TERRACE ENERGY CORP.
(the “Company” or “Terrace”)
MANAGEMENT’S DISCUSSION AND ANALYSIS
OF THE COMPANY’S FINANCIAL CONDITION AND RESULTS OF OPERATIONS
FOR THE SIX AND THREE MONTHS ENDED JULY 31, 2015 AND 2014

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 September 29, 2015 and should be read in conjunction with the unaudited condensed consolidated interim financial statements for the six and three months ended July 31, 2015 and 2014 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, 2015 and 2014, 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 its projects, 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 consolidated 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 consolidated financial statements do not conform with, nor are they reconciled to, accounting principles generally accepted in the United States.

Company 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 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%
TEC Olmos, LLC	USA	100%

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

Executive Overview of Second Quarter

During late 2014 and the first half of 2015, management implemented measures to preserve capital and protect our core assets until such time as market conditions become more favorable. The development activities at our Olmos Tight Sandstone Development Project (the "STS Olmos Project") were reduced down to the minimum operations required to maintain our leasehold and contractual obligations. The Company and its partner made the decision to release the drilling rig which had been working on the STS Olmos Project when the contractual obligations were fulfilled in late first quarter. In addition, the Company deferred completion activities of two recently drilled three-well pads until the costs could be renegotiated in response to the existing market conditions. The Company also took actions to reduce or eliminate capital expenditures at the Maverick County and Big Wells projects. On the financial side the Company renegotiated the terms of the Credit Facility and engaged an investment bank to provide advice regarding financial options and strategic alternatives for the Company.

The drop in oil prices has had a material impact on service costs, which resulted in substantial cost savings. The costs to complete and put into production the three wells, which make up the STS 6H pad, were re-bid during the quarter and the new price quotations resulted in a cost of approximately 70% of the completion costs for previous wells similarly developed. Consequently, the decision was made to proceed with completion activities for the STS 6H pad. These three wells were completed and placed on production during the second quarter with results consistent with expectations.

The completion of the STS 6H pad fulfills the remaining leasehold obligations necessary to hold the Company's acreage for the remainder of 2015. Consequently, the Company is taking a judicious approach to balancing near term liquidity issues with long term asset development. The Company and its partners have elected to defer the completion of the remaining three well pad, the STS A-605H pad until early 2016. These three completions, when executed, will satisfy the minimum obligations to hold the leasehold position through 2016.

The STS Project continues to provide consistent, repeatable results. To efficiently identify and acquire additional acreage for future growth of this project, the Company entered into an agreement during July 2015 with its partner on the STS Olmos Project defining an area of mutual interest (the "AMI") covering more than 200,000 acres surrounding our existing STS Olmos Project acreage. The agreement provides that if either party acquires an interest or a right to an interest within the AMI, the other party shall have the right to participate in such interest up to 50% interest. This agreement ensures that Terrace and its partner's interests are aligned and will work together as acreage acquisition opportunities are identified and evaluated.

Also during the quarter, the BlackBrush Terrace LP ("BTLP Partnership") drilled and completed an additional Eagle Ford Shale well at the Maverick County Project and completed a previously drilled Buda Limestone well. Flowback operations on the Eagle Ford Shale well were commenced late in the quarter and initial results are very encouraging. Prior to these activities, in order to preserve capital, the Company sought and came to an agreement with its partner wherein the partner will contribute the Company's share of costs to drill and complete these additional wells in return for a proportionate dilution in the Company's partnership interest. As a result, the Company's ownership interest in the BTLP Partnership will be reduced from 50% to approximately 45%.

In light of the current economic conditions the Company determined it is not prudent to use its resources to drill additional wells on its Big Wells project. Accordingly, the Company forfeited its rights under the farmout agreement.

Outlook

The Company will continue to monitor market conditions and well performance to determine the optimum timing to resume drilling activity on the STS Olmos Project. Based on the current economic environment, development drilling on this project remains economically viable, but the Company is taking a judicious approach to balancing near term liquidity issues with long term asset development.

The Company previously reached an agreement with its lender that, among other things, restricted its ability to further draw down the credit facility to fund future drilling activities on the STS Olmos Project. The Company, however, does not have any remaining development activity planned for the current fiscal year and believes it has sufficient liquidity to fund the completion operations on the remaining three wells at the STS Olmos Project in the first half of 2016. The lender remains supportive of the Company's plans and the Company will continue to work closely with the lender to assess market conditions and well economics over the next fiscal year. The Company and its financial advisor continue to evaluate financial options and strategic alternatives which would ultimately allow for a recapitalization of the Terrace STS, LLC entity which the Company agreed to in its recent Credit Agreement modification.

The Company believes the STS Project will continue to provide consistent, repeatable results and accordingly the Company is actively seeking opportunities to expand its acreage position by accumulating a patient inventory of leases which have terms that do not require capital expenditure in the near term. Our partner has recently leased approximately 8,800 gross acres immediately adjacent to our existing STS Olmos Project acreage which has a three year primary term and does not require any near term drilling to maintain the lease. In accordance with the AMI agreement, our partner has offered for the Company to participate and acquire a 50% interest in the rights to the Olmos Sandstone on this leasehold for $1.53 million. The Company intends to exercise its option.

At the Maverick County Project, the BTLP Partnership is in discussions with Shell to confirm that the completion of the Eagle Ford Shale and Buda Limestone wells will satisfy its drilling obligations for the year in order to reduce capital expenditures preserve capital until market conditions improve.

The Company continues to strongly believe in its STS Olmos Project and its Maverick County project and is committed to enhancing shareholder value by exploiting them as market conditions improve. As a result, the Company is evaluating, together with its corporate advisors, different financial options, including, but not limited, to joint venturing the exploration and development of its assets, the sale of assets and the combination of the Company with a strategic partner.

Exploration and Development Assets

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

Olmos Tight Sandstone Development Project

In November 2011, the Company entered into an agreement, through a wholly-owned subsidiary, to acquire varying working and net revenue interests, which initially averaged approximately 26.88% and 20.16%, 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 (the "**Original STS Olmos Leases**") subject to participation in the development of additional wells proposed from time to time by the project's operator.

Through April 30, 2015, the Company has participated in the reentry and horizontal extension of the evaluation well and the drilling of twenty additional development wells on the Original STS Olmos Leases, all of which were drilled horizontally with lateral lengths averaging approximately 4,500 feet. As of July 31, 2015, seventeen of these wells were successfully completed in the Olmos tight sandstone formation using multi-hydraulic fracturing techniques. The remaining three wells drilled subsequent to year-end are currently awaiting completion. The Company's share of the aggregate costs to drill, complete and place into production these wells through July 31, 2015 was $31,640,499.

The Company and its partner initiated a "pad drilling" development program in August 2014. During the fourth calendar quarter, drilling and completion operations were completed on the first three-well pad, the Section 6 pad in McMullen County, and the Company initiated production from this first pad during January 2015. As mentioned above, the Company's second three-well pad, the Section 5 pad in LaSalle County, was drilled during the fourth calendar quarter. Fracing operations began in January 2015 and have been completed subsequent to year end. Production from this three-well pad commenced in February 2015. A third pad was drilled in the prior year and one additional pad consisting of three wells has been drilled since year end with all six wells successfully encountering the target zones. In June 2015, three of these latest wells had been completed and placed on production with the three remaining wells to be completed at a later date. The Company will continue to monitor market conditions and well performance to determine the optimum timing of completion of the second three-well pad and resumption of drilling activity.

In January 2014, the Company 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 in the Northwest AWP Area in McMullen County, Texas. On August 3, 2014 the Company spud the Quintanilla OL 1-H well, an evaluation well that the Company committed to drill under the agreements. The evaluation well was successfully completed during October 2014 and is currently producing at rates consistent with the performance of the STS Olmos wells earning the Company interests in approximately 199 gross mineral acres.

During April 2015, the Company entered into additional agreements, through a wholly-owned subsidiary, to earn a 75% working interest and a 52.5% net revenue interest, as to the Olmos formation only, in certain leases south of the Original STS Olmos Leases covering initially 640 gross mineral acres in LaSalle County, Texas. Under the terms of these agreements, the Company is required to commence drilling a well (paying 100% of the cost) on this acreage by late September 2015 or pay liquidated damages of $500,000. Due to the current market conditions, the Company has initiated discussions with the farmor to obtain more time to drill and complete the well. There are no assurances the Company will secure an agreement to allow for additional time to drill the well on terms acceptable to the Corporation or on any terms.

Our partner has recently leased approximately 8,800 gross acres immediately adjacent to our existing STS Olmos Project acreage which has a three year primary term and does not require any near term drilling to maintain the lease. In accordance with the AMI agreement, our partner has offered for the Company to participate and acquire a 50% interest in the rights to the Olmos Sandstone on this leasehold for $1.53 million. The Company intends to exercise its option.

Maverick County Project (Investment in BlackBrush Terrace LP)

The Company and its partner, BlackBrush Oil & Gas, LP ("**BlackBrush**") organized a special purpose limited partnership, the BlackBrush Terrace LP (the "**BTLP**"), 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 BTLP may secure the WI through a combination of cash payments, which have been made, and drilling obligations. The material terms of the farmout agreement between the SPLP and Shell Oil are as follows:

1. the BTLP 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 each well drilled under this agreement, the BTLP may request an assignment of 50% of Shell Oil's interest in such well;

3. upon making the Carry Payment in full, the BTLP shall have the option, but not the obligation, to pay 50% of all development costs for the right to participate in 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.

The BTLP 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 numerous positive shows of hydrocarbons. 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. Based on the results of this initial well, the BTLP and Shell Oil have agreed to defer further evaluation of the Pearsall Shale and refocus exploration activity to concentrate on the Eagle Ford Shale and other, shallower cretaceous formations.

During 2013, the BTLP successfully tested the Eagle Ford formation through the re-entry and completion of the SWEPI Chittim #F-1H, which was previously drilled and shut in by Shell Oil in 2011 and the drilling and completion of a second well to test the Eagle Ford and Buda Limestone Formations. To date, these well have produced in excess of 50,000 BOE (gross) from the Eagle Ford Shale and are continuing to produce.

The results of these wells were sufficiently encouraging that BTLP partnership was able to successfully renegotiate 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 BTLP partnership 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 January 1, 2015 until the total required drilling carry of $104 million has been spent. Prior to January 1, 2015, the BTLP partnership spent approximately $32 million towards this obligation. The BTLP partnership 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.

After having amended the agreement with Shell, the BTLP partnership drilled four 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. Most notably, these wells confirm the presence of the Eagle Ford Shale in three separate areas of the project covering at least 50,000 gross acres.

Subsequent to the close of the first quarter, the BTLP partnership drilled a new Eagle Ford Shale well, the Chittim #10H, which was completed during the quarter. Flowback operations on the well were commenced during July 2015 and after recovering approximately 23% of the load water from the frac job, the well began to consistently produce oil. As the well reached a 46% frac water load recovery, the well was producing consistently at a rate of over 400 barrels of oil per day with no artificial lift. It also performed a minimal completion on one of the previously drilled Buda Limestone wells, the Chittim #4H to evaluate the production potential of the Buda Limestone in that area of the ranch. The Chittim #4H did not produce commercial hydrocarbons during the test flowback period and the well has been shut in for further evaluation. Prior to these activities, the Company sought and came to an agreement with its partner wherein to preserve capital, the Company would not contribute its share of costs to drill and complete these additional wells. As a result, the Company's 50% ownership interest in the BTLP partnership will be reduced from 50% to approximately 45%. In accordance with the provisions of the partnership agreement, the Company will not be entitled to any revenue allocations or distribution of revenue proceeds from these wells.

BTLP partnership is currently in discussions with Shell Oil to reduce the amount otherwise required to be spent during the 2015 calendar year. It is expected these two wells will satisfy the balance of the financial obligations under the agreement. However, there can be no assurances that Shell Oil will agree. In such event the BTLP partnership will be obligated to either incur additional exploration expenses or pay liquidated damages of $2 million in the first quarter of 2016.

The Company has a carrying value in the partnership of $18,016,870 at July 31, 2015, which includes $23,679,357 in advances representing 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 cumulative net losses of the partnership of $5,662,487 of which approximately $4,631,405 of the cumulative loss was attributable to the impairment charges primarily attributable to the precipitous drop in oil prices experienced in late 2014.

Big Wells Project

In February, 2014, the Company 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 depth limited to the Buda Limestone formation in Dimmit and Zavala Counties, Texas. Under the terms of the agreements, the Company had the option to drill a series of "Earning Wells", each of which allowed the Company to secure interests in 640 gross mineral acre tracts.

During the fourth fiscal quarter 2015, the Company completed its first Earning Well, the Price #1H well. The well was critical to establishing the presence of commercially producible hydrocarbons and validating the geological concept for the project, however, it did not result in the addition of proven or probable reserves due to formation water encountered at the base of the formation. As a consequence, the Company expensed the costs related to the Price evaluation well, which amounted to $7,250,754 of which $594,185 was incurred and expensed during the six month period ended July 31, 2015.

In light of the current economic conditions the Company determined it is not prudent to use its resources to drill additional wells on its Big Wells project. Accordingly, the Company forfeited its rights under the farmout agreement and the Company recorded impairment expense of $2,436,924 related to the seismic data it had acquired over the acreage.

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 acres in Dimmit and LaSalle counties.

During the fiscal year ended January 31, 2014, the Company incurred all of the costs necessary and was assigned its working interests in the properties that comprise this project. Upon completing a project review, management determined that the project was no longer a core asset and decided to solicit bids from prospective purchasers.

The Company has reclassified the assets and liabilities associated with the Company's interests in the project from their respective balance sheet classifications to "assets held for sale".

Seismic Data Acquisition

In June, 2014 and August, 2014 the Company acquired a non-exclusive license to 3-D seismic data totaling $2.3 million covering the recently relinquished farmout acreage in the Big Wells Project. Of this, $1.2 million of the additional data was 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 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. We have initiated discussions with the provider to restructure this agreement and eliminate any commitments to purchase additional data. There can be no assurances that these discussions will result in modifying the existing agreements, including the remaining commitments of the Company to purchase additional data.

Results of Operations

For the six months ended July 31, 2015 and 2014

Net loss for the six months ended July 31, 2015 was $9,967,353 compared to net loss of $1,651,367 for the six months ended July 31, 2014. The results are summarized as follows:

	2015	2014
Oil and gas revenues (net of royalties)	$ 3,847,845	$ 4,045,870
Direct operating expenses	1,003,330	959,406
Depreciation and depletion	3,672,721	1,411,970
Operating income (loss)	(828,206)	1,674,494
Equity income (loss) in partnership	(106,013)	(85,903)
	(934,219)	1,588,591
General and administrative expenses	2,059,759	1,771,629
Financing Costs	3,198,497	1,767,642
Foreign exchange (gain) loss	740,697	(380,799)
Share-based payments	3,072	99,951
Impairments	3,031,109	(18,465)
	9,033,134	3,239,958
Net loss for the period	$ (9,967,353)	$ (1,651,367)

Oil and gas sales for the six months ended July 31, 2015 were $4,048,765 less royalties of $200,920 compared to $4,261,075 less royalties of $215,205 for the six months ended July 31, 2014.

The Company's aggregate share of sales from these wells before deducting for royalty for the six months ended July 31, 2015 was approximately 98,425 barrels of oil and liquids at an aggregate average price of $36.21 per barrel of oil equivalent and 206,055 thousand cubic feet of natural gas at an average price of $2.35 per thousand cubic feet as compared to the previous period of approximately 52,201 barrels of oil and liquids at an average price of $68.95 per barrel of oil equivalent and 124,406 thousand cubic feet of natural gas at an average price $4.69 per thousand cubic feet.

*Direct operating expense*s for the six months ended July 31, 2015 were $1,003,330 compared to $959,406 for the six months ended July 31, 2014. During the six months ended July 31, 2015 we had seventeen wells producing, whereas during the six months ended July 31, 2014 we had nine wells producing. Operating loss net of depreciation and depletion expenses of $3,672,721 was $828,206 for the six months ended July 31, 2015 and operating income net of depreciation and depletion expenses of $1,411,970 was $1,674,494 for the same period in 2014. The increase in depreciation and depletion expenses was primarily due to the increase in volumes produced and sold. Additionally, depreciation and depletion expenses were higher due to wells that were drilled and completed in a higher price environment than our original wells and due to the more sophisticated, higher cost well completions utilized on our first two pads.

Equity income (loss) in partnership represents the Company's pro-rata share of income or loss of the BlackBrush Terrace LP. For the six months ended July 31, 2015 the Company's share of the partnership loss was $106,013 compared to the Company's share of the partnership net loss of $85,903 for the six months ended July 31, 2014.

General and administrative expenses for the six months ended July 31, 2015 were $2,059,759 compared to $1,771,629 for the six months ended July 31, 2014. 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 $241,008 as result of employees added to the operational staff in Houston.

Financing costs for the six months ended July 31, 2015 were $3,198,497 compared to $1,767,642 for the six months ended July 31, 2014 which is primarily attributable to the Credit Facility which the Company entered into during June 2014. Interest expense includes a non-cash expense of $314,927 which represents accretion of the convertible notes during the period compared to $340,618 for the six months ended July 31, 2014, Additionally, during the six months ended July 31, 2015 the Company incurred interest expense on the new Credit Facility for the development of our STS Olmos project includes non-cash expense of $650,585 which represents PIK interest. There was no interest expense on the Credit Facility in the prior period.

Foreign exchange (gain) loss for six months ended July 31, 2015 was a loss of $740,697 compared to a gain of $380,799 for the six months ended July 31, 2014. The change in foreign exchange was due to fluctuations in the USD exchange rate during the period.

Share-based payments for the six months ended July 31, 2015 were $3,072 compared to $99,951 for the six months ended July 31, 2014 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 six months ended July 31, 2015 was a charge of $3,031,109 compared to a recovery of 18,465 for the six months ended July 31, 2014. During the six months ended July 31, 2015, the Company recognized an impairment of $594,185 on its Exploration and Evaluation assets at Big Wells incurred during the period to complete the well testing related to the Price well which did not result in any proved or probable reserves being assigned to the well after it was completed and tested. Additionally, during the period, the Company determined it is not prudent to use its resources to drill additional wells on its Big Wells project. Accordingly, the Company forfeited its rights under the farmout agreement and the Company recorded impairment expense of $2,436,924 related to the seismic data it had acquired over the acreage.

For the three months ended July 31, 2015 and 2014

Net loss for the quarter ended July 31, 2015 was $5,006,864 compared to net loss of $1,422,583 for the quarter ended July 31, 2014. The results are summarized as follows:

	2015	2014
Oil and gas revenues (net of royalties)	$ 1,911,533	$ 1,503,040
Production and operating	552,872	495,857
Depreciation and depletion	1,924,390	606,883
Operating income	(565,729)	400,300
Equity loss in partnership	(39,998)	(29,065)
	(605,727)	371,235
General and administrative expenses	1,010,978	1,078,246
Financing Costs	1,454,528	917,097
Foreign exchange (gain) loss	(719,962)	(193,273)
Share-based payments	-	41,219
Impairments	2,655,593	(49,471)
	4,401,137	1,793,818
Net loss for the period	$ (5,006,864)	$ (1,422,583)

Oil and gas sales for the quarter ended July 31, 2015 were $2,003,726 less royalties of $92,193 compared to $1,586,614 less royalties of $83,574 for the quarter ended July 31, 2014.

The Company's aggregate share of sales from these wells before deducting for royalty for the quarter ended July 31, 2015 was approximately 46,451 barrels of oil and liquids at an aggregate average price of $38.33 per barrel of oil equivalent and 88,186 thousand cubic feet of natural gas at an average price of $2.53 per thousand cubic feet as compared to the previous period of approximately 20,766 barrels of oil and liquids at an average price of $64.82 per barrel of oil equivalent and 57,524 thousand cubic feet of natural gas at an average price $4.50 per thousand cubic feet.

Production and operating expenses for the quarter ended July 31, 2015 were $552,872 compared to $495,857 for the quarter ended July 31, 2014. During the quarter ended July 31, 2015, seventeen wells were producing, whereas during the quarter ended July 31, 2014, only nine wells were producing. Operating loss net of depreciation and depletion expenses of $1,924,390 was $565,729 for the quarter ended July 31, 2015 and operating income net of depreciation and depletion expenses of $606,883 was $400,300 for the same period in 2014. The increase in depreciation and depletion expenses was primarily due to the increase in volumes produced and sold. Additionally, depreciation and depletion expenses were higher due to wells that were drilled and completed in a higher price environment than our original wells and due to the more sophisticated, higher cost well completions utilized on our first two pads.

Equity income (loss) in partnership represents the Company's pro-rata share of income or loss of the BlackBrush Terrace LP. For the quarter ended July 31, 2015 the Company's share of the partnership loss was $39,998 compared to the Company's share of the partnership loss of $29,065 for the quarter ended July 31, 2014.

General and administrative expenses for the quarter ended July 31, 2015 were $1,010,978 compared to $1,078,246 for the quarter ended July 31, 2014. 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.

Financing costs for the quarter ended July 31, 2015 were $1,454,528 compared to $917,097 for the quarter ended July 31, 2014 which is primarily attributable to the convertible notes the Company issued and the Credit Facility which the Company entered into during June 2014. Interest expense includes a non-cash expense of $146,521 which represents accretion of the convertible notes during the period compared to $173,318 for the quarter ended July 31, 2014, Additionally, during the six months ended July 31, 2015 the Company incurred interest expense on the new Credit Facility for the development of our STS Olmos project includes non-cash expense of $332,713 which represents PIK interest. There was no interest expense on the Credit Facility in the prior period.

Foreign exchange (gain) loss for quarter ended July 31, 2015 was a gain of $719,962 compared to a gain of $193,273 for the quarter ended July 31, 2014. The change in foreign exchange was due to fluctuations in the USD exchange rate during the period and the change in functional currency in two subsidiaries.

Share-based payments for the quarter ended July 31, 2015 were $nil compared to $41,219 for the quarter ended July 31, 2014 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 quarter ended July 31, 2015 was a charge of $2,655,593 compared to a recovery of $49,471 for the quarter ended July 31, 2014. During the quarter ended July 31, 2015, the Company recognized an impairment of $218,669 on its Exploration and Evaluation assets at Big Wells incurred during the quarter to complete the well testing related to the Price well which did not result in any proved or probable reserves being assigned to the well after it was completed and tested. Additionally, during the period, the Company determined it is not prudent to use its resources to drill additional wells on its Big Wells project. Accordingly, the Company forfeited its rights under the farmout agreement and the Company recorded impairment expense of $2,436,924 related to the seismic data it had acquired over the acreage.

Summary of Quarterly Results

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

	July 31, 2015	April 30, 2015	January 31, 2015	October 31, 2014
Revenue (net of royalties)[1]	$ 1,911,533	$ 1,936,312	$ 1,439,225	$ 1,240,376
Net income (loss)	(5,006,864)[2]	(4,960,489)[3]	(17,665,603)[4]	(5,197,456)[5]
Exploration and evaluation[10]	4,500,103	7,588,046	4,235,900	14,831,197
Property and equipment[10]	24,742,751	23,290,807	22,268,239	18,649,028
Assets held for sale[12]	1,762,845	1,762,845	1,762,845	-
Investment in partnership[11]	18,016,870	18,079,869	16,622,882	19,942,870
Total assets	62,022,939	69,377,154	73,636,191	90,596,919
Loss per share – basic and diluted	(0.06)	(0.06)	(0.20)	(0.06)

	July 31, 2014	April 30, 2014	January 31, 2014	October 31, 2013
Revenue (net of royalties)[1]	$ 1,503,040	$ 2,542,830	$ 2,849,277	$ 1,321,384
Net loss	(1,422,583)[6]	(228,784)[7]	(3,640,635)[8]	(1,898,461)[9]
Exploration and evaluation[10]	2,431,915	1,231,887	1,231,887	1,754,179
Property and equipment[10]	14,479,455	13,376,836	13,665,655	13,786,749
Assets held for sale[12]	9,658,593	10,000,000	10,000,000	15,073,427
Investment in partnership[11]	17,574,581	17,610,141	16,966,553	14,848,099
Total assets	75,509,178	55,237,488	55,148,320	53,485,011
Loss per share – basic and diluted	(0.02)	(0.00)	(0.05)	(0.03)

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 $1,924,390 for depreciation and depletion, $2,655,593 for impairments and $ 719,962 for foreign exchange gain.
3) Net loss during this period includes non-cash deductions of $3,072 for share–based payments, $1,748,331 for depreciation and depletion, $375,516 for impairments and $ 1,460,659 for foreign exchange loss.
4) Net loss during this period includes non-cash deductions of $7,596 for share–based payments, $833,660 for depreciation and depletion, $12,777,376 for impairments and $3,881,852 for foreign exchange gain.
5) Net loss during this period includes non-cash deductions of $29,180 for share–based payments, $1,847,423 for depreciation and depletion, $2,100,760 for impairments and $702,667 for foreign exchange gain.
6) Net loss during this period includes non-cash deductions of $41,219 for share–based payments, $606,883 depreciation and depletion, $(49,471) for impairments and $193,273 for foreign exchange gain.
7) Net loss during this period includes non-cash deductions of $58,732 for share–based payments, $805,087 for depreciation and depletion, $31,006 for impairments and $187,526 for foreign exchange gain.
8) Net loss during this period includes non-cash deductions of $57,639 for share–based payments, $807,538 for depreciation and depletion, $3,747,259 for impairments and $373,196 for foreign exchange gain.
9) Net loss during this period includes non-cash deductions of $64,460 for share–based payments, $665,509 for depreciation and depletion and $564,034 for foreign exchange loss.
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. The Company has recasted comparative information as at January 31, 2014 for the investment in partnership, to present the functional currency of SPLP as USD. As a result the investment in partnership and translation reserve increased by $1,284,633 at January 31, 2015. The recast of comparative information had no impact on cash flows and the results of operations, except for comprehensive loss. The investment arose during the year-end January 31, 2014; accordingly there was no impact to the financial statements for the year ended January 31, 2013.
12) As of January 31, 2014 the Company reclassified costs associated with Cutlass to assets held for sale. At October 31, 2015 the Company reclassified costs associated with Cutlass out of assets held for sale due to a dispute with the project operator over the Company's interest in the property resulting in uncertainty regarding a potential sale. During April 2015 the dispute was settled and the uncertainties were resolved. Accordingly, the Company reclassified the Cutlass property to assets held for sale at January 31, 2015.

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 July 31, 2015, the Company had working capital of $12,582,059 (January 31, 2015 - $25,442,367), which was substantially comprised of cash of $10,434,804, accounts receivable of $1,492,011 less current liabilities of $1,308,026 due within three months of July 31, 2015.

Cash and accounts receivable in the amounts of $4,478,762 and $1,436,081 respectively, represent restricted funds at July 31, 2015, which may only be used to pay expenses and liabilities associated with the development of the Company's STS Olmos Project. Current liabilities associated with the STS Olmos Project were $1,002,281. As a consequence, the Company had unrestricted working capital of $7,669,497 which was substantially comprised of cash of $5,956,042 accounts receivable of $55,930 and assets held for sale of $1,762,845 offset by accounts payable of $305,745.

The Company funded its development activities for the six months ended July 31, 2015 through cash on hand and cash generated from operations. During the period, the Company did not raise any funds from financing activities and used $70,302 related to the modifications of its credit facility as compared to $19,591,834 raised in the period ended July 31, 2014 primarily through the issuance of 12,443,000 common shares in a public stock offering. The Company used $11,580,139 of available cash on investing activities during the period (2014 - $5,318,985).

As at January 31, 2015, the Company was not in compliance with the asset coverage ratio and the leverage ratio covenants pursuant to the agreement. In May 2015, the lender provided the Company a waiver of the non-compliance at January 31, 2015 and for the expected non-compliance for the quarter ending July 31, 2015. In addition the lender agreed to adjust the asset coverage ratio to 5.5 to 1, 4.2 to 1 and 3.6 to 1 at July 31, 2015, October 31, 2015 and January 31, 2016 respectively and to adjust the leverage ratio requirement to .9 to 1, .9 to 1 and .95 to 1 at July 31, 2015, October 31, 2015 and January 31, 2016 respectively As a condition of the waivers granted by the lender, the Company agreed to increase the interest rate margin from 7% to 8% beginning June 1, 2016 and to pledge the assets of Terrace STS as collateral to the Credit Facility. In addition, the Company agreed to reduce the amount available to be drawn under the facility to the $25 million that is currently outstanding. The remaining undrawn amounts under the Credit Facility may be made available to the Company, at the Lender's discretion, depending upon project performance and market conditions. The Company also agreed to advance to Terrace STS, LLC any proceeds received from the sale of the Cutlass oil and gas assets. Finally, the Company also agreed to devise a plan acceptable to the lender to enhance the overall capitalization of the Terrace STS, LLC entity by August 31, 2015. The Company and its financial advisor continue to evaluate financial options and strategic alternatives which would ultimately result in an enhanced capitalization of the Terrace STS, LLC. The Company is in ongoing discussions with its lender to ensure such contemplated plans are satisfactory to the lender.

As at July 31, 2015 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, 2015 – CAD $38,590,000), 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 six months ended July 31, 2015 and 2014.

It is the Company's intention to use its unrestricted working capital to fund the development of the Company's oil and gas properties, other than STS Olmos, (see commitments described under "Exploration and Evaluation") and for general corporate purposes. The Company will use cash on hand and cash flow from operations to continue the development of the STS Olmos Project.

As of the date of this report, the Company has no significant commitments except as described herein (see "Exploration and Evaluation") and in footnote 16 of the Company's condensed consolidated interim financial statements for the six months ended July 31, 2015 and 2014. As noted above, the Company has pledged the assets of Terrace STS as security for its Credit Facility. The Company has not pledged any of its remaining assets as security for loans.

Management of the Company believes with existing working capital, cash expected to be generated from operations, the sale of assets held for resale and because of the preemptive steps it is taking to reduce, defer or layoff onto third parties certain future drilling obligations, if successful, it should have sufficient capital to meet its financial obligations over the next twelve months. There are, however, circumstances beyond the Company's control, which could make it necessary for the Company to seek additional financing (see "Rick Factors") in order to meet its financial obligations.

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:

	2015	**2014**
Short-term compensation		
CEO	$ 180,000	$ 180,000
CFO (current and previous)	147,500	41,546
COO	162,500	162,500
VP Exploration	100,000	100,000
VP Geosciences	100,000	100,000
Secretary	30,909	35,643
Share-based payments	1,536	44,829
	$ 722,445	$ 664,518

As at July 31, 2015:

(a) accounts receivable include advances to key management personnel totalling $47,562 (January 31, 2015 - $47,562) for expenses incurred by the Company on their behalf;
(b) convertible notes held by key management personnel totalled CAD $3,230,000 (2014 - CAD $3,090,000). Interest paid on the convertible notes held by key management personnel and their close family members totalled $128,138 during the period (2014 - $125,576).

Proposed transactions

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

New Accounting Pronouncements

The IASB or IFRIC have issued pronouncements effective for accounting periods beginning on or after January 1, 2015. Only those that may significantly impact the Company are discussed below:

IFRS 9 Financial Instruments (2014)

IFRS 9 contains accounting requirements for financial instruments and replacing IAS 39 Financial Instruments: Recognition and Measurement.

The standard contains requirements in the following areas:

- Classification and measurement. Financial assets are classified by reference to the business model within which they are held and their contractual cash flow characteristics. The 2014 chapter of IFRS 9 introduces a "fair value through other comprehensive income" category for certain debt instruments. Financial liabilities are classified in a similar manner to under IAS 39; however, there are differences in the requirements applying to the measurement of an entity's own credit risk.
- Impairment. The 2014 chapter of IFRS 9 introduces an "expected credit loss" model for the measurement of the impairment of financial assets, so it is no longer necessary for a credit event to have occurred before a credit loss is recognized.
- Hedge accounting. Introduces a new hedge accounting model that is designed to be more closely aligned with how entities undertake risk management activities when hedging financial and non-financial risk exposures.
- Derecognition. The requirements for the derecognition of financial assets and liabilities are carried forward from IAS 39.

Applicable to annual periods beginning on or after January 1, 2018. The Company has not assessed the impact of this pronouncement.

IFRS 15 Revenue from Contracts with Customers

IFRS 15 provides a single, principles based five-step model to be applied to all contracts with customers.

The five steps in the model are as follows:

- Identify the contract with the customer
- Identify the performance obligations in the contract
- Determine the transaction price
- Allocate the transaction price to the performance obligations in the contracts
- Recognize revenue when (or as) the entity satisfies a performance obligation.

Guidance is provided on topics such as the point in which revenue is recognized, accounting for variable consideration, costs of fulfilling and obtaining a contract and various related matters. New disclosures about revenue are also introduced.

IFRS 15 is effective for annual periods beginning January 1, 2017, however on May 19, 2015 the IASB released an exposure draft for comment suggesting deferral of this effective date by one year to January 1, 2018. The Company has not assessed the impact of this pronouncement.

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.

Credit Facility

The terms of the Corporation's Credit Facility contain a number of covenants imposing significant restrictions on the Corporation. The Corporation 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 Credit Facility contains various standard covenants, including financial condition covenants consisting of fiscal quarter end requirements 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 January 31, 2015, the Company was not in compliance with the asset coverage ratio and the leverage ratio covenants pursuant to the agreement. During May 2015, the lender provided the Company a waiver of the non-compliance at January 31, 2015 and for the expected non-compliance for the quarter ending April 30, 2015. In addition, the lender agreed to adjust the asset coverage ratio to 5.5 to 1, 4.2 to 1 and 3.6 to 1 at July 31, 2015, October 31, 2015 and January 31, 2016, respectively, and to adjust the leverage ratio requirement to 0.9 to 1, 0.9 to 1 and 0.95 to 1 at July 31, 2015, October 31, 2015 and January 31, 2016, respectively. As a condition of the waivers and reset of the covenants granted by the lender, the Company agreed to increase the interest rate margin from 7% to 8% beginning June 1, 2016 and to pledge the assets of Terrace STS as collateral to the Credit Facility. The Company also agreed to advance to Terrace STS, LLC any proceeds received from the sale of the Cutlass oil and gas assets. Finally, the Company also agreed to devise a plan acceptable to the lender to enhance the overall capitalization of the Terrace STS, LLC entity by August 31, 2015. The Company and its financial advisor continue to evaluate financial options and strategic alternatives which would ultimately result in an enhanced capitalization of the Terrace STS, LLC. The Company is in ongoing discussions with its lender to ensure such contemplated plans are satisfactory to the lender. There can be no assurance that the Company’s plans to recapitalize Terrace STS, LLC will be acceptable to the lender in accordance with the covenant which could result in a default under the Credit Facility.

If the market continues to deteriorate, the Company may again be deemed to be in noncompliance with the covenants. In the event, the Company is unable to meet the requirements of the covenants contained in the Credit Facility a default could occur. The Company may be forced to sell the STS Olmos asset in order to pay out the Credit Facility or the lender could exercise its rights under the Credit Facility and related agreements which includes foreclosure of the assets of Terrace STS, LLC.

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 assetbacked 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.

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:

	July 31, 2015 (USD)	January 31, 2014 (USD)
Cash	$ 5,730,157	$ 25,251,968
Accounts receivable	-	1,439,871
Operators bond	25,000	25,000
Accounts payable and accrued liabilities	(252,065)	(4,530,587)
Credit facility	-	(25,609,954)
Net	$ 5,503,092	$ (3,423,702)

Based on the above net exposures as at January 31, 2015, a 5% change in the Canadian/US exchange rate would impact the Company's net loss and comprehensive loss by approximately $275,155 (January 31, 2015 - $171,185). The assets and liabilities with exposure to foreign currency risk are those which are denominated in a different currency than the currency determined to the functional currency of the respective entity as of the end of the period.

(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 July 31, 2015, the Company had cash of $10,434,804, accounts receivable of $1,492,011, current liabilities of $1,308,026, amounts outstanding under the Credit Facility of $26,260,540 and convertible notes outstanding totaling CAD $38,590,000. The current liabilities are due within three months of year-end and the Credit Facility and convertible notes mature on May 31, 2018 and April 2, 2018, respectively.

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 July 31, 2015 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, 2015 - CAD $38,590,000), 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 January 31, 2015 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	.89
250,000	250,000	$ 0.19	July 15, 2016	.96
250,000	250,000	$ 0.21	September 16, 2016	1.10
250,000	250,000	$ 0.19	October 18, 2016	1.22
250,000	250,000	$ 0.67	December 16, 2016	1.38
150,000	150,000	$ 1.35	July 8, 2017	1.94
2,800,000	2,800,000			1.05

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 aggregate number of common shares of the Company that may be issued under the plan may not exceed 3,682,182 shares. 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 has issued 1,200,000 RSUs. 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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