establishment by the operator of reserves for such expenses. In addition, the insolvency or financial impairment of any counterparty owing money to Surge, including industry partners and marketing agents, could prevent Surge from collecting such debts.

Dilution

Common Shares, including rights, warrants, special warrants, subscription receipts and other securities to purchase, to convert into or to exchange into Common Shares, may be created, issued, sold and delivered on such terms and conditions and at such times as the Board may determine. In addition, Surge may issue additional Common Shares from time to time pursuant to Surge's stock option plan and stock incentive plan. The issuance of these Common Shares would result in dilution to holders of Common Shares.

Net Asset Value

Surge's net asset value will vary depending upon a number of factors beyond the control of Surge's management, including oil and natural gas prices. The trading price of the Common Shares is also determined by a number of factors which are beyond the control of management and such trading price may be greater than or less than the net asset value of Surge.

Reliance on Management

Shareholders will be dependent on the management of Surge in respect of the administration and management of all matters relating to Surge and its properties and operations. Investors who are not willing to rely on the management of Surge should not invest in Common Shares.

Permits and Licenses

The operations of Surge may require licenses and permits from various governmental authorities. There can be no assurance that Surge will be able to obtain all necessary licenses and permits that may be required to carry out exploration and development at its projects.

Title to Properties

Although title reviews will be done according to industry standards prior to the purchase of most oil and natural gas producing properties or the commencement of drilling wells as determined appropriate by management, such reviews do not guarantee or certify that an unforeseen defect in the chain of title will not arise to defeat a claim of Surge which could result in a reduction of Surge's interest in a property or well and the revenue received by Surge therefrom.

Aboriginal Claims

Aboriginal peoples have claimed aboriginal title and rights to resources and various properties in western Canada. Such claims, in relation to any of Surge's lands, if successful, could have an adverse effect on its operations.

Corporate Matters

To date, Surge has not paid any dividends on its outstanding Common Shares. Certain of the directors and officers of Surge are also directors and officers of other oil and gas companies involved in natural resource exploration and development, and conflicts of interest may arise between their duties as officers and directors of Surge, as the case may be, and as officers and directors of such other companies.

Failure to Maintain Listing of the Common Shares

The Common Shares are currently listed for trading on the facilities of the TSX. The failure of Surge to meet the applicable listing or other requirements of the TSX in the future may result in the Common Shares ceasing to be listed for trading on the

TSX, which would have a material adverse effect on the value of the Common Shares. There can be no assurance that the Common Shares will continue to be listed for trading on the TSX.

Structure of Surge

From time to time, Surge may take steps to organize its affairs in a manner that minimizes taxes and other expenses payable with respect to the operation of Surge and its subsidiaries. If the manner in which Surge structures its affairs is successfully challenged by a taxation or other authority, Surge and the holders of Common Shares may be adversely affected.

Changes in Legislation

It is possible that the Canadian federal and provincial government or regulatory authorities could choose to change the Canadian federal income tax laws, royalty regimes, environmental laws or other laws applicable to oil and gas companies and that any such changes could materially adversely affect Surge, its shareholders and the market value of the Common Shares.

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

There are no legal proceedings involving claims for damages for which the potential exposure is more than 10% of the Corporation's current assets to which the Corporation is or was a party or in respect of which any of its properties are or were subject during the year ended December 31, 2012, nor are there any such proceedings known to the Corporation to be contemplated, other than the following: Canadian Natural Resources Limited ("CNRL") has commenced an action against Surge claiming conversion, interference with economic relations, negligence and unjust enrichment. CNRL alleges that Surge has been producing gas belonging to CNRL at Valhalla and claims damages of $10,000,000, along with other forms of relief. The issues in dispute are the subject of a hearing before the Energy Resources Conservation Board scheduled to commence on May 21, 2013. Surge believes that any compensation which may become payable to CNRL is not likely to be material.

During the year ended December 31, 2012, there were (i) no penalties or sanctions imposed against the Corporation by a court relating to securities legislation or by a securities regulatory authority; (ii) no other penalties or sanctions imposed by a court or regulatory body against the Corporation that it believes would likely be considered important to a reasonable investor in making an investment decision; and (iii) no settlement agreements entered into by the Corporation with a court relating to securities legislation or with a securities regulatory authority.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

In connection with the Recapitalization, on April 13, 2010, the current directors and officers of the Corporation, with the exception of Murray Smith and Colin Davies, purchased 20,452 Common Shares at a price of $4.40 per Common Share, 1,099,413 Units at a price of $4.40 per Unit and 661,951 FT Units at a price of $4.40 per FT Unit. Each Unit consists of one Common Share and Performance Warrant while each FT Unit consists of one Common Share issued on a "flow-through" basis in accordance with the Tax Act and one Performance Warrant.

Each of James Pasieka, a director of the Corporation, and Thomas Cotter, the Corporate Secretary of the Corporation, is a partner of the national law firm Heenan Blaikie LLP, which law firm renders legal services to the Corporation. Surge paid an aggregate of $0.6 million in legal fees to Heenan Blaikei LLP during the year ended December 31, 2012 and $0.3 million in legal fees to Heenan Blaikie LLP during the year ended December 31, 2011.

Except as disclosed above or as may be disclosed elsewhere in this AIF, none of the directors, executive officers or principal shareholders of the Corporation, and no associate or affiliate of any of them, has or has had any material interest in any transaction or any proposed transaction which has materially affected or is reasonably expected to materially affect the Corporation or any of its affiliates.

AUDITOR, TRANSFER AGENT AND REGISTRAR

The auditor of the Corporation is KPMG LLP who has been the auditor since May 5, 2010.

The transfer agent and registrar for the Common Shares is Olympia Trust Company at its principal offices in Calgary, Alberta and Toronto, Ontario.

INTEREST OF EXPERTS

The Sproule Report and certain reserves estimates contained in filings made by the Corporation under National Instrument 51-102 – Continuous Disclosure Requirements during the year ended December 31, 2012 were prepared by Sproule. As at the date of this Annual Information Form, the directors, officers, employees and consultants of Sproule who participated in the preparation of the Sproule Report or such reserves estimates or who were in a position to directly influence the preparation or outcome of the preparation of the Sproule Report or such reserves estimates, as a group, owned, directly or indirectly, less than 1% of the outstanding Common Shares.

Certain audit reports contained in filings made by the Corporation under National Instrument 51-102 – Continuous Disclosure Requirements during the year ended December 31, 2009 were prepared by Collins Barrow Calgary LLP. KPMG LLP were appointed auditors of the Corporation on May 5, 2010. KPMG LLP are independent of the Corporation pursuant to the rules of professional conduct of the Institute of Chartered Accountants of Alberta. The previous auditors of the Corporation, Collins Barrow Calgary LLP, were independent of the Corporation pursuant to the rules of professional conduct of the Institute of Chartered Accountants of Alberta for the period during which they were the auditors of the Corporation.

ADDITIONAL INFORMATION

Additional information concerning the Corporation may be found under the Corporation's profile on SEDAR at www.sedar.com. Additional information, including information concerning directors' and officers' remuneration and indebtedness, principal holders of the Corporation's securities and securities authorized for issuance under equity compensation plans, will be contained in the information circular of the Corporation for the annual general meeting of the holders of Common Shares scheduled for **May 15th, 2013**. Additional financial information is provided in the Corporation's comparative financial statements and management's discussion and analysis for the year ended December 31, 2012.

SCHEDULE "A"

REPORT ON RESERVES DATA BY INDEPENDENT QUALIFIED RESERVES EVALUATOR OR AUDITOR

Form 51-101F2

Report on Reserves Data by Independent Qualified Reserves Evaluator or Auditor

Report on Reserves Data

To the Board of Directors of Surge Energy Inc. (the "Company"):

1. We have evaluated the Company's reserves data as at December 31, 2012. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2012, 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.

   We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook (the "COGE Handbook"), prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum (Petroleum Society).

3. 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.

4. The following table sets forth the estimated 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 by us as of December 31, 2012, 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 or Auditor	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 and Audit of the P&NG Reserves of Surge Energy Inc., As of December 31, 2012, prepared August 2012 to February 2013	Canada				
Total			**18,437**	**713,233**	**Nil**	**731,670**

5. In our opinion, the reserves data respectively evaluated by us have, in all material respects, been determined and are presented 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.

6. We have no responsibility to update the report referred to in paragraph 4 for events and circumstances occurring after its preparation date.

7. Because the reserves data are based on judgments 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
February 5, 2013

Original Signed by Khani Ghaffari, P.Eng.

Khani Ghaffari, P.Eng.
Senior Petroleum Engineer and Associate

Original Signed by Gary R. Finnis, P.Eng.

Gary R. Finnis, P.Eng.
Supervisor, Engineering and Partner

Original Signed by George Strother-Stewart, P.Geo

George Strother-Stewart, P.Geol.
Senior Petroelum Geologist and Partner

Original Signed by Cameron P. Six, P.Eng.

Cameron P. Six, P.Eng.
Vice-President, Engineering, Canada and Director

SCHEDULE "B"

FORM 51-101F3

REPORT OF MANAGEMENT AND DIRECTORS ON RESERVES DATA AND OTHER INFORMATION

Terms to which a meaning is ascribed in National Instrument 51-101 - Standards of Disclosure for Oil and Gas Activities have the same meaning herein.

Management of Surge Energy Inc. (the "**Corporation**") is responsible for the preparation and disclosure of information with respect to the Corporation's oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data, which are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2012, estimated using forecast prices and costs.

An independent qualified reserves evaluator has evaluated and reviewed the Corporation's reserves data. The report of the independent qualified reserves evaluator is presented in Schedule "A" to the Annual Information Form of the Corporation for the year ended December 31, 2012 (the "**AIF**").

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

(a) reviewed the Corporation's procedures for providing information to the independent qualified reserves evaluator, Sproule Associates Limited ("**Sproule**");

(b) met with Sproule to determine whether any restrictions affected the ability of Sproule to report without reservation; and

(c) reviewed the reserves data with management and with Sproule.

The Reserves Committee of the Board of Directors has reviewed the Corporation'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:

(d) the content and filing with securities regulatory authorities of Form 51-101F1, incorporated into the AIF, containing reserves data and other oil and gas information;

(e) the filing of Form 51-101F2, which is the report of Sproule on the reserves data; and

(f) the content and filing of this report.

Because the reserves data are based on judgements regarding future events, actual results will vary and the variations may be material. However, any variations should be consistent with the fact that reserves are categorized according to the probability of their recovery.

(signed) "P. Daniel O'Neil"

P. Daniel O'Neil, President & Chief Executive Officer

(signed) "Maxwell Lof"

Maxwell Lof, Vice-President, Finance and Chief Financial Officer

(signed) "Peter Bannister"

Peter Bannister, Director & Chairman of the Reserves Committee

(signed) "Paul Colborne"

Paul Colborne, Director & Chairman of the Board of Directors

March 19, 2013

SCHEDULE "C"

AUDIT COMMITTEE CHARTER

SURGE ENERGY INC.

AUDIT COMMITTEE CHARTER

Role and Objective

The Audit Committee is a committee of the Board of Directors of Surge Energy Inc. (the "**Corporation**") to which the Board has delegated its responsibility for oversight of the nature and scope of the annual audit, management's reporting on internal accounting standards and practices, financial information and accounting systems and procedures, financial reporting and statements and recommending, for Board approval, the audited consolidated financial statements and other mandatory disclosure releases containing financial information of the Corporation. The objectives of the Audit Committee are as follows:

1. to assist directors in fulfilling their legal and fiduciary obligations (especially for accountability) in respect of the preparation and disclosure of the financial statements of the Corporation and related matters;

2. to oversee the audit efforts of the external auditors of the Corporation;

3. to maintain free and open means of communication among the directors, the external auditors, the financial and senior management of the Corporation;

4. to satisfy itself that the external auditors are independent of the Corporation; and

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

The function of the Committee is one of oversight of management and the external auditors in the execution of their responsibilities. Management is responsible for the preparation, presentation and integrity of the financial statements of the Corporation, maintaining appropriate accounting and financial reporting principles and policies and implementing appropriate internal controls and procedures. The external auditors are responsible for planning and carrying out a proper audit of the annual financial statements of the Corporation and reviewing the interim financial statements of the Corporation prior to their filing with securities regulatory authorities and other procedures.

Composition of the Committee

1. The Audit Committee shall consist of at least three directors. The Board shall appoint one member of the Audit Committee to be the Chair of the Audit Committee.

2. Each director appointed to the Audit Committee by the Board must be independent. A director is independent if the director has no direct or indirect material relationship with the Corporation. A material relationship means a relationship which could, in the view of the Board, reasonably interfere with the exercise of the director's independent judgment. In determining whether a director is independent of management, the Board shall make reference to National Instrument 52-110 – *Audit Committees* or the then current legislation, rules, policies and instruments of applicable regulatory authorities.

3. Each member of the Audit Committee shall be "financially literate". In order to be financially literate, a director must be, at a minimum, able to read and understand financial statements that present a breadth and complexity of

accounting issues generally comparable to the breadth and complexity of issues expected to be raised by the Corporation's financial statements.

4. A director appointed by the Board to the Audit Committee shall be a member of the Audit Committee until replaced by the Board or until his or her resignation.

Meetings of the Committee

1. The Audit Committee shall convene a minimum of four times each year at such times and places as may be designated by the Chair of the Audit Committee and whenever a meeting is requested by the Board, a member of the Audit Committee, the auditors, or a senior officer of the Corporation. Meetings of the Audit Committee shall correspond with the review of the quarterly financial statements and management discussion and analysis of the Corporation.

2. Notice of each meeting of the Audit Committee shall be given to each member of the Audit Committee. The auditors shall be given notice of each meeting of the Audit Committee at which financial statements of the Corporation are to be considered and such other meetings as determined by the Chair and shall be entitled to attend each such meeting of the Audit Committee.

3. Notice of a meeting of the Audit Committee shall:

    (a) be in writing;

    (b) state the nature of the business to be transacted at the meeting in reasonable detail;

    (c) to the extent practicable, be accompanied by copies of documentation to be considered at the meeting; and

    (d) be given at least two business days prior to the time stipulated for the meeting or such shorter period as the members of the Audit Committee may permit.

4. A quorum for the transaction of business at a meeting of the Audit Committee shall consist of a majority of the members of the Audit Committee. However, it shall be the practice of the Audit Committee to require review, and, if necessary, approval of certain important matters by all members of the Audit Committee.

5. A member or members of the Audit Committee may participate in a meeting of the Audit Committee by means of such telephonic, electronic or other communication facilities, as permits all persons participating in the meeting to communicate adequately with each other. A member participating in such a meeting by any such means is deemed to be present at the meeting.

6. In the absence of the Chair of the Audit Committee, the members of the Audit Committee shall choose one of the members present to be Chair of the meeting. In addition, the members of the Audit Committee shall choose one of the persons present to be the Secretary of the meeting.

7. The Chairman of the Board, senior management of the Corporation and other parties may attend meetings of the Audit Committee; however the Audit Committee (i) shall meet with the external auditors independent of management as necessary, in the sole discretion of the Committee, but in any event, not less than quarterly; and (ii) may meet separately with management.

8. Minutes shall be kept of all meetings of the Audit Committee and shall be signed by the Chair and the Secretary of the meeting.

Duties and Responsibilities of the Committee

1. It is the responsibility of the Audit Committee to oversee the work of the external auditors, including resolution of disagreements between management and the external auditors regarding financial reporting. The external auditors shall report directly to the Audit Committee.

2. The Audit Committee shall, in the exercise of its powers, authorities and discretion so authorized, conform to any regulations or restrictions that may from time to time be made or imposed upon it by the Board or the legislation, policies or regulations governing the Corporation and its business.

3. It is the responsibility of the Audit Committee to satisfy itself on behalf of the Board that the Corporation's system of internal controls over financial reporting and disclosure controls and procedures are satisfactory for the purpose of:

   (a) identifying, monitoring and mitigating the principal risks;

   (b) ensuring compliance with legal, ethical and regulatory requirements;

   and to review with the external auditors their assessment of the internal controls over financial reporting and the disclosure controls of the Corporation, their written reports containing recommendations for improvement, and management's response and any follow-up to any identified weaknesses.

4. It is the responsibility of the Audit Committee to review the annual financial statements of the Corporation and, if deemed appropriate, recommend the financial statements to the Board for approval. This process should include but be not to be limited to:

   (a) reviewing and accepting, if appropriate, the annual audit plan of the external auditors of the Corporation, including the scope of audit activities, and monitor such plan's progress and results during the year;

   (b) reviewing changes in accounting principles, or in their application, which may have a material impact on the current or future years' financial statements;

   (c) reviewing significant accruals, reserves or other estimates such as the ceiling test calculation;

   (d) reviewing the methods used to account for significant unusual or non-recurring transactions;

   (e) ascertaining compliance with covenants under loan agreements;

   (f) reviewing disclosure requirements for commitments and contingencies;

   (g) reviewing adjustments raised by the external auditors, whether or not included in the financial statements;

   (h) reviewing unresolved differences between management and the external auditors;

   (i) obtain explanations of significant variances with comparative reporting periods;

   (j) review of business systems changes and implications;

   (k) review of authority and approval limits;

   (l) review the adequacy and effectiveness of the accounting and internal control policies of the Corporation and procedures through inquiry and discussions with the external auditors and management;

   (m) confirm through private discussion with the external auditors and the management that no management restrictions are being placed on the scope of the external auditors' work;

   (n) review of tax policy issues; and

(o) review of emerging accounting issues that could have an impact on the Corporation.

5. It is the responsibility Audit Committee to review the interim financial statements of the Corporation and, if deemed appropriate, to recommend the financial statements to the Board for approval and to review all related management discussion and analysis. The Audit Committee must be satisfied that adequate procedures are in place for the review of the Corporation's disclosure of all other financial information and shall periodically assess the accuracy of those procedures.

6. The Audit Committee shall have the authority to:

(a) inspect any and all of the books and records of the Corporation, its subsidiaries and affiliates;

(b) discuss with the management and senior staff of the Corporation, its subsidiaries and affiliates, any affected party and the external auditors, such accounts, records and other matters as any member of the Audit Committee considers necessary and appropriate;

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

(d) to set and pay the compensation for any advisors employed by the Audit Committee.

7. With respect to the appointment of external auditors by the Board, the Audit Committee shall:

(a) recommend to the Board the appointment of the external auditors;

(b) review the performance of the external auditors and make recommendations to the Board regarding the replacement or termination of the external auditors when circumstances warrant;

(c) oversee the independence of the external auditors by, among other things, requiring the external auditors to deliver to the Audit Committee, on a periodic basis, a formal written statement delineating all relationships between the external auditors and the Corporation and its subsidiaries;

(d) recommend to the Board the terms of engagement of the external auditor, including the compensation of the auditors and a confirmation that the external auditors shall report directly to the Committee; and

(e) 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.

8. Audit Committee shall review annually with the external auditors their plan for their audit and, upon completion of the audit, their reports upon the financial statements of the Corporation and its subsidiaries.

9. The Audit Committee must pre-approve all non-audit services to be provided to the Corporation or its subsidiaries by external auditors. The Audit Committee may delegate, to one or more members, the authority to pre-approve non-audit services, provided that the member report to the Audit Committee at the next scheduled meeting and such pre-approval and the member comply with such other procedures as may be established by the Audit Committee form time to time.

10. The Audit Committee shall review the risk management policies and procedures of the Corporation (i.e. hedging, litigation and insurance), including the annual review of insurance coverage and make appropriate recommendations to the Board with respect thereto.

11. The Audit Committee shall establish and maintain procedures for:

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

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

12. The Audit Committee shall review and approve the Corporation's hiring policies regarding employees and former employees of the present and former external auditors or auditing matters.

13. The Audit Committee shall periodically report the results of reviews undertaken and any associated recommendations to the Board.

14. The Audit Committee shall assess, on an annual basis, the adequacy of this Mandate and the performance of the Audit Committee.