TERRACE ENERGY CORP.
(the "Company" or "Terrace")
MANAGEMENT'S DISCUSSION AND ANALYSIS
OF THE COMPANY'S FINANCIAL CONDITION AND RESULTS OF OPERATIONS
FOR THE NINE AND THREE MONTHS ENDED OCTOBER 31, 2014 AND 2013

Introduction

The following management discussion and analysis of the financial condition and results of operations ("MD&A") of the Company has been prepared by management, in accordance with the requirements of National Instrument 51-102 as of December 30, 2014 and should be read in conjunction with the unaudited condensed consolidated interim financial statements for the nine and three months ended October 31, 2014 and 2013 and the related notes contained therein, which have been prepared under International Financial Reporting Standards ("IFRS"), the audited consolidated financial statements and the related MD&A for the years ended January 31, 2014 and 2013, and all other disclosure documents of the Company. The information contained herein is not a substitute for detailed investigation or analysis on any particular issue and is not intended to be a comprehensive review of all matters and developments concerning the Company. Additional information relevant to the Company's activities including the appraisal report on proved and probable reserves can be found on SEDAR at www.sedar.com and the Company's website at www.terraceenergy.net.

All financial information in this report has been prepared in accordance with IFRS and all monetary amounts referred to herein, are in United States dollars, unless otherwise stated.

Caution Regarding Use of Barrels of Oil Equivalent (BOEs)

BOEs/boes may be misleading, particularly if used in isolation. A BOE conversion ratio of six (6) Mcf to one (1) bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. As the value ratio between natural gas and crude oil based on the current prices of natural gas and crude oil is significantly different from the energy equivalency of 6:1, utilizing a conversion on a 6:1 basis may be misleading as an indication of value.

Cautionary Statement Regarding Forward Looking Statements

This discussion and analysis and the documents referenced in this discussion and analysis contain forward-looking information which include, but is not limited to, statements with respect to future activities of the Company, the Company's plans for its oil and gas properties, including partnership and funding arrangements at Maverick County and Big Wells, the future financial or operating performance of the Company, its subsidiaries and its projects, the timing and amount of estimated future capital required, operating and capital expenditures, costs and timing of future exploration, government regulation of oil and gas operations, environmental risks, reclamation expenses, title disputes or claims, limitations of insurance coverage, the timing and possible outcome of pending litigation and regulatory matters. These statements relate to analyses and other information that are based on forecasts of future results, estimates of amounts not yet determinable and assumptions of management. In addition, the exploration and development of oil and gas properties involves certain significant risks, not within the control of management, which can adversely impact the Company's plans and expectations (see "Risk factors"). Readers are cautioned not to place undue reliance upon these forward looking statements.

Cautionary Note to United States Investors

This discussion and analysis and the Company's unaudited condensed consolidated interim financial statements are prepared and presented in accordance with the rules and regulations that govern Canadian reporting issuers, as required by the TSX Venture Exchange (the "Exchange") and applicable securities laws in Canada. The Company does not report to the United States Securities and Exchange Commission, and, in its public disclosure, it may use terms which are not permitted terminology in the United States. In addition, United States investors are cautioned that the Company's condensed consolidated interim financial statements do not conform with, nor are they reconciled to, accounting principles generally accepted in the United States.

Overview

Terrace Energy Corp. (the "Company" or "Terrace") was incorporated on July 6, 2006 under the Business Corporations Act (British Columbia) and previously named Terrace Resources Inc.

The Company is in the business of acquiring, exploring and developing unconventional onshore oil and gas properties in the United States. The Company has a limited history of revenues and operating cash flows. The continuing operations of the Company are therefore dependent upon its future profitable operations and its ability to raise additional capital as required, neither of which is assured.

The Company's head office is located at Suite 1012-1030 West Georgia Street, Vancouver, British Columbia V6E 2Y3. It's registered and records office is located at 10th Floor, 595 Howe Street, Vancouver, British Columbia V6C 2T5. The Company also maintains its principal office at Suite 400, 202 Travis Street, Houston, Texas 77002 where all its operating activities are managed.

The Company's common shares trade on the Exchange under the symbol "TZR", on the OTCQX in the United States under "TCRRF" and on the Frankfurt Exchange under "2TR".

The following table lists the Company's principal operating subsidiaries, their jurisdiction of incorporation and its percentage ownership of their voting securities as of the date of this report:

Name of subsidiary	Place of Incorporation	Percentage ownership
Terrace US Holdings LLC	USA	100%
Terrace Operating, LLC	USA	100%
Terrace Cutlass, LLC	USA	100%
Terrace STS, LLC	USA	100%
TEC Operating, LLC	USA	100%
Terrace BWP, LLC	USA	100%
Terrace Investment Holdings Inc.	USA	100%

See "Exploration and Evaluation Assets" for the Company' interest in BlackBrush Terrace LP.

Exploration and Development Assets

The following is a brief description of the Company's principal assets:

STS Olmos

In November 2011, the Company entered into an agreement, through a wholly-owned subsidiary, to acquire varying working and net revenue interests, which average approximately 27% and 20.25%, respectively, in approximately 14,400 gross mineral acres (3,875 net mineral acres) in LaSalle and McMullen Counties, Texas and an evaluation well.

The Company has secured its working and net revenue interests in this acreage subject to participation in the development of additional wells proposed from time to time by the project's operator.

To date, the Company has participated in the reentry and horizontal extension of the evaluation well and the drilling of fourteen additional development wells, all of which were drilled horizontally with lateral lengths averaging approximately 4,500 feet. Eleven of these wells have been successfully completed in the Olmos tight sandstone formation using multi-hydraulic fracturing techniques. The remaining three wells are expected to be completed in early 2015. The Company's share of the aggregate costs to drill, complete and place into production these wells through October 31, 2014 was $18,765,989.

The cumulative revenues from the net sale of hydrocarbon production from these wells from their completion dates to October 31, 2014 was $13,048,335 and was derived from the sale of 114,303 barrels of oil, 243,765 thousand cubic feet of gas and 1,889,330 gallons of natural gas liquids, which is the equivalent of 199,915 BOEs in the aggregate

One additional well in which the Company did not have a working interest was also drilled and successfully completed on the project acreage by the project's operator. This well provided valuable technical data.

The first eight wells, which were completed as part of a delineation program, adequately defined the project's reservoir potential and allowed the Company to secure a $75 million senior unsecured term credit facility from Chambers Energy Capital to fund its future development.

The Company and its partner initiated a "pad drilling" development program in August, 2014. Drilling operations were subsequently completed on the first three-well pad, the Section 6 pad in McMullen County. All three wells successfully encountered the target zones. Fracing operations have been completed and flowback operations will commence in January 2015. Drilling operations are also completed on the second three-well pad, the Section 5 pad in LaSalle County. All three of these wells also successfully encountered the target zones. Drilling operations commenced on a third pad location during December 2014. Fracing operations on the Section 5 pad will commence in early 2015, pending equipment availability.

The Company plans to maintain a single rig program for 2015 and continue to drill three-well pads in order to optimize the cycle from capital outlay to production. Based on this development strategy and current prices, capital expenditures for the project in 2015 are expected to be approximately $25 million, of which approximately one-half will be drawn from the credit facility and one-half from net operating cash flows and other available liquidity. It is important to note that the Company's predictive models are conservatively based on risk-weighted type curves generated from approximately 75% of the observed performance of the initial eight delineation wells previously put into production. The current drilling program incorporates significantly longer laterals and an enhanced frac design, which are expected to materially improve well performance and reserve recovery.

In October 2013, the Company entered into agreements, through a wholly-owned subsidiary, to earn a 100% working interest and a 75% net revenue interest in the "Olmos" formation within an additional 1,230 net mineral acres adjacent to the Company’s existing leasehold interest. The Company made an initial payment of $492,148 to secure the right to earn-in. The Company subsequently learned of certain title deficiencies, which have yet to be resolved. Although the Company is exploring possible curative actions to correct the deficiencies, it is unlikely that these actions will be successful and accordingly a charge in the amount of the initial payment has been recorded to impairment expense in the current period.

Northwest AWP Project

The Northwest AWP Project is located in the nearby vicinity to the Corporation's STS Olmos Project and possesses similar geological characteristics. In January, 2014, the Corporation entered into agreements, through a wholly-owned subsidiary, to earn a 33.34% working interest and a 24.59% net revenue interest in certain leases covering approximately 199 gross mineral acres in McMullen County, Texas as well as an option to acquire a 33.34% working interest and a 24.59% net revenue interest in adjacent leases covering an additional 3,618 gross mineral acres. The interests to be acquired in this project are depth limited to the Olmos tight Sandstone formation.

The purchase consideration consisted of a payment of $33,173, which has been paid, and a commitment to participate in the drilling of an “Evaluation Well”.

On August 3, 2014 the Company spud the Evaluation Well, the Quintanilla OL 1-H well. The Evaluation Well was successfully completed during the period and is currently producing. During the initial 60 days of production, the well produced 18,592 barrels of oil and 19,040 mcf of gas. The well was recently producing at a rate of 388 bopd, 456 mcfd (464 boepd) on a 13/64ths choke.

The Company has a 90 day option which expires in January 2015 to acquire the 33.34% working interest and a 24.59% net revenue interest in approximately 3,618 gross mineral acres (1,206 net mineral acres) for an additional payment of approximately $686,454. It is estimated that the option acreage will contain approximately fifteen additional prospective drilling locations. The Company expects to exercise its option to acquire the offset acreage and drill up to a total of four development wells in 2015. The mineral leases in this project are held by other production at deeper horizons. Thus, the Company and its partners have flexibility to manage the timing of development drilling without external leasehold obligation pressures.

Investment in BlackBrush Terrace LP (Maverick County Project)

The Company and its partner, BlackBrush Oil & Gas, LP (“BlackBrush”) organized a special purpose limited partnership, the BlackBrush Terrace LP (the “SPLP”), to acquire a 50% working interest (the “WI”) in certain oil and gas leases covering approximately 147,000 gross mineral acres in Maverick County Texas, USA (the “Maverick County Project”) from SWEPI LP (“Shell Oil”). The acreage to be acquired includes potential reserves in the newly emerging Pearsall Shale Trend as well as the Eagle Ford Shale, Buda Limestone and several other intervals of Cretaceous age formations which have been proven productive on a regional basis. The SPLP may secure the WI through a combination of cash payments, which have been made, and drilling obligations. The material terms of the agreement between the SPLP and Shell Oil are as follows:

1. the SPLP has the option, but not the obligation, to earn the assignment of the WI in all of the leases by spending an aggregate of $104 million ($52 million net to Terrace), including $52 million ($26 million net to Terrace) representing Shell Oil’s share of costs, (the “Carry Payment”) on certain qualified expenditures as development of the property progresses over time;

2. upon completion of a well drilled under this agreement, the SPLP may request an assignment of 50% of Shell Oil's interest in such well;

3. upon making the Carry Payment in full, the SPLP shall have the option, but not the obligation, to pay 50% of all development costs for the right to participate in at least a 50% working interest in each subsequent well by paying its proportionate share of all development costs for such well unless Shell Oil elects to convert its working interest in a producing formation into a net profits interest; and

4. Shell Oil has the right, but not the obligation to assume operatorship of any formation in which production has been established at any time within two years after the later of (i) the Carry Payment being made in full and subsequent assignment of 50% of Shell Oil's interest in the subject leases or (ii) establishment of commercial production from a given formation.

During this quarter, the SPLP has successfully renegotiated the drilling obligations under the farmout agreement predominantly to amend the required targets and timing of future wells necessary to fulfill the remaining earning requirements. Under the revised agreement, the SPLP now has the flexibility to choose locations, set objectives and govern timing of operations under a blanket requirement to spend $25 million per year ($12.5 million net to Terrace) commencing at 1/1/2015 until the total required drilling carry of $104 million has been spent. Prior to 1/31/2015, the SPLP has spent approximately $32 million towards this obligation. The SPLP is obligated to pay liquidated damages equal to $2 million ($1 million net to Terrace) in the event that the minimum expenditure is not met in any given year.

The SPLP successfully drilled its first well, the Chittim #1-H, as a Pearsall Shale evaluation well. The well was spudded on April 1, 2013 and drilled to a total depth of 11,620 feet including a horizontal section of approximately 4,700 feet within the Pearsall Shale with positive hydrocarbon indicators throughout the drilling process. During the drilling operations, extensive petrophysical testing was also conducted on several potentially productive strata within the Cretaceous age formations above the Pearsall Shale with positive hydrocarbon indicators in multiple formations including the Eagle Ford Shale and Buda Limestone. The results of these analyses are currently under review with Shell for planning further evaluation drilling in these shallower intervals.

During 2013, the SPLP successfully tested the Eagle Ford formation through the re-entry of the SWEPI Chittim #F-1H, which was previously drilled and shut in by Shell Oil in 2011 and the drilling of a second well to test the Eagle Ford and Buda Limestone Formations. The Chittim Heirs #2H was spud on October 4, 2013 and drilled to a vertical depth of 5,300 feet in order to gather petrophysical testing data including core samples through the objective formations. The well was subsequently plugged back to approximately 4,850 feet and a 4,100 foot horizontal lateral was drilled in the Eagle Ford Shale. The well was successfully completed utilizing a multi-stage hydraulic stimulation treatment utilizing a hydrocarbon-based, rather than water-based fracturing fluid. Both of these wells have been placed on artificial lift and are currently producing at a rate of approximately 20 BOEPD each. Initial production rates are not necessarily indicative of long-term performance or of ultimate recovery.

In 2014, BTLP drilled four critical evaluation wells including two horizontal wells to evaluate the Buda Limestone potential on the southern portion of the ranch and two vertical stratigraphic tests to evaluate several formations from Austin Chalk through Georgetown in a portion of the ranch penetrated by a large serpentine plug (volcanic feature). The results of the drilling phase of each of these wells are encouraging. Data collected from these wells are currently under evaluation and completion strategies are being developed. Completions for each of these wells will be included in the 2015 drilling obligation budget.

During the nine months ended October 31, 2014, the Company's recognized share of the SPLP's net loss was $138,679. The Company's share of production from the partnership for the nine month period ended October 31, 2014 was 1,352 BOE.

Up to October 31, 2014, the Company advanced the aggregate sum of $18,524,848 representing its share of costs to organize, acquire and fund exploration and evaluation activities to-date.

Further capital expenditures on the project are not required until mid-2015. By design, the BTLP partnership agreement allows for adjusting the ownership interests of the limited partnership by introducing third party investors into the partnership and/or allowing either partner to disproportionately fund future capital requirements. In light of the current economic environment, the Company has begun meeting with prospective investors to discuss funding of Terrace's share of capital obligations for 2015. If these discussions result in favourable agreements, the Company's partnership interest will be reduced and its current obligations carried.

Big Wells Project

In February, 2014, the Corporation entered into agreements, through a wholly-owned subsidiary, to earn a 75% working interest and a 56.25% net revenue interest in certain leases covering approximately 10,130 gross mineral acres in Dimmit and Zavala Counties, Texas. The interests to be acquired in this project are depth limited to the Buda Limestone formation.

Under the terms of the agreements, the Corporation has the option to drill a series of "Earning Wells", each of which will secure the Corporation's interest in a 640 gross mineral acre tract. The Corporation will be required to pay 100% of the capital costs of each Earning Well and will receive 100% of the gross revenues from such Earning Well until it has recovered its capital investment. Upon capital recovery, the farmor will be offered an election to accept a 25% working interest and 18.75% net revenue interest in the Earning Well or exchange its rights for a 5% overriding royalty interest. Depending on the farmor's election, the Corporation will secure either a 75% working interest / 56.25% net revenue interest or a 100% working interest / 70% net revenue interest in each earned 640 acre tract.

The Company recently completed the Earning Well, the Price #1H well, which validated the geologic concept for this project and established the presence of commercially producible hydrocarbons. Testing is underway and results will be announced in due course as they are evaluated. Subsequent Earning Wells must be spud no more than 120 days after the agreed upon completion date of the previous Earning Well in order for the Corporation to continue earning acreage under these agreements. Once a 640 acre tract is earned, the Corporation will continue to hold that acreage under customary leasehold terms regarding on-going production and / or subsequent operations. There is no penalty for non-performance other than the loss of opportunity to continue earning additional acreage.

In order to maintain its rights under the farmout agreement, the Company will be required to drill three additional wells on the project acreage at a gross cost of approximately $12 million. The Company is in discussions with several industry participants to sell a 50% interest in the project in order to fund most or all of its 2015 capital commitments. If successful, we would expect that any remaining capital requirements would be paid from project cash flow. There are, however, no assurances the Company will secure a capital partner on terms acceptable to the Company or on any terms.

This strategy is entirely consistent with the Company's overall business model of acquiring projects and establishing value at a high working interest, then inviting capital providers in at the project level. The Company always expected to reduce its interest to a 50% working interest in this project as it moves towards delineation and development.

Cutlass

In November, 2011 and February, 2012, the Company entered into agreements, through a wholly-owned subsidiary to earn a 30% working interest and a 22.5% net revenue interest in certain leases covering 3,395 gross mineral acres in Dimmit and LaSalle counties.

During the fiscal year ended January 31, 2014, the Company funded all of the costs necessary to earn its working interests in the properties that comprise the Cutlass project. The appropriate assignments of working interest have been received by the Company for each of the leases and have been filed on record in the Counties of LaSalle and Dimmitt, TX.

Upon completing a project review in October 2013, management determined that Cutlass was no longer a core asset and decided to solicit bids from prospective purchasers. A data room was been established and the Company continues to entertain purchase offers and other proposals for development of these leases.

The Company previously determined that the proposed sale met the definition of "assets held for sale", under IFRS 5 Non-current Assets Held for Sale and Discontinued Operations, and therefore reclassified the various assets and liabilities associated with the Company's interests in Cutlass to "assets held for sale" and "liabilities associated with assets held for sale".

Although it is still the intent of the Company to sell its interest in Cutlass, IFRS 5 prescribes that "assets held for sale" must be sold within twelve month or reclassified. The Company was unable to sell Cutlass by October 31, 2014 and therefore reclassified the assets back to the appropriate balance sheet classifications.

During the twelve month period ended October 31, 2014, during which the Cutlass assets were classified as assets held for sale, the project generated operating income of $573,475, comprising revenues and expenses of $1,231,056 and $657,581, respectively. As a result of the reclassifications, the Company recorded additional depletion expense of $1,372,906 to reflect the depletion that would have been recorded had the Cutlass assets not been classified as assets held for sale. In addition, Management evaluated the Cutlass assets before reclassification, based on recent expressions of interest from potential acquirers, and remeasured them at $7,794,324, resulting in an impairment charge during the period of $1,608,623.

In August, 2014, the project operator made a spurious claim that the Company did not meet its obligations and demanded it reassign its interests in the leases. The Company considers this claim to be without merit and has taken appropriate legal action in LaSalle County, TX to establish clear ownership of its title to these leases. Until such matter is resolved, the Company expects to experience difficulty in successfully marketing the sale of its interest in the Cutlass Project.

Seismic Data Acquisition

In June, 2014, the Company acquired a non-exclusive license to 3-D seismic data for $1.1 million. This data covers the southern portion of the farmout acreage in the Big Wells Project and is a critical analytical tool used for optimizing drilling locations on the project. In August, 2014, the Company expanded this purchase to include additional data covering the remainder of the farmout acreage in the Big Wells Project. The company paid an additional license fee of $1.2 million for this data set.

The additional data is part of a multi-year commitment to purchase multiple data sets at a volume discounted rate. The additional data is to be selected at the Company's discretion to aid in the evaluation of the expansion of its existing projects (including offsetting acreage surrounding its STS Olmos Development Project) and/or new projects developed over the next two years. Under the current agreement, the Company is committed to purchase additional data in each of 2015 and 2016 at a cost of $2,362,500 per year; however, the Company is currently reassessing its development plans, timing and data requirements in light of the current commodity price environment. Consequently, the Company has initiated discussions to restructure this agreement. There can be no assurances that these discussions will result in modifying the existing commitments.

Results of Operations

For the nine months ended October 31, 2014 and 2013

Net loss for the nine months ended October 31, 2014 was $6,848,823 compared to net loss of $4,451,037 for the nine months ended October 31, 2013. The results are summarized as follows:

	2014	2013
Oil and gas revenues	$ 5,286,246	$ 2,869,536
Direct operating expenses	1,490,255	331,978
Depreciation, depletion and accretion	3,259,393	1,159,040
Operating income	536,598	1,378,518
Equity income (loss) in partnership	(138,679)	137,662
	397,919	1,516,180
General and administrative expenses	2,760,585	2,319,886
Interest expense	3,358,197	1,959,514
Foreign exchange (gain) loss	(1,083,466)	(197,017)
Share-based payments	129,131	368,654
Impairments	2,082,295	-
	7,246,742	4,451,037
Net loss for the period	$ (6,848,823)	$ (2,934,857)

Oil and gas sales for the nine months ended October 31, 2014 were $5,559,828 less royalties of $273,582 compared to $3,012,296 less royalties of $142,760 for the nine months ended October 31, 2013.

The Company's aggregate share of sales from these wells for the nine months ended October 31, 2014 was approximately 69,904 barrels of oil and liquids at an aggregate average price of $68.68 per barrel of oil equivalent and 169,089 thousand cubic feet of natural gas at an average price of $4.49 per thousand cubic feet as compared to the previous period of approximately 50,514 barrels of oil and liquids at an average price of $80.96 per barrel of oil equivalent and 70,534 thousand cubic feet of natural gas at an average price $2.92 per thousand cubic feet.

*Direct operating expense*s for the nine months ended October 31, 2014 were $1,490,255 compared to $331,978 for the nine months ended October 31, 2013. The increase is due primarily to the increase in producing wells. During the nine months ended October 31, 2014 we had 12 wells producing, whereas during the nine months ended October 31, 2013 we had 7 wells producing of which most began producing late in the nine month period. Operating income net of depreciation, depletion and accretion expenses of $3,259,393 was $536,598 for the nine months ended October 31, 2014 and operating income net of depreciation, depletion and accretion expenses of $1,159,040 was $1,378,518 for the same period in 2013. The increase in depreciation, depletion and accretion expenses was due to the increase in production noted above and due to a catch-up depletion charge related to Cutlass. The company recorded depletion expense of $1,309,818 during the period as a result of Cutlass being reclassified out of assets held for sale. The charge is to reflect the depletion that would have been previously recorded in each quarter from November 2013 to October 2014 had the Cutlass property not been classified as assets held for sale during that period.

General and Administrative expenses for the nine months ended October 31, 2014 were $2,760,585 compared to $2,319,886 for the nine months ended October 31, 2013. These expenses are comprised primarily of office costs, including rent, executive and other salaries, professional fees for legal and audit services, transfer agent and Exchange fees and investor relations activities. The increase is due mainly to an increase in salaries and benefits that increased by $580,935 to $1,225,752 as result of a doubling of the number of employees during the comparative periods.

Interest expense for the nine months ended October 31, 2014 were $3,358,197 compared to $1,959,514 for the nine months ended October 31, 2013 which is primarily attributable to the convertible notes the Company issued. Interest expense includes a non-cash expense of $500,450 which represents accretion of the convertible notes during the period compared to $390,240 for the nine months ended October 31, 2013, Additionally, during the period ended October 31, 2014 the company entered into a credit facility for the development of our STS Olmos project resulting in interest of $752,411 of which $285,478 was a non-cash expense as it accrues to the outstanding principal of the facility.

Foreign exchange gain for nine months ended October 31, 2014 was $1,083,466 compared to a gain of $197,017 for the nine months ended October 31, 2013. The change in foreign exchange was due to fluctuations in the USD exchange rate during the period.

Share-based payments for the nine months ended October 31, 2014 were $129,131 compared to $368,654 for the nine months ended October 31, 2013 due to the timing of granting stock options and their related vesting periods during the current period compared to the prior period.

Impairment for the nine months ended October 31, 2014 was a charge of $2,082,295 compared to $Nil for the nine months ended October 31, 2013. During the current period the company recognized an impairment of $1,590,158 to adjust the carrying value of the Cutlass properties to their fair value less costs to sell the properties. In addition, the company recorded a charge of $492,137 to reflect the impairment in value on acquired acreage at our STS project which we discovered to have certain title deficiencies which we have determined are unlikely to be cured.

For the three months ended October 31, 2014 and 2013

Net loss for the three months ended October 31, 2014 was $5,197,456 compared to net loss of $1,898,461 for the three months ended October 31, 2013. The results are summarized as follows:

	2014	2013
Oil and gas revenues	$ 1,240,376	$ 1,321,384
Direct operating expenses	530,849	82,664
Depreciation, depletion and accretion	1,847,423	665,509
Operating income (loss)	(1,137,896)	573,211
Equity income in partnership	(52,776)	101,753
	(1,190,672)	674,964
General and administrative expenses	988,956	1,018,542
Interest expense	1,590,555	926,389
Foreign exchange (gain) loss	(702,667)	564,034
Share-based payments	29,180	64,460
Impairments	2,100,760	-
	4,006,784	2,573,425
Net loss for the period	$ (5,197,456)	$ (1,898,461)

Oil and gas sales for the three months ended October 31, 2014 were $1,298,753 less royalties of $58,377 compared to $1,390,636 less royalties of $69,252 for the three months ended October 31, 2013.

The Company's aggregate share of sales from these wells for the three months ended October 31, 2014 was approximately 16,379 barrels of oil and liquids at an aggregate average price of $67.55 per barrel of oil equivalent and 47,760 thousand cubic feet of natural gas at an average price of $4.03 per thousand cubic feet as compared to the previous period of approximately 31,477 barrels of oil and liquids at an average price of $93.05 per barrel of oil equivalent and 46,082 thousand cubic feet of natural gas at an average price $2.72 per thousand cubic feet.

Direct operating expenses for the three months ended October 31, 2014 were $530,849 compared to $82,664 for the three months ended October 31, 2013. The increase is due primarily to the increase in producing wells. During the three months ended October 31, 2014 we had twelve wells producing, whereas during the three months ended October 31, 2013 we had seven wells producing of which five came on production at various points during the quarter. Operating income net of depreciation, depletion and accretion expenses of $1,847,423 was $(1,137,896) for the three months ended October 31, 2014 and operating income net of depreciation, depletion and accretion expenses of $665,509 was $573,211 for the same period in 2013. The increase in depreciation, depletion and accretion expenses was primarily due to a catch-up depletion charge related to Cutlass. The company recorded depletion expense of $1,309,818 during the period as a result of Cutlass being reclassified out of assets held for sale. The charge is to reflect the depletion that would have been previously recorded in each quarter from November 2013 to October 2014 had the Cutlass property not been classified as assets held for sale during that period.

General and Administrative expenses for the three months ended October 31, 2014 were $988,956 compared to $1,018,542 for the three months ended October 31, 2013. These expenses are comprised primarily of office costs, including rent, executive and other salaries, professional fees for legal and audit services, transfer agent and Exchange fees and investor relations activities. The decrease was primarily a result of a decrease in administrative and professional expenses of $320,436 partially offset by an increase in salaries and benefits expense of $233,475 to $473,683 as result of a doubling of the number of employees during the comparative periods.

Interest expense for the three months ended October 31, 2014 were $1,590,555 compared to $926,389 for the three months ended October 31, 2013 which is primarily attributable to the convertible notes the Company issued. Interest expense includes a non-cash expense of $159,832 compared to $179,669 for the three months ended October 31, 2013, which represents accretion of the convertible notes during the period. Additionally, during the period ended October 31, 2014 the company entered into a credit facility for the development of our STS Olmos project in June 2014 which was funded in September 2014 resulting in interest during the period of $752,411 of which $285,478 was a non-cash expense as it accrues to the outstanding principal of the facility.

Foreign exchange gain for the three months ended October 31, 2014 was $702,667 compared to a loss of $564,034 for the three months ended October 31, 2013. The change in foreign exchange was due to fluctuations in the USD exchange rate during the period.

Share-based payments for the three months ended October 31, 2014 were $29,180 compared to $64,460 for the three months ended October 31, 2013 due to the timing of granting stock options and their related vesting periods during the current period compared to the prior period.

Impairment for the three months ended October 31, 2014 was a charge of $2,100,760 compared to $Nil for the three months ended October 31, 2013. During the current period the company recognized an impairment of $1,608,623 to adjust the carrying value of the Cutlass properties to their fair value less costs to sell the properties. In addition, the Company recorded a charge of $492,137 to reflect the impairment in value on acquired acreage at our STS project which we discovered to have certain title deficiencies which we have determined are unlikely to be cured.

Summary of Quarterly Results

The results of the Company's most recent eight quarters are set out below:

	October 31, 2014	July 31, 2014	April 30, 2014	January 31, 2014
Revenue (net of royalties)[1]	$ 1,240,376	$ 1,503,040	$ 2,542,830	$ 2,849,277
Net loss	(5,197,456)[2]	(1,422,583)[3]	(228,784)[4]	(3,640,635)[5]
Exploration and evaluation[9]	14,831,197	2,431,915	1,231,887	1,231,887
Property and equipment[9]	18,649,028	14,479,455	13,376,836	13,665,655
Assets held for sale[11]	-	9,658,593	10,000,000	10,000,000
Investment in partnership[10]	18,438,222	16,667,631	16,618,348	15,681,920
Total assets	89,092,271	74,602,228	54,245,695	53,863,687
Loss per share – basic and diluted	(0.06)	(0.02)	(0.00)	(0.05)

	October 31, 2013	July 31, 2013	April 30, 2013	January 31, 2013
Revenue (net of royalties)[1]	$ 1,321,384	$ 732,021	$ 816,131	$ 2,206,194
Net income (loss)	(1,898,461)[6]	(498,568)[7]	(537,828)[8]	106,951[9]
Exploration and evaluation[10]	1,754,179	10,878,981	8,757,149	6,737,039
Property and equipment[10]	13,786,749	9,615,819	5,810,585	6,047,528
Assets held for sale[12]	15,073,427	-	-	-
Investment in partnership[11]	13,761,728	12,900,434	12,915,830	-
Total assets	52,398,640	53,026,973	39,699,459	16,319,564
Income (loss) per share – basic and diluted	(0.03)	(0.01)	(0.01)	0.00

Notes:

1) Revenue is primarily a result of oil and gas sales less royalties which varies each period depending on the number of wells in production.
2) Net loss during this period includes non-cash deductions of $29,180 for share–based payments, $1,847,423 for depletion and accretion expenses.
3) Net loss during this period includes non-cash deductions of $41,219 for share–based payments, $606,883 for depletion and accretion expenses.
4) Net loss during this period includes non-cash deductions of $58,732 for share–based payments, $805,087 for depletion and accretion expenses.
5) Net loss during this period includes non-cash deductions of $57,639 for share–based payments, $807,462 for depletion and accretion expenses, and $3,747,259 for impairment of assets held for sale.
6) Net loss during this period includes non-cash deductions of $64,460 for share–based payments, $665,509 for depletion and accretion expenses.
7) Net loss during this period includes non-cash deductions of $231,077 for share–based payments, $220,773 for depletion and accretion expenses.
8) Net income during this period includes non-cash deductions of $142,042 for share–based payments, $799,961 for depletion and accretion expenses.
9) Net loss during this period includes non-cash deductions of $104,787 for share–based payments and $24,955 for depletion and accretion expenses.
10) The fluctuations between Exploration and Evaluation and Property and Equipment are due to the transfers of the Company's share of the costs to drill, evaluate and case the wells related to the STS Olmos project and the Cutlass project.
11) The Company entered into an agreement with BlackBrush Oil and Gas, LP. The carrying value represents the Company's share of costs to organize, acquire and fund certain agreed upon exploration and evaluation activities to-date plus the Company's share of the changes in net assets of the partnership.
12) As of October 31, 2013 the Company reclassified costs associated with Cutlass to assets held for sale. At October 31, 2014 the Company reclassified costs associated with Cutlass out of assets held for sale due to the twelve month rule in IFRS 5.

Fluctuations in reported earnings during the prior quarters are primarily due to changes in oil and gas production, depletion and revenues, asset impairment charges, share-based payments, foreign exchange adjustments and professional fees. The time during which the Company acquires, develops, disposes or abandons projects materially impacts the results of operations from fiscal quarter to quarter.

Financial Condition, Liquidity and Capital Resources

As at October 31, 2014, the Company had working capital of $35,017,569 (January 31, 2014 - $22,052,555), which is substantially comprised of cash of $34,823,565, accounts receivable of $919,947 less current liabilities of $948,970 due within three months of October 31, 2014.

On June 6, 2014, a wholly-owned subsidiary of the Company entered into a senior unsecured term credit facility (the "Credit Facility"), which is non-recourse to Terrace, to fund the development of its STS Olmos Project in McMullen and LaSalle counties in south Texas. The aggregate amount of the Credit Facility is $75.0 million, of which $50 million may be drawn at the Company's discretion. The remaining $25 million will be made, at the Lender's discretion, depending upon project performance and market conditions. The term of the facility is four years with cash interest of LIBOR (with a floor of 1%) plus 7% plus payment in kind ("PIK") interest of 5% per annum. Cash interest to be paid monthly; principal and PIK interest paid upon maturity. Prepayment is permitted under certain conditions.

During the period, the Company made an initial draw of $25 million and received net proceeds of $24 million after deducting the agreed upon issue discount of $1 million. The Company also incurred $1.4 million of legal and other additional costs of which approximately one-half has been capitalized as deferred financing costs and one-half has been netted against the balance outstanding under the facility and will be amortized into interest expense over the life of the facility.

It is Management's intention to dispose of the Cutlass oil and gas assets previously classified as held for resale in due course and use the proceeds from the sale to further develop the Company's core assets.

As at October 31, 2014 and the date of this report, the Company had outstanding long term convertible notes in the principal amount of CAD $38,590,000 (January 31, 2014 – CAD $38,825,000), which are due on April 2, 2018. These notes bear interest calculated at 8% per annum, which is payable quarterly, and may become immediately due in the event of default. A more detailed description of the notes is set out in Note 10 to the Company's condensed consolidated interim financial statements for the nine and three months ended October 31, 2014.

Year to date October 31, 2014, the company issued 12,443,000 common shares for gross proceeds of CAD $23,019,550 at a price of CAD $1.85 per share via a short form prospectus. Share issue costs of CAD $1,774,407, which include $1,496,271 of agents' fees, were paid in connection with the public offering.

Year to date October 31, 2014, the Company issued 117,500 common shares on conversion of CAD $235,000 convertible notes

The Company's working capital will be used to fund the development of the Company's oil and gas properties (see commitments described under "Exploration and Evaluation") and for general working capital purposes.

As of the date of this report, the Company has no significant commitments except as described herein (see "Exploration and Evaluation") and in footnote 15 of the Company's condensed consolidated interim financial statements for the nine and three months ended October 31, 2014. The Company has not pledged any of its assets as security for loans.

The Company is restricted from utilizing funds drawn under the Credit Facility or funds generated from the operations of its STS Olmos Project for anything other than for operating costs and ongoing development activities at the STS Olmos Project. The terms of the Credit Facility also provides for certain other covenants including the requirement to maintain certain financial condition covenants. The financial condition covenants consist of the quarter end requirement to maintain an asset coverage ratio of 1.25 to 1, to maintain a current ratio of 1:1 and a leverage ratio which limits the amount of debt outstanding relative to EBITDA ranging from 2 to 1 up to 3.25 to 1 depending on the period. As at October 31, 2014 the Company is not in breach of any of these covenants.

Management of the Company believes with existing liquidity, cash generated from operations, the sale of assets held for resale and obtaining carry commitments for future drilling obligations that the Company will have sufficient capital to meet its existing financial obligations over the next twelve months. However, there is no assurance the Company will generate sufficient sustainable cash flows to fund the future development of its oil and gas properties as presently planned and therefore the Company may have to seek additional financing (see commitments described under "Exploration and Evaluation Assets"). Although the Company has been successful with securing capital in the past, there is no assurance that it will secure necessary capital in the future.

Off Balance Sheet Arrangements

Except as described herein, there are no off-balance sheet arrangements to which the Company is committed.

Key Management Personnel Compensation

Key management personnel include executive officers and directors of the Company. Compensation of the Company's key management personnel is comprised of the following:

	2014	2013
Short-term compensation		
CEO	$ 270,000	$ 310,000
CFO (current and previous)	114,938	18,348
COO	243,750	-
VP Exploration	150,000	-
VP Geosciences	150,000	-
Secretary	53,488	36,483
Share-based payments	131,232	150,468
	$ 1,113,408	$ 515,299

As at October 31, 2014:

(a) accounts receivable include advances to key management personnel totalling $47,562 (January 31, 2014 - $47,562) for expenses incurred by the Company on their behalf;
(b) convertible notes held by key management personnel totalled CAD $3,040,000.

Proposed transactions

There are no proposed transactions that have not been disclosed herein.

New Accounting Pronouncements

All of the new and revised standards described below may be early-adopted:

IFRS 9 Financial Instruments (2009)

IFRS 9 introduces new requirements for classifying and measuring financial assets, as follows:

- Debt instruments meeting both a "business model" test and a "cash flow characteristics" test are measured at amortized cost (the use of fair value is optional in some limited circumstances)

- Investments in equity instruments can be designated as "fair value through other comprehensive income" with only dividends being recognized in profit or loss
- All other instruments (including all derivatives) are measured at fair value with changes recognized in profit or loss
- The concept of "embedded derivatives" does not apply to financial assets within the scope of the standard and the entire instrument must be classified and measured in accordance with the above guidelines.

The IASB has indefinitely postponed the mandatory adoption date of this standard.

IFRS 9 Financial Instruments (2010)

This is a revised version incorporating revised requirements for the classification and measurement of financial liabilities, and carrying over the existing de-recognition requirements from IAS 39 *Financial Instruments: Recognition and Measurement.*

The revised financial liability provisions maintain the existing amortized cost measurement basis for most liabilities. New requirements apply where an entity chooses to measure a liability at fair value through profit or loss; in these cases, the portion of the change in fair value related to changes in the entity's own credit risk is presented in other comprehensive income rather than within profit or loss.

The IASB has indefinitely postponed the mandatory adoption date of this standard.

Recoverable Amount Disclosures for Non-Financial Assets (Amendments to IAS 36)

Amends IAS 36 *Impairment of Assets* to reduce the circumstances in which the recoverable amount of assets or cash-generating units is required to be disclosed, clarify the disclosures required, and to introduce an explicit requirement to disclose the discount rate used in determining impairment (or reversals) where recoverable amount (based on fair value less costs of disposal) is determined using a present value technique.

Applicable to annual periods beginning on or after January 1, 2014.

Critical accounting estimates

The preparation of the condensed consolidated interim financial statements requires management to make judgments, estimates and assumptions that affect the application of accounting policies and reported amounts of assets and liabilities, revenues and expenses. Actual results may differ from these estimates.

Following are the accounting policies subject to such judgments and the key sources of estimation uncertainty that the Company believes could have the most significant impact on the reported results and financial position.

Reserves

The estimate of oil and natural gas reserves is integral to the calculation of the amount of depletion charged to the condensed consolidated interim statements of operations and comprehensive loss and is also a key determinant in assessing whether the carrying value of any of the Company's development and production assets have been impaired. Changes in reported reserves can impact asset carrying values and the decommissioning provision due to changes in expected future cash flows. The Company's reserves are evaluated and reported on by independent reserve engineers at least annually in accordance with Canadian Securities Administrators' National Instrument 51-101 *Standards of Disclosure of Oil and Gas Activities* ("NI 51-101"). Reserve estimation is based on a variety of factors including engineering data, geological and geophysical data, projected future rates of production, commodity pricing and timing of future expenditures, all of which are subject to significant judgment and interpretation.

Carrying value of property and equipment and exploration and evaluation assets

The Company assesses at each reporting date whether there is an indication that an asset or cash-generating unit ("CGU") may be impaired. A CGU is defined as the lowest grouping of assets that generate identifiable cash inflows that are largely independent of cash inflows of other assets or groups of assets. The allocation of assets into CGUs requires significant judgment and interpretation with respect to the way in which management monitors operations. If any indication exists that an asset or CGU may be impaired, the Company estimates the recoverable amount. The recoverable amounts of individual assets and CGUs have been determined based on the higher of value-in-use calculations and fair value less costs to sell. These calculations require the use of estimates and assumptions, such as estimates of proved plus probable reserves, future production rates, oil and natural gas prices, future costs and other relevant assumptions, all of which are subject to change.

A material adjustment to the carrying value of the Company's property and equipment and exploration and evaluation assets could arise as a result of changes to these estimates and assumptions.

Assets held for sale

Judgment is required in determining whether an asset meets the criteria for classification as "assets held for sale" in the consolidated statements of financial position. Criteria considered by management include the existence of and commitment to a plan to dispose of the assets, the expected selling price of the assets, the expected timeframe of the completion of the anticipated sale and the period of time any amounts have been classified within assets held for sale. The Company reviews the criteria for assets held for sale each quarter and reclassifies such assets to or from this balance sheet category as appropriate. In addition, there is a requirement to periodically evaluate and record assets held for sale at the lower of their carrying value and fair value less costs to sell.

Depreciation and depletion

Depletion of oil and gas properties is provided using the unit-of-production method based on production volumes before royalties in relation to total estimated proved reserves as determined annually by independent engineers and internal reserve evaluations on a quarterly basis. Natural gas reserves and production are converted at the energy equivalent of approximately six thousand cubic feet to one barrel of oil.

Accounts receivable

Accounts receivable are recorded at the estimated recoverable amount, which involves the estimate of uncollectible accounts.

Decommissioning obligations

Amounts recorded for decommissioning obligations require the use of management's best estimates of future decommissioning expenditures, expected timing of expenditures and future inflation rates. The estimates are based on internal and third party information and calculations are subject to change over time and may have a material impact on profit and loss or financial position.

Share-based payments

The fair value of share-based payments is subject to the limitations of the Black-Scholes option pricing model that incorporates market data and involves uncertainty in estimates used by management in the assumptions. Because the Black-Scholes option pricing model requires the input of highly subjective assumptions, including the volatility of share prices, changes in subjective input assumptions can materially affect the fair value estimate.

Risk Factors

The exploration and development of oil and gas properties involves certain significant risks not within the control of management. Risks factors affecting the prospects of the Company include, but are not limited to, the following:

Exploration, Development and Production Risks

Oil and natural gas exploration involves a high degree of risk and there is no assurance that expenditures made on future exploration by the Company will result in new discoveries of oil or natural gas in commercial quantities. The Company, through its subsidiaries, has the right to earn working interests in various oil & gas properties described herein. To earn such interests the Company must incur certain specified expenditures to evaluate and complete a number of prospective wells capable of producing oil and gas in paying quantities. No assurance can be given that the Company will be successful in completing wells capable of producing oil and gas. The long-term commercial success of the Company depends on its ability to find, acquire, develop and commercially produce oil and natural gas reserves. Without the continual addition of new reserves, any existing reserves the Company may have at any particular time and the associated production if any there from will decline over time as the reserves are exploited. A future increase in the Company's reserves will depend not only on its ability to explore and develop any properties it may have from time to time, but also on its ability to select and acquire suitable producing properties or prospects. No assurance can be given that the Company will be able to continue to locate satisfactory properties for acquisition or participation. Exploration and development activities may be delayed or adversely affected by factors outside the control of the Company including adverse climatic and geographic conditions, labour disputes, compliance with governmental requirements, shortage or delays in installing and commissioning plant and equipment or import or customs delays. Drilling may involve unprofitable efforts, not only with respect to dry wells, but also with respect to wells, though yielding some oil or gas, are not sufficiently productive to justify commercial development or cover operating and other costs. Oil and natural gas exploration, development and production operations are subject to all the risks and hazards typically associated with such operations, including hazards such as fire, explosion, blowouts, cratering, sour gas releases and spills, each of which could result in substantial damage to oil and natural gas wells, production facilities, other property and the environment or in personal injury.

Additional Funding Requirements

Terrace has limited history of production or profitability and its financial resources may not be sufficient to fund its ongoing activities at all times (see commitments described under "Exploration and Evaluation"). From time to time, the Company will require additional financing to carry out its oil and gas acquisition, exploration and development activities. Failure to obtain such financing on a timely basis could cause the Company to forfeit its interest in certain properties, miss certain acquisition opportunities and reduce or terminate its operations. Any additional financing is likely to involve the issuance of securities which could be substantially dilutive.

No Assurance of Title

Title to oil and gas interests is often not capable of conclusive determination without incurring substantial expense. The nature of the oil and gas leasing and title regime in the U.S. is such that interests in tracts of acreage may be represented by many leases and other agreements affecting oil and gas rights and access and obtaining absolute confirmation of chain of title would be time consuming and expensive. While the Company will conduct a title review of a particular area prior to commencement of drilling there can be no assurance of title. Title may be subject to unregistered liens and other defects which, if affecting a core area, could have a material adverse effect on the Company, its financial condition, results of operations and prospects.

Permits and Licenses

The activities of the Company are subject to government approvals, various laws governing prospecting, development, land resumptions, production taxes, labor standards and occupational health, safety, toxic substances and other matters, including issues affecting local native populations. Although the Company believes its planned development work is in accordance with all applicable rules and regulations, no assurance can be given that new rules and regulations will not be enacted or that existing rules and regulations will not be applied in a manner which could limit or curtail production or development. Amendments to current laws and regulations governing operations and activities of exploration and quarrying, or more stringent implementation thereof, could have a material adverse impact on the business, operations and financial performance of the Company. Further, the exploration and development permits and licenses that have and may be issued in respect of each project may be subject to conditions which, if not satisfied, may lead to the revocation of such permits and licenses. In the event of revocation, the value of the Company's investments in such projects may decline.

Reserve Estimates

No current reserves have been estimated in respect of the Company's oil & gas properties. There are numerous uncertainties inherent in estimating quantities of oil, natural gas and natural gas liquids reserves and resources and associated cash flows, including many factors beyond the Company's control. In general, estimates of economically recoverable oil and natural gas reserves and the future net cash flows from them are based upon a number of variable factors and assumptions, such as historical production from the properties, production rates, ultimate reserve recovery, timing and amount of capital expenditures, marketability of oil and natural gas, royalty rates, the assumed effects of regulation by governmental agencies and future operating costs, all of which may vary from actual results. The Company's actual production, revenues, taxes and development and operating expenditures with respect to its reserves will vary from estimates thereof and such variations could be material.

Prices and Markets for Oil and Natural Gas

Oil and natural gas are commodities whose prices are determined based on world demand, supply and other factors, all of which will be beyond the control of the Company. World prices for oil and natural gas have fluctuated widely in recent years. Any material decline in prices could result in a reduction of net production revenue. Certain wells or other projects may become uneconomic as a result of a decline in world oil prices or natural gas prices, leading to a reduction in the volume of the Company's oil and gas reserves. The Company might also elect not to produce from certain wells at lower prices. All of these factors could result in a material decrease in the Company's future net production revenue, causing a reduction in its oil and gas acquisition and development activities. Prices for oil and gas are subject to large fluctuations in response to relatively minor changes in the supply of and demand for oil and gas, market uncertainty and a variety of additional factors beyond the control of the Company. These factors include economic conditions, in the United States and Canada, the actions of OPEC, governmental regulation, political stability in the Middle East and elsewhere, the foreign supply of oil and gas, risks of supply disruption, the price of foreign imports and the availability of alternative fuel sources. Any substantial and extended decline in the price of oil and gas would have an adverse effect on the Company's carrying value of its reserves, borrowing capacity, revenues, profitability and cash flows from operations and may have a material adverse effect on the Company's business, financial condition, results of operations and prospects.

Lack of Adequate Insurance

In the course of exploration, development and production of mineral properties, certain risks, and in particular, unexpected or unusual geological operating conditions including rock bursts, cave-ins, fires, flooding and earthquakes may occur. It is not always possible to fully insure against such risks and the Company may decide not to take out insurance against such risks as a result of high premiums or other reasons. Should such liabilities arise, they could reduce or eliminate any future profitability and result in increasing costs and a decline in the value of the securities of the Company.

Competition

The oil and gas industry is highly competitive. The Company's competitors for the acquisition, exploration, production and development of oil and natural gas properties, and for capital to finance such activities will include companies that have greater financial and personal resources available to them than the Company.

Risks Associated with Joint Operating Agreements

The development of the Company's oil & gas properties is governed by a various joint operating agreements. The existence or occurrence of a disagreement or dispute with or among the other parties to such agreement could have a material adverse impact on the Company's profitability or the viability of its interests, which could have a material adverse impact on the Company's business prospects, results of operations and financial condition.

Environmental Risks

All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of international conventions and provincial and municipal laws and regulations. Environmental legislation provides for, among other things, restrictions and prohibitions on spills, releases or emissions of various substances produced in association with oil and gas operations. The legislation also requires that wells and facility sites be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. Compliance with such legislation can require significant expenditures and a breach may result in the imposition of fines and penalties, some of which may be material. Environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liability and potentially increased capital expenditures and operating costs. There is no assurance that future changes in environmental regulation, if any, will not adversely affect the Company's operations or prevent operations all together. Government approvals and permits are currently, and may in the future be, required in connection with the Company's operations, which could potentially make operations expensive or prohibit them altogether. To the extent such future approvals are required and not obtained, the Company may be curtailed or prohibited from proceeding with planned exploration or development of the Properties or from commencing production.

Availability of Drilling Equipment and Access Restrictions

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 the Company and may delay exploration and development activities.

Current Global Financial Conditions

Current global financial conditions have been subject to increased volatility and numerous financial institutions have either gone into bankruptcy or have had to be rescued by governmental authorities. Access to public financing has been negatively impacted by both sub-prime mortgages and the liquidity crisis affecting the asset-backed commercial paper market. These factors may impact the ability of the Company to obtain equity or debt financing in the future and, if obtained, on terms favourable to the Company. If these increased levels of volatility and market turmoil continue, the Company's operations could be adversely impacted and the value and the price of the Company's shares could continue to be adversely affected.

Geo Political Risks

The marketability and price of oil and natural gas that may be acquired or discovered by the Company is and will continue to be affected by political events throughout the world that cause disruptions in the supply of oil. Conflicts, or conversely peaceful developments, arising in the Middle East, and other areas of the world, have a significant impact on the price of oil and natural gas. Any particular event could result in a material decline in prices and therefore result in a reduction of the Company's net production revenue.

Transportation Costs

Disruption in or increased costs of transportation services could make oil and natural gas a less competitive source of energy or could make the Company's oil and natural gas less competitive than other sources. The industry depends on rail, trucking, ocean-going vessels, pipeline facilities, and barge transportation to deliver shipments, and transportation costs are a significant component of the total cost of supplying oil and natural gas. Disruptions of these transportation services because of weather related problems, strikes, lockouts, delays or other events could temporarily impair the ability to supply oil and natural gas to customers and may result in lost sales. In addition, increases in transportation costs, or changes in transportation costs for oil and natural gas produced by competitors, could adversely affect profitability. To the extent such increases are sustained, the Company could experience losses and may decide to discontinue certain operations forcing the Company to incur closure and/or care and maintenance costs, as the case may be. Additionally, lack of access to transportation may hinder the expansion of production at some of the Company's properties and the Company may be required to use more expensive transportation alternatives.

Capacity of Pipelines, Refineries and Natural Gas Processing Facilities

Although expansion projects are ongoing, the availability of sufficient marketing capacity continues to affect the oil and natural gas industry and limit the ability to produce and to market natural gas production. The rapid expansion of production in the Company's core area may create temporary disruptions in the capacity of marketing infrastructure. In addition, the pro-rationing of capacity on the inter-state pipeline systems also continues to affect the ability to export oil and natural gas.

Reliance on Key Individuals

The Company's success depends to a certain degree upon certain key members of the management. It is expected that these individuals will be a significant factor in the Company's growth and success. The loss of the service of members of the management and certain key employees could have a material adverse effect on the Company.

Conflicts of Interest

Certain of the Company's directors are also directors, officers or shareholders of other companies that are engaged in the business of acquiring, developing and exploiting natural resource properties. Such associations may give rise to conflicts of interest from time to time. Such a conflict poses the risk that the Company may enter into a transaction on terms which place the Company in a worse position than if no conflict existed. The directors are required by law to act honestly and in good faith with a view to the best interest of the Company and to disclose any interest which they may have in any project or opportunity of the Company. However, each director has similar obligations to other companies for which such director serves as an officer or director. If a conflict of interest arises at a meeting of the board of directors, any director in a conflict is required disclose his interest and abstain from voting on such matter. In determining whether or not the Company will participate in any project or opportunity, the board of directors will primarily consider the degree of risk to which the Company may be exposed and its financial position at that time.

Financial Instruments

The Company has classified its financial instruments as follows:

- Cash – as FVTPL;
- Accounts receivable and operators bond – as loans and receivables; and
- Accounts payable and accrued liabilities, liabilities associated with assets held-for-sale and convertible notes – as other financial liabilities.

The Company's risk exposure and the impact on the Company's financial instruments are summarized below:

Fair value
The carrying values of accounts receivable, accounts payable and accrued liabilities, and liabilities associated with assets held-for-sale approximate their fair values due to the short-term maturity of these financial instruments. The fair value of the operators bond also approximates its carrying value. The debt component of the convertible notes was recognized initially at fair value and thereafter has been accounted for at amortized cost.

Credit risk
Credit risk is the risk of potential loss to the Company if the counterparty to a financial instrument fails to meet its contractual obligations.

The Company's credit risk is primarily attributable to its cash and accounts receivable. The credit risk associated with cash is mitigated since the cash is held at major financial institutions with high credit ratings. Accounts receivable consists primarily of trade receivables outstanding from operators of its oil and gas interests. To mitigate this risk, the Company regularly reviews the collectability of accounts receivable to ensure there is no indication that these amounts will not be fully recoverable.

Market risk

Market risk is the risk that the fair value or future cash flows of a financial instrument will fluctuate due to changes in the market prices. Market risk is comprised of three types of risk: interest rate risk, foreign currency risk and other price risk.

(i) Interest rate risk

To the extent that payments made or received on the Company's monetary assets and liabilities are affected by changes in prevailing market interest rates, the Company is exposed to interest rate cash flow risk.

To the extent that changes in prevailing market interest rates differ from the interest rates in the Company's monetary assets and liabilities, the Company is exposed to interest rate price risk.

The Company's exposure to interest rate risk is minimal.

(ii) Foreign currency risk

Foreign currency risk is the risk that the future cash flow of financial instruments will fluctuate as a result of changes in foreign exchange rates. The Company's financing is raised in Canadian dollars, but a portion of the Company's operations are conducted in United States dollars. Therefore, the Company is impacted by changes in the exchange rate between the Canadian and United States dollars.

The following assets and liabilities represent the Company's exposure to foreign currency risk:

	October 31, 2014 (USD)	**January 31, 2014 (USD)**
Cash	$32,721,659	$8,595,184
Accounts receivable	876,370	1,856,863
Operators bond	25,000	25,000
Accounts payable and accrued liabilities	(862,662)	(223,073)
Liabilities associated with assets held for sale	-	(56,151)
Net	$32,760,367	$ 10,197,823
Canadian dollar equivalent	CAD $36,760,408	CAD $ 11,358,335

Based on the above net exposures as at October 31, 2014, a 5% change in the Canadian/US exchange rate would impact the Company's net loss and comprehensive loss by approximately $1,838,000 (January 31, 2014 - $568,000).

(iii) Other price risk

Other price risk is the risk that the fair value or future cash flows of a financial instrument will fluctuate due to changes in the market prices, other than those arising from interest rate risk or foreign currency risk. The Company is not exposed to significant other price risk.

Liquidity risk

Liquidity risk is the risk that the Company will encounter difficulty in satisfying financial obligations as they become due. The Company manages liquidity risk through maintaining sufficient cash on hand to meet its obligations as they become due. As at October 31, 2014, the Company had cash of $34,823,565, accounts receivable of $919,947, current liabilities of $948,970 and convertible notes totaling CAD $38,590,000 plus accrued interest at 8% per annum on maturity. The current liabilities are due within three months of year-end and the convertible notes mature April 2, 2018. As of October 31, 2014, $25,000,000 was drawn under this facility. The term is four years with cash interest of LIBOR (with a floor of 1%) plus 7% plus payment in kind ("PIK") interest of 5% per annum. Additionally $284,552 of PIK interest was accrued to the outstanding balance of the facility. Cash interest to be paid monthly; principal and PIK interest paid upon maturity.

The Company owns varying interests in oil and gas properties subject to joint operating agreements, which provide, among other things, that the Company make advance payments from time to time to fund its share of estimated exploration and evaluation costs. The Company may not have sufficient working capital and future cash flow from operations to fund its share of the agreed-upon estimated costs of proposed development activities. As a consequence, the Company may have to secure new sources of capital, which is not assured, to maintain its interests in such proposed development.

As at October 31, 2014 and the date of this report, the Company had outstanding long term convertible notes in the principal amount of CAD $38,590,000, (January 31, 2014 - CAD $38,825,000), which are due on April 2, 2018.

Shareholder's Equity and Outstanding Share Data

The authorized share capital of the Company consists of an unlimited number of common shares. As of October 31, 2014 and the date of this report, there were 87,844,821 common shares outstanding.

As of the date of this report, the Company had the following stock options and warrants outstanding:

Stock options

Number of Options	Number of Options Exercisable	Exercise Price (CAD)	Expiry Date	Weighted Average Remaining Contractual Life (Years)
1,650,000	1,650,000	$ 0.12	June 22, 2016	1.64
250,000	250,000	$ 0.19	July 15, 2016	1.70
250,000	250,000	$ 0.21	September 16, 2016	1.85
250,000	250,000	$ 0.19	October 18, 2016	1.96
100,000	100,000	$ 0.53	November 25, 2016	2.07
250,000	212,500	$ 0.67	December 16, 2016	2.13
150,000	105,000	$ 1.35	July 8, 2017	2.69
2,900,000	2,817,500			1.80

Warrants

Number of Warrants	Weighted Average Exercise Price (CAD)	Expiry Date
500,000	$ 0.18	June 21, 2016

Restricted Share Units

The Company has a restricted share unit plan, which provides that the Board of Directors of the Company may from time to time, in its discretion, and in accordance with Exchange requirements, issue to directors, officers, employees and technical consultants to the Company, restricted share units ("RSUs"). The number of common shares of the Company that may be reserved for issuance must not exceed 4,681,982 shares as of October 31, 2014. In addition, common shares reserved for issuance of RSUs will reduce the number of shares that may be made subject to the incentive stock options under the Company's 10% rolling option plan. The number of common shares reserved for issuance, together with any other compensation arrangements, to any one person in any 12-month period will not exceed 5% of the issued and outstanding common shares. The number of common shares reserved for issuance together with any other compensation arrangements granted to all technical consultants and will not exceed 2% of the issued and outstanding common shares. The number of RSUs granted to any one person cannot exceed 5% of the issued and outstanding common shares.

The Company issued 1,200,000 RSUs with a value of CAD $2,991,500. Each RSU, upon vesting, gives the holder the right to receive one common share. Unless otherwise approved by the Company's Board of Directors, all of the RSUs will vest upon the occurrence of a "change of control transaction"; as such term is defined in the RSU award agreements. In the absence of a change of control transaction or other acceleration of vesting by the Company's Board of Directors, unvested RSUs will expire five years from the date of grant. Vested RSUs will be settled, at the election of the Company, by way of: (i) issuance of common shares from treasury; (ii) payment to the RSU holder of an amount of cash equal to the market price of the common shares on the vesting date; or (iii) any combination thereof.

Reserves Data and Other Oil and Gas Information

Our independently prepared reserves assessment and evaluation of oil and gas properties effective January 31, 2014 have been prepared in accordance with mandated National Instrument 51-101 *Standards of Disclosure for Oil and Gas Activities of Canadian Securities Administrators*. A summary of our reports is available on SEDAR at www.sedar.com.

Internal Controls Over Financial Reporting

Changes in Internal Control over Financial Reporting ("ICFR")

In connection with National Instrument 52-109, Certification of Disclosure in Issuer's Annual and Interim Filings ("NI 52-109") adopted in December 2008 by each of the securities commissions across Canada, the Chief Executive Officer and Chief Financial Officer of the Company will file a Venture Issuer Basic Certificate with respect to financial information contained in the unaudited interim financial statements and the audited annual financial statements and respective accompanying Management's Discussion and Analysis. The Venture Issue Basic Certification does not include representations relating to the establishment and maintenance of disclosure controls and procedures and internal control over financial reporting, as defined in NI52-109.

Contingencies

There are no contingent liabilities.

Management's Responsibility For Financial Statements

The information provided in this report, including the condensed consolidated interim financial statements, is the responsibility of management. In the preparation of these statements, estimates are sometimes necessary to make a determination of future values for certain assets or liabilities. Management believes such estimates have been based on careful judgments and have been properly reflected in the condensed consolidated interim financial statements.

Other MD&A Requirements

Additional disclosure of the Company's technical reports, material change reports, news releases and other information can be obtained on SEDAR at www.sedar.com.

Directors and Officers

David Gibbs	President, Chief Executive Officer and Director
Dan Carriere	Director and Non-Executive Chairman
Eric Boehnke	Director and Executive Vice Chairman
Murray Oliver	Director
William McCartney	Director
Ken Shannon	Director
George Morris	Chief Operating Officer
Keith Godwin	Chief Financial Officer
William McMoran	Vice President Exploration
Daniel Morris	Vice President Geoscience
Anthony Alvaro	Vice President Corporate Development
Deborah Cotter	Secretary

Contact Person

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