JURA ENERGY CORPORATION

MANAGEMENT'S DISCUSSION AND ANALYSIS
FOR THE YEAR ENDED
DECEMBER 31, 2014

March 20, 2015

Introduction

This Management's Discussion and Analysis ("MD&A") is a review of the results of the consolidated operations of Jura Energy Corporation ("JEC" or the "Company") and its subsidiaries Spud Energy Pty Limited ("SEPL"), Frontier Acquisition Company Limited ("FAC") and Frontier Holdings Limited ("FHL") for the years ended December 31, 2014 and 2013 and the Company's financial position as at December 31, 2014. This MD&A is dated and approved by the Board of Directors (the "Board") on March 20, 2015 and should be read in conjunction with the annual audited consolidated financial statements of the Company for the years ended December 31, 2014 and 2013.

The consolidated financial statements of the Company have been prepared by management in accordance with the International Financial Reporting Standards ("IFRS") issued by the International Accounting Standards Board ("IASB") and interpretations issued by the Standing Interpretations Committee of the IASB. The Company uses the United States Dollar as its measurement and reporting currency. All amounts reported in this MD&A are stated in United States Dollars unless otherwise indicated.

JEC is listed on the Toronto Stock Exchange ("TSX") and trades under the symbol of "JEC". Additional information relating to JEC is available on SEDAR at www.sedar.com and Company's website at www.juraenergy.com.

Non IFRS Measures

This MD&A contains the term net revenue per Barrel of Oil Equivalent ("Boe"), production cost per Boe and depletion per Boe to analyze financial and operating performance of producing properties. These benchmarks as presented do not have any standardized meaning prescribed by IFRS and therefore may not be comparable with the calculation of similar measures for other entities.

This MD&A contains the term operating netback to analyze financial and operating performance. This benchmark as presented does not have any standardized meaning prescribed by IFRS and therefore may not be comparable with the calculation of similar measures for other entities. Operating netback is used by research analysts to compare operating performance and the Company's ability to maintain current operations and meet the forecasted capital program. The Company's operating netback is the net result of the Company's revenue (consisting of petroleum and natural gas) net of production costs, excluding depletion of oil and gas properties, as found in the consolidated financial statements of the Company, divided by production for the year.

Boe conversions

The use of the Boe unit of measurement may be misleading, particularly if used in isolation. A Boe conversion ratio of 5.8 thousand cubic feet ("Mcf"):1 Barrel ("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.

Forward-Looking Information

Certain information and statements contained in this MD&A that are not historical facts are forward-looking statements that involve risks and uncertainties. Forward-looking statements include, but are not limited to, operational information, anticipated capital and operating budgets and expenditures, anticipated working capital, estimated costs, sources of financing, the Company's future outlook, expectations regarding the commencement and timing of anticipated commercial production from the Ayesha gas and condensate discovery, development well Badar – 2, Maru East gas discovery and Suri shut-in well; expected pricing under Pakistan Tight Gas (Exploration and Production) Policy, 2011, Pakistan Low Btu Gas Pricing Policy, 2012, Pakistan Petroleum (Exploration and Production) Policy, 2012 and other pricing policies; timing for and drilling results of development wells in the Sara and Reti leases and exploration wells in the Guddu, Badin IV South and Badin IV North exploration licenses; expectations regarding the grant of an exemption by the GoP from the rule permitting revocation of the Sara and Suri leases; and expectations regarding the extension of the Badin IV South and Badin IV North exploration licenses. All statements other than statements of present or historical facts are forward-looking statements. Forward-looking statements typically, but not always, contain words such as "anticipate", "believe", "estimate", "expect", "potential", "could", "forecast", "guidance", "intend", "may", "plan", "predict", "project", "should", "target", "will" or other similar words suggesting future outcomes.

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

Forward-looking statements contained in this MD&A are based on management's current expectations and assumptions regarding future capital and other expenditures (including the amount, nature and sources of funding thereof), future economic conditions, future currency and exchange rates, future international oil prices, continued political stability, timely receipt of any necessary regulatory approvals, timing of the implementation of applicable petroleum exploration and production policies and the Company's continued ability to employ a qualified team to execute work program in a timely and cost efficient manner and the continued participation of the Company's joint venture partners ("JV Partners") in exploration and development activities. In addition, budgets are based upon the Company's current exploration plans and anticipated costs, both of which are subject to changes based on unexpected delays and changes in market conditions.

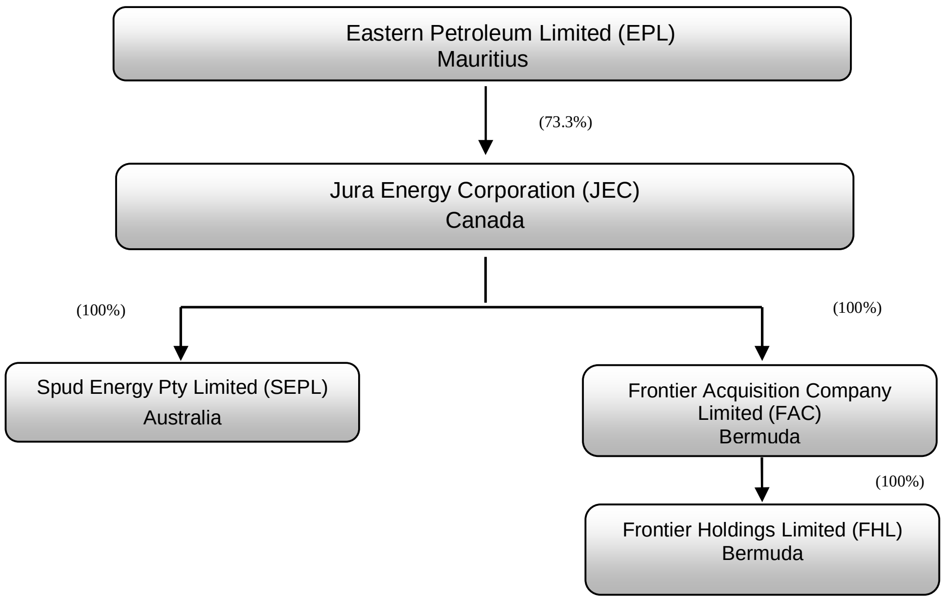
Although management of the Company believes that the expectations and assumptions reflected in such forward-looking statements are reasonable, the Company cautions readers and prospective investors in the Company's securities not to place undue reliance on forward-looking statements as, by their nature, they are based on current expectations regarding future events that involve a number of assumptions, inherent risks and uncertainties which could cause actual results to differ materially from those anticipated by the Company including, but not limited to, those risks as set forth under the heading "Risk Factors". Accordingly, no assurance can be given that any of the events anticipated by the forward-looking statements will transpire or occur or, if any of them do so, what benefits the Company will derive there from. Should one or more of these risks or uncertainties materialize, or should assumptions underlying forward-looking statements prove incorrect, actual results may vary materially from those described in this MD&A as intended, planned, anticipated, believed, estimated, or expected.

The information contained, herein, is made as of March 20, 2015 and, except as required by applicable securities law, the Company does not undertake any obligation to update or to revise any of the included forward-looking statements whether as a result of new information, future events or otherwise. The forward-looking statements contained in this MD&A are expressly qualified by this cautionary statement.

Overview of the Company

JEC is an international upstream oil and gas exploration and production company. The Company's activities are currently conducted in Pakistan, where it has working interests in operated and non-operated exploration, development and producing concessions, through its wholly-owned subsidiaries Spud Energy Pty Limited ("SEPL") and Frontier Holdings Limited ("FHL").

The group structure of the Company is as indicated below:



Background of Oil and Gas Properties

SEPL has one operated and six non-operated working interests in certain exploration licenses and leases in Pakistan which have been granted by the Government of Pakistan ("GoP"). The working interests range from 7.89% to 60%.

FHL has non-operated working interests in two exploration licenses and two development leases (one of which also includes exploration rights in the development and production lease area) in Pakistan. The working interests range from 27.5% to 37.5%.

The following is a summary of the Company's operations in the most recently completed financial year.

Operated Concession

Sara and Suri Leases

SEPL holds a 60.0% working interest in the Sara and Suri leases.

In May 2014, the GoP approved the allocation of gas from the Sara and Suri leases to Central Power Generation Company Limited ("GENCO-II").

The GoP has advised that the following pricing shall apply to the Sara and Suri gas:

- The gas shall be sold to GENCO-II at the gas sales price for the power sector, as determined and notified by the GoP from time to time (the "Power Sector Gas Price"). The current notified Power Sector Gas Price is approximately $4.76 per Million British Thermal Units ("MMBtu").

- The Company will receive a wellhead gas price equal to the lower of:
  i) The Power Sector Gas Price; and
  ii) The price as determined under the GoP's Pakistan Modified Petroleum (Exploration and Production) Policy 1994 (i.e. policy framework from 2000).

The wellhead gas price is therefore expected to be approximately $3.00 per MMBtu, based on the carriage and freight ("C&F") price of a basket of crude oil priced at $55 per Bbl. To the extent the Power Sector Gas Price exceeds the wellhead gas price; the difference will be paid to the GoP as gas development surcharge. Negotiations are in progress with GENCO-II (the "buyer") for the finalisation of a Gas Sale and Purchase Agreement ("GSA"). In March 2015, the GoP approved the Gas Pricing Agreement ("GPA") for Sara and Suri.

In order to exploit the Sui Upper Lime / Sui Main Lime / Basal Ghazij Sand potential and to explore the Ranikot / Parh reservoirs in the Sara lease, the JV Partners have approved the drilling of a development well Sara-4 and the drilling campaign is scheduled to begin in second quarter of 2015.

The Sara and Suri leases are due to expire on July 6, 2016 and June 29, 2015, respectively. Under applicable rules, the GoP may revoke a lease if production has been terminated for more than 90 days, unless such termination is due to force majeure. On January 31, 2014, SEPL applied to the GoP for seeking an exemption from the application of this rule for a period of 15 months with effect from March 21, 2014 up to June 30, 2015. SEPL believes that the exemption will be granted by GoP in the ordinary course.

Non-operated Concessions

Badar Lease

SEPL holds a 7.89% working interest in the Badar lease.

The drilling of development well Badar-2 was commenced in April 2014. In June 2014, Badar-2 well was successfully completed as a gas producer. During a short duration pre-stimulation test on 64/64 inch choke, the well flowed gas at the rate of approximately 13 million cubic feet per day ("MMcf/d") with a wellhead flowing pressure of 697 pounds per square inch ("psi").

The tie-in of development well Badar-2 with the existing pipeline infrastructure has been completed. Production from development well Badar-2 is expected to commence in second quarter of 2015 after gas pricing notification from GoP. Production from the field, after commencement of production from Badar-2, is expected to be approximately18-20 MMcf/d.

The incremental production from the Badar lease is expected to be entitled to a gas price of $4.61 per MMBtu, based on the C&F price of a basket of crude oil priced at $55 per Bbl, under Pakistan Petroleum (Exploration and Production) Policy, 2012 ("Petroleum Policy 2012").

The GoP has approved a five years extension in the Badar lease effective March 14, 2014. The lease will now expire on March 13, 2019.

Zarghun South Lease

SEPL holds a 40.0% working interest in the Zarghun South lease.

The construction of a 64 km gas sale pipeline was completed by the buyer, Sui Southern Gas Company Limited ("SSGCL"), in July 2014. Commercial production from Zarghun South commenced on August 13, 2014, under an interim gas sales arrangement (the "Interim Arrangement") with SSGCL. This Interim Arrangement was approved by the JV Partners pending the installation and commissioning of an Amine Sweetening Unit ("ASU"), used to remove carbon dioxide and hydrogen sulphide from the inlet gas stream. The gas sold during interim period was "off specification", as it did not fully meet the specified composition standard agreed under the GSA with SSGCL and was sold at a discount of 30% to the price that would otherwise be applicable to the specification gas.

All the surface processing facilities including the ASU were successfully commissioned in November 2014, resulting in a significant increase in sales volume from the field. Following full commissioning, gas supplied to SSGCL met the specification requirements provided under the GSA and is no longer being sold at a 30% price discount for "off specification" gas.

Supplemental Zarghun South GSA to incorporate provisions related to supply of tight gas has been submitted to the SSGCL for approval and execution.

The notification of tight and conventional gas prices applicable to the Zarghun South lease by the Oil and Gas Regulatory Authority is expected shortly.

Ayesha Gas Field

FHL holds a 27.5% working interest in the Ayesha gas field.

The drilling of exploration well Ayesha-1, targeting the Upper Sands of the Lower Goru formation, commenced in December 2013. In January 2014, Ayesha-1 achieved the total depth of 2,400 meters. Gas shows were observed over a 50 meter section in the Lower Goru "A" and "B" Sands.

The Ayesha-1 discovery well was completed in the 'B' Sands of the Lower Goru Formation of the Cretaceous age. During a short test on 32/64 inch choke, the well flowed gas with a heating value of approximately 1,000 British Thermal Units per standard cubic feet ("Btu/Scf") at a rate of 11.34 MMcf/d and a wellhead flowing pressure of 1,998 psi. The condensate to gas ratio was in the range of 10-12 barrels per million cubic feet ("Bbl/MMcf").

In July 2014, the GoP approved a gas price for the Ayesha gas field under its "Marginal Gas Pricing Criteria". The expected price for Ayesha gas will be $ 4.86 per MMBtu, based on the C&F price of a basket of crude oil priced at $55 per Bbl.

In September 2014, the GoP approved the declaration of commercial discovery and field development plan of the Ayesha Gas Field and granted a development and production lease ("Ayesha lease") over the discovery area for a period of six years. Ayesha lease covers an area of 19.71 sq. Km and lies in the Badin District of Sindh Province.

Field development activities are in progress and the commencement of commercial production from the Ayesha lease is expected to commence in the fourth quarter of 2015.

Kandra Lease

FHL holds a 37.5% working interest in the Kandra lease**.**

The Kandra gas field development plan was approved by the GoP in January 2006. The plan envisages the partial removal of CO_2 from Kandra shallow gas and the subsequent commingling of this gas with a high Btu gas. The commingled gas would then be used as feedstock for a power station to be constructed nearby. The construction of this facility is a condition of the viability of the plan. The reasons for the delay in developing the Kandra field include a delay in obtaining confirmation of the price at which Kandra gas will be sold, as well as a change in plans from refurbishing the existing plant to constructing a new facility.

The JV Partners are evaluating various options for the optimal field development strategy prior to the commencement of drilling of new wells and completion of existing wells.

The operator has filed a GPA for Kandra gas under the Pakistan Low Btu Gas Pricing Policy, 2012 ("Low Btu Policy") with the GoP for approval. Pursuant to the terms of the GPA, Kandra gas is expected to be entitled to a gas price of $8.75 per MMBtu. The operator of the Kandra gas field is in the process of finalizing a GSA with SSGCL which envisages supply of 40MMcf/d of 300 Btu/Scf gas.

Reti, Maru and Maru South Leases

SEPL holds a 10.66% working interest in the Reti, Maru and Maru South leases.

In January 2013, the GoP approved the sale of gas from the Reti, Maru and Maru South leases to a consortium of four fertilizer companies ("Consortium" or the "buyer"). In March 2013, the JV Partners executed a GSA with the Consortium. Pursuant to the GSA, the buyer laid down a 26 km gas pipeline for supply of gas to Engro Fertilizers Limited.

In connection with the execution of the GSA for the supply of untreated gas, the GoP communicated a provisional price of $6.00 per MMBtu, subject to a quality discount of 10%, in accordance with the Petroleum Policy 2012. However, the GoP issued a clarification in March 2013 that the applicability of the Petroleum Policy 2012 price will be subject to execution of a supplemental Petroleum Concession Agreement.

In June 2013, the Directorate General of Petroleum Concessions ("DGPC") granted Development and Production ("D&P") leases ("Reti-Maru leases") over the Maru South, Reti and Maru discoveries covering an area of 6.64 sq. km, 8.60 sq. km and 15.41 sq. km respectively.

In July 2013, Government Holdings (Private) Limited ("GHPL") exercised its right to increase its working interest in the Reti- Maru leases to 25% pursuant to the Guddu PCA resulting in a reduction of the Company's working interest to 10.66%.

In September 2013, the operator submitted a draft GPA for the Reti-Maru leases to the Director General (Gas) for approval. In December 2013, the GoP advised that Reti-Maru leases are entitled to gas price of $3.45 per MMBtu under the Petroleum Policy 2009 and requested Oil & Gas Development Company Limited to submit a draft GPA in line with the Petroleum Policy 2009 for conversion of regime.

Commercial production from Reti-Maru leases was commenced on December 26, 2013.

Under the terms of the GSA and pending gas price determination by the GoP, the provisional gas price during the interim period will be $5.40 per MMBtu.

In order to exploit the potential of Pirkoh Limestone formation of Eocene age, in February 2014 the JV Partners approved the drilling of the Reti-2 development well. The drilling commenced in February 2015.

Guddu Exploration License

SEPL holds a 13.5% working interest in the Guddu exploration license (subject to reduction to 10.66% upon declaration of commerciality).

The drilling of exploration well Maru East-1 commenced in January 2014. Total depth of 770 meters was achieved in February 2014. During a short duration post-stimulation test on a 32/64 inch choke size, the well flowed gas at a rate of 3.0 MMcf/d with wellhead flowing pressure of 450 psi and a heating value of approximately 700 Btu/Scf.

In September 2014, the GoP approved the Extended Well Testing ("EWT") of Maru East-1 for a period of six months. In March 2015, the GoP allocated the production from Maru East-1 to the existing buyer of Reti-Maru gas (i.e. Engro Fertilizers Limited).

The production from Maru East-1 is expected to be entitled to a gas price of $4.61 per MMBtu, based on the C&F price of a basket of crude oil priced at $55 per Bbl, under Petroleum Policy 2012.

The JV Partners have approved the drilling of another exploratory well Ismail-1 to test the Pirkoh Limestone to the depth of 835 meters. The drilling is expected to commence in third quarter of 2015.

The Guddu exploration license will expire on May 24, 2015.

Zamzama North and Sanjawi Exploration Licenses

Pricing for gas under the Zamzama North and Sanjawi exploration licenses has been deemed converted to pricing under the Petroleum Policy 2012. Accordingly, any gas sales from future discoveries in these licenses will be entitled to a gas price under the Petroleum Policy 2012.

The Zamzama North exploration license reached the end of its initial term on December 14, 2011. The operator is in the process of seeking an extension in the license term up to December 31, 2015.

The operator of the Sanjawi exploration license has applied for a declaration of force majeure, which is the pending approval before the GoP.

Of the Company's 27.0% and 24.0% working interests in Sanjawi and Zamzama North exploration licenses, 16.0% and 12.0%, respectively, are held directly by SEPL and the remaining 11.0% and 12.0%, respectively, are held by Energy Exploration Limited ("EEL") for the benefit of SEPL under the terms of a trust agreement. Pursuant to a share purchase agreement dated December 28, 2011, EEL will become the wholly-owned subsidiary of SEPL upon fulfillment of certain conditions precedent to closing. On closing, EEL will cease to hold these working interests in trust for SEPL.

Badin IV South Exploration License

FHL holds a 27.5% working interest in the Badin IV South exploration license.

In October 2014, the operator on behalf of the working interest owners applied for an eighteen month extension in the third year of Phase-I of the initial term of the exploration license, which FHL believes will be granted in the ordinary course of time.

The drilling of exploration well Haleema-1 commenced in March 2014. The targeted sands within the Lower Goru Formation were encountered close to prognosis. Based on the interpretation of open hole wire line logs, the formations were found to be water bearing. Consequently, the well was plugged and abandoned without testing.

The JV Partners have approved the drilling of two exploration wells Aminah-1 and Ayesha North-1. The drilling campaign is expected to commence in the second quarter of 2015.

Badin IV North Exploration License

FHL holds a 27.5% working interest in the Badin IV North exploration license.

In October 2014, the operator on behalf of the working interest owners applied for an eighteen month extension in the third year of Phase-I of the initial term of the exploration license, which FHL believes will be granted in the ordinary course of time.

The JV Partners have approved the drilling of exploration well Zainab-1. Drilling is expected to commence in the second quarter of 2015.

Performance Overview and Financial Analysis

Operational and Financial Results

Description	December 31,		
	2014	2013	2012
	----------$----------		
Net revenue	2,295,180	447,068	464,632
Gross profit / (loss)	(98,017)	194,342	256,092
Net loss for the year	(3,451,661)	(4,453,267)	(2,282,683)
Loss per share			
- Basic	(0.05)	(0.06)	(0.04)
- Diluted	(0.05)	(0.06)	(0.04)
Capital expenditure	12,002,117	7,155,420	2,502,520
Assets	58,577,647	48,803,211	45,532,889
Long term liabilities	7,208,475	5,314,827	1,698,886
Common shares outstanding at year end			
Basic	69,076,328	69,076,328	59,388,349
Diluted	69,076,328	69,076,328	59,388,349
Cash dividend per share	-	-	-

JEC's revenue in 2014 represents gas sales from the Badar, Reti, Maru and Maru South and Zarghun South gas fields. Commercial production from the Reti, Maru and Maru South and Zarghun South gas field commenced in December 2013 and August 2014 respectively resulting in significant increase in revenue compared to 2012 and 2013.

JEC suffered a net loss of $3,451,661 during 2014, mainly representing cost of production, salaries and other benefits, consultancy, legal and professional services and finance costs on: (i) a loan from its principal shareholder, Eastern Petroleum Limited ("EPL"); (ii) term finance facilities provided by JS Bank Limited; and (iii) the Company's subordinated debentures.

During 2014, JEC incurred significant capital expenditure amounting to $12,002,117. The expenditure mainly related to the development of Zarghun South lease to bring it on-stream, drilling of a development well in the Badar lease and exploration drilling in the Badin IV South and Guddu exploration licenses. No wells were drilled in 2013 and 2012. The expenditure in 2013 and 2012 mainly relates to development of Zarghun South and Reti, Maru and Maru South leases.

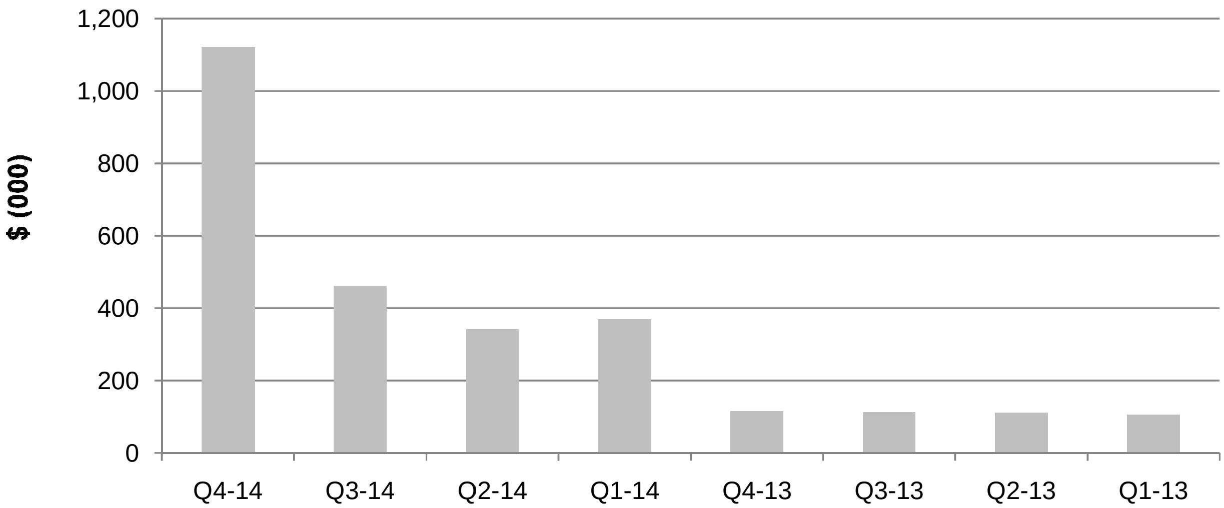
In 2014, long term liabilities of $7,208,475 mainly consisted of asset retirement obligations related to exploration and development properties, the Company's subordinated debentures and the non-current component of term finance facilities from JS Bank Limited. The increase in long term liabilities over the period 2012 to 2014 represents closing of long term debentures in 2013, closing of JS Bank financing facilities in 2014, additions in asset retirement obligation related to drilling of wells and development capital expenditure and an upward revision in net present value of asset retirement obligation in 2014 due to decrease in discount rate.

Fourth Quarter and Summary of Quarterly Results

Description	2014				2013			
	Q-4	Q-3	Q-2	Q-1	Q-4	Q-3	Q-2	Q-1
	---------------------$--------------------							
Revenue	1,122,721	462,126	341,813	368,520	115,440	112,914	112,374	106,340
Net loss from continuing operations	(1,609,670)	(264,412)	(1,104,457)	(473,122)	(2,879,959)	(937,477)	(291,636)	(344,195)
Weighted no. of outstanding share	69,076,328	69,076,328	69,076,328	69,076,328	69,076,328	69,076,328	69,076,328	69,076,328
EPS (basic and diluted)	(0.02)	(0.00)	(0.02)	(0.01)	(0.05)	(0.01)	(0.00)	(0.00)
Capital expenditure	1,807,397	3,915,362	2,380,828	3,898,530	3,273,054	850,366	2,436,608	595,392
Assets	58,577,647	56,916,592	54,293,031	51,716,003	48,803,211	51,142,947	52,214,509	47,704,229
Long term liabilities	7,208,475	5,667,879	5,531,920	5,575,720	5,314,827	5,639,959	5,505,556	1,717,998

Fourth quarter and trend analysis of quarterly information

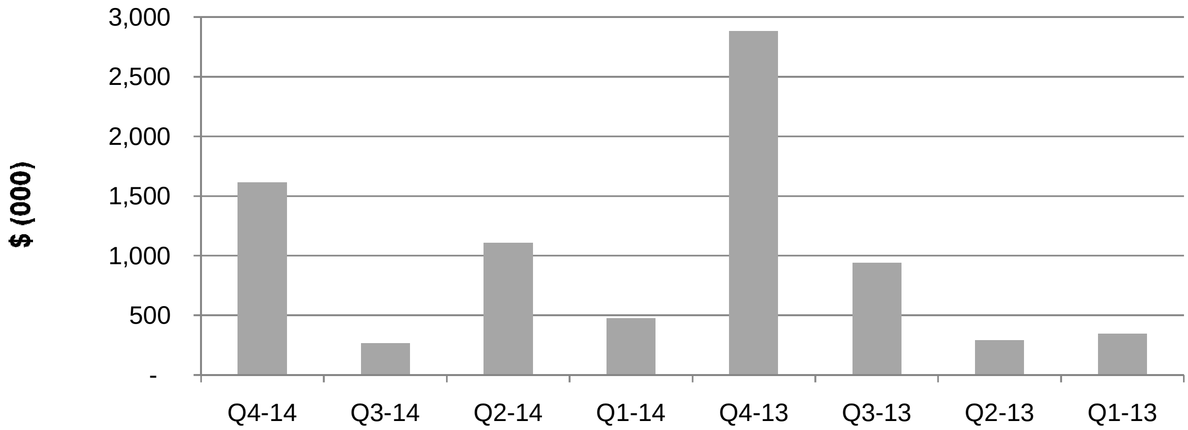
Net Revenue



Quarterly revenue figures indicate a slightly decreasing trend to Q4 2013 due to marginal decline in the daily production rate from the Badar lease. The subsequent significant increase in revenue during 2014 is due to the commencement of commercial production from Reti, Maru and Maru South leases in Guddu block and Zarghun South lease in December 2013 and August 2014, respectively. Revenue in Q2 2014 decreased marginally in comparison to Q1 2014 due to a marginal decrease in production from the Reti, Maru and Maru South leases.

Production from the Badar, Reti, Maru and Maru South leases remained consistent during Q4 2014. The increase in revenue in Q4 2014 in comparison to Q3 2014 represents incremental revenue from the Zarghun South lease after commencement of full scale production in November 2014.

Net loss from continuing operations

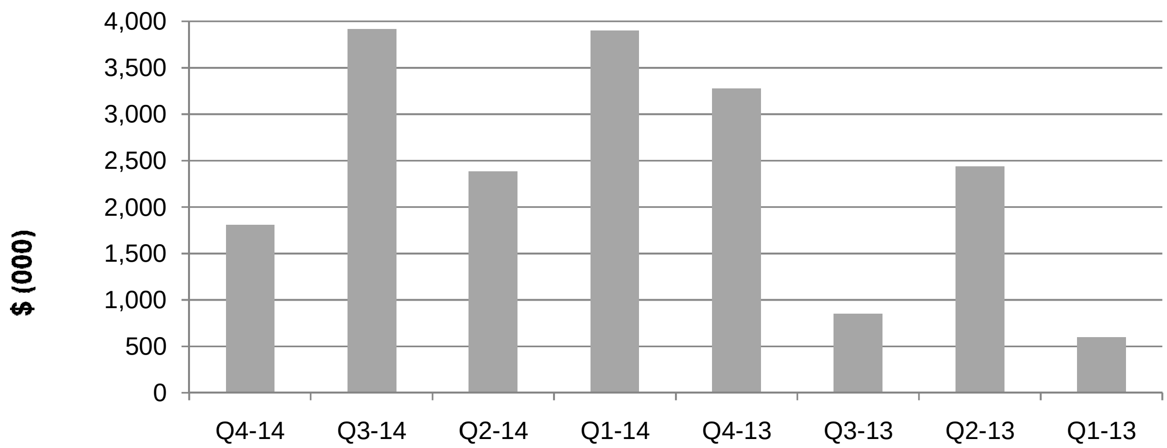


The Company has incurred losses in the current period and its prior fiscal years. Quarterly loss figures indicate consistent losses over the quarters presented, adjusted for a few non-recurring transactions in Q1 2013, Q2 2013, Q4 2013 and Q3 2014.

The Company's net loss from continuing operations in Q4 2014 was $1,609,670 as compared to $264,412 in Q3 2014 and $2,879,959 in Q4 2013. The increase in loss in Q4 2014 in comparison to Q3 2014 is mainly due to additional depletion and production costs related to Zarghun South and finance cost on shareholder loans and JS Bank financing facilities.

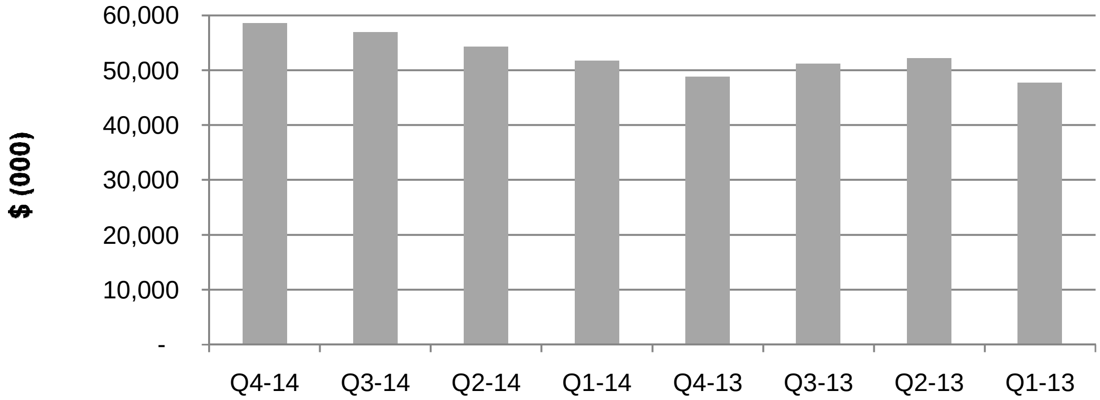
The decrease in loss in Q4 2014 in comparison to Q4 2013 was due to write-offs of exploration costs and receivables from EEL in respect of Sanjawi and Zamzama North exploration licenses in the comparative period as a result of the expiry of the Zamzama North exploration license and the force majeure declaration of Sanjawi exploration license by the operator.

Capital expenditure



The Company continued to incur significant capital expenditure for the development of its oil and gas properties. Capital expenditure incurred in Q4 2013, Q1 2014, Q2 2014 and Q3 2014 primarily relates to the development of Zarghun South lease, Reti, Maru and Maru South leases, Sara and Suri leases and drilling of development well in Badar lease and exploration wells in Badin IV South exploration license and Guddu exploration license.

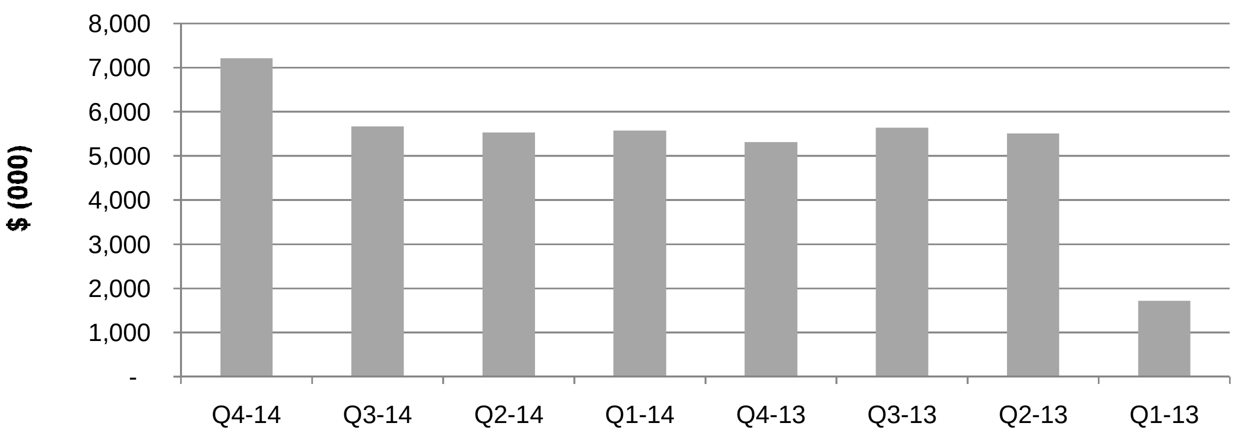
Assets



There is an increasing trend in total assets of the Company. This increase is due to expenditure incurred on the development of the Company's oil and gas properties and drilling of exploration and development wells.

Total assets of the Company at Q4 2014 increased by approximately 3% and 20% in comparison to Q3 2014 and Q4 2013, respectively, due to capital expenditure incurred for the development of the Zarghun South lease and Sara and Suri leases, exploration drilling in the Badin IV South and Guddu licenses and development drilling in the Badar lease.

Long term liabilities



The increase in long term liabilities in Q2 2013, as compared to Q1 2013, represents the issuance of long term subordinated debentures by the Company. There has been no significant change in long term liabilities after Q2 2013 up to Q3 2014. During Q4 2014, the Company closed financing facilities with JS Bank Limited and accrued asset retirement obligation related to processing facilities in the Zarghun South lease, a development well in the Badar lease and exploration discoveries in the Guddu and Badin IV South exploration licenses, resulting in significant increase in long term liabilities.

Financial and Overall Performance Review and Analysis

Review of Financial Results

1. Net loss

Description	For the year ended December 31,		
	2014	2013	Difference
	----------$----------		
Net loss	(3,451,661)	(4,453,267)	1,001,606

The Company posted a loss of $3,451,661 for the year ended December 31, 2014, which is 22% less than the Company's loss for the comparative period.

The Company commenced commercial production from Reti, Maru and Maru South and Zarghun South leases in December 2013 and August 2014, respectively, resulting in significant increase in net revenue for the current year offset by production costs and depletion of capitalized costs. However, the decrease in loss is mainly due to write offs of exploration and evaluation costs and amounts receivable from EEL related to the Sanjawi and Zamzama North exploration licenses in the comparative period.

Segment breakdown of loss for the year ended December 31, 2014 is as follows:

	$
Canada	(1,138,411)
Pakistan	(2,313,250)

The loss for the year is mainly attributable to the following:

- Canada segment is non-revenue generative. Loss in Canada mainly represents corporate expenses and finance cost on the Company's subordinated debentures.

- Net loss of Pakistan segment mainly represents production costs, depletion of producing properties, finance costs on shareholder loans and JS Bank Limited financing facilities, salaries and other benefits and other administrative costs net-off by revenue from the Badar, Reti, Maru and Maru South and Zarghun South leases and gain on retranslation of shareholder loans at reporting date exchange rate.

2. Net revenue

Description	For the year ended December 31,		
	2014	2013	Difference
	-----------$----------		
Sales	2,617,385	495,099	2,122,286
Royalty	(322,205)	(48,031)	(274,174)
Net revenue	2,295,180	447,068	1,848,112

Net revenue represents sale of gaseous hydrocarbons from the Badar, Reti, Maru and Maru South and Zarghun South leases net of royalty.

The increase of $2,122,286 in revenue compared to the comparative period is due to the revenue from Reti, Maru and Maru South and Zarghun South leases that commenced production in December 2013 and August 2014, respectively.

During the year ended December 31, 2014 daily gas sales volumes from the Badar gas field and Reti, Maru and Maru South gas fields averaged approximately 11.76 MMcf and 10.54 MMcf respectively. Average daily sales volume from Zarghun South since August 2014 was 2.92 MMcf.

Gross production volume and price trends for the years presented are as follows:

Description	For the year ended December 31,		
	2014	2013	Difference
Production in Boe	202,581	63,231	139,350
Price ($ / Boe)[1]	12.92	7.83	5.09

[1]*Refer to non IFRS measures.*

The significant increase in price per Boe is due to higher prices of production from the Reti, Maru and Maru South and Zarghun South leases compared the price obtained by the Company for the Badar gas.

The royalty is calculated at 12.5% of revenue minus gathering, processing and transportation charges, in the case of the Badar lease, and 12.5% of value of petroleum for the Reti, Maru and Maru South and Zarghun South leases.

The trend in royalty costs per Boe for the periods presented is as follows:

Description	For the year ended December 31,		
	2014	2013	Difference
Production in Boe	202,581	63,231	139,350
Royalty ($ / Boe)[1]	1.59	0.76	0.83

[1]*Refer to non IFRS measures.*

The historical effective rate of royalty for the Badar lease is approximately 9.5% of the value of petroleum compared to 12.5% of the value of petroleum for the Reti, Maru and Maru South and Zarghun South leases. During 2014, production from the Badar lease comprised 29% of Jura's share of production compared to 99.5% in the comparative period. This resulted in significant increase in royalty per Boe for the current year.

3. Cost of production

Description	For the year ended December 31,		
	2014	2013	Difference
	----------$----------		
Production costs	1,096,703	214,073	882,630
Depletion of oil and gas properties	1,296,494	38,653	1,257,841
	2,393,197	252,726	2,140,471

Comparative production and production cost per Boe for the periods presented are as follows:

Description	For the year ended December 31,		
	2014	2013	Difference
Production in Boe	202,581	63,231	139,350
Production costs ($ / Boe)[1]	5.41	3.39	2.02

[1]*Refer to non IFRS measures.*

Significant increase in production cost per Boe from 2013 to 2014 represents high production costs associated with the Reti, Maru and Maru South and Zarghun South leases that commenced production in December 2013 and August 2014, respectively.

Comparative depletion cost per Boe for the periods presented are as follows:

Description	For the year ended December 31,		
	2014	2013	Difference
Production in Boe	202,581	63,231	139,350
Depletion costs ($ / Boe)[1]	6.40	0.61	5.45

[1]*Refer to non IFRS measures.*

Depletion cost per Boe increased significantly during the year in comparison with the comparative period due to additional depletion costs related to the Reti, Maru and Maru South and Zarghun South leases.

4. Administrative expenses

Description	For the year ended December 31,		
	2014	2013	Difference
	----------$----------		
Administrative expenses	2,611,164	3,762,554	(1,151,390)

Segment breakdown of administrative expenses for the year ended December 31, 2014 is as follows:

	$
Canada	654,434
Pakistan	1,956,730

The decrease of $1,151,390 in administrative expenses from 2013 to 2014 is mainly due to provision for impairment of receivable from EEL recorded in the comparative period and decease in administrative expenses on account of operational efficiency.

5. Finance income

Description	For the year ended December 31,		
	2014	2013	Difference
	----------$----------		
Finance income	**593,369**	**283,070**	**310,299**

Finance income mainly represents foreign exchange gain on retranslation of shareholder's loan to SEPL at the reporting date exchange rate due to the strengthening of US$ to C$ exchange rate parity.

6. Finance costs

Description	For the year ended December 31,		
	2014	2013	Difference
	----------$----------		
Interest on borrowings	720,349	325,473	394,876
Accretion on asset retirement obligation	67,846	76,449	(8,603)
Finance costs others	492,974	37,500	455,474
	1,281,169	**439,422**	**841,747**

Finance costs increased significantly during the year compared to comparative period. This is mainly due to an increase in amortised cost of shareholder's loan and mark up on the JS Bank Limited financing completed during the year. Further, the Company's subordinated debentures were issued on May 27, 2013; therefore comparative period include interest on debentures for seven months only compared to the complete twelve months in the current year. Finance costs others mainly represents the additional sum charged by the operator of the Zarghun South lease due to a delay in payment of cash calls.

7. Operating netback

Description	For the year ended December 31,		
	2014	2013	Difference
	---------$----------		
Net revenue	2,295,181	447,068	1,848,113
Production costs	(1,096,703)	(214,073)	(882,630)
Operating netback	**1,198,478**	**232,995**	**965,483**
Production in Boe	202,581	63,231	139,350
Operating Netback ($ / Boe)[1]	5.92	3.68	2.24

[1]*Refer to non IFRS measures.*

Operating netback per Boe for the year ended December 31, 2014 increased by $2.24 compared to the comparative year. This is mainly due higher average realized price for production from the Reti, Maru and Maru South and Zarghun South leases.

Provisions, contingencies and commitments

Provision for pricing matter – Reti, Maru and Maru South Leases

In January 2013, the GoP approved the sale of gas from the Reti, Maru and Maru South leases to a consortium of four fertilizer companies ("the Consortium" or the "buyer"). On March 15, 2013, the JV Partners executed a GSA with the Consortium. Pursuant to the GSA, the buyer laid down a 26 km gas pipeline for supply of gas to Engro Fertilizers Limited.

Further to the execution of the GSA for the supply of untreated gas, the GoP communicated a provisional price of $6.00 per MMBtu, subject to a quality discount of 10%, in accordance with Petroleum Policy 2012. However, the GoP issued a clarification in March 2013 that the applicability of Petroleum Policy 2012 price will be subject to execution of a supplemental Petroleum Concession Agreement.

On September 16, 2013, the operator submitted a draft GPA for the Reti, Maru and Maru South leases to the Director General (Gas) for approval. However, pursuant to the amendments in the Petroleum Policy 2012, Director General (Gas) intimated that Reti, Maru and Maru South gas discoveries qualify for the conversion price of $3.45 per MMBtu under Pakistan Petroleum (Exploration and Production) Policy, 2009.

The commercial production from Reti, Maru and Maru South leases was commenced on December 26, 2013. Under the terms of the GSA and pending gas price determination by the GoP, the provisional gas price will be $6.00 per MMBtu subject to a quality discount of 10%.

The JV Partners have taken up the matter with the Ministry of Petroleum and Natural Resources; however, until the resolution of the pricing matter, revenue from the Reti, Maru and Maru South gas fields has been recorded by the management based on a price of $3.45 per MMBtu and the excess receipts have been recorded as deferred revenue. As at December 31, 2014, the Company has received an excess amount of $830,329 from the buyer.

Contingencies and Commitments

The following table summarizes the guarantees issued by the bank on behalf of the Company GoP representing 50% of minimum financial obligations under the Company's exploration licenses.

Description	December 31, 2014	December 31, 2013
	--------$--------	
Exploration license for Guddu block No 2869-9	-	-
Exploration license for Zamzama North Block 2667-8	-	-
Exploration license for Sanjawi Block 3068-2	-	-
Exploration license for Badin IV North Block	-	192,500
Exploration license for Badin IV South Block	-	819,867
Exploration license for Salam Block	-	79,688
Exploration license for Mirpur Mathelo Block	-	89,375
	-	**1,181,430**

The guarantees issued to the GoP have been expired. The Company has initiated the process to hypothecate Kandra reserves in lieu of bank guarantees. The hypothecation will result in GoP's lien on Kandra reserves to the extent of 100% of minimum financial obligations.

Financial Commitments

The Company's financial commitments mainly consist of minimum work commitments related to its exploration licenses, approved authority for expenditures and commitments under non-cancellable operating leases for employee vehicles.

The following table summarizes the financial commitments of the Company as at December 31, 2014 and 2013. These financial commitments are expected to be funded through internal cash generation and debt and/or equity financing.

Description	December 31,2014	December 31, 2013
	-------$-------	
Minimum capital commitments related to exploration licenses	4,419,050[1]	4,800,500
Commitments under approved AFEs	1,767,285	4,146,219
Commitment under share purchase agreement for the acquisition of EEL	1,000	1,000
Commitment under operating leases		
- Not later than one year	103,521	80,781
- Later than one year and less than five years	92,258	89,315
Total	**6,383,114**	**9,117,815**

[1]Breakdown of minimum capital commitments related to exploration licenses per year:

Description	2015	2016	2017	Total
	-------$------			
Sanjawi	668,250	94,500	1,755,000	2,517,750
Zamzama North	1,224,000	-	-	1,224,000
Guddu	319,800	-	-	319,800
Badin IV North	357,500	-	-	357,500
Total	**2,569,550**	**94,500**	**1,755,000**	**4,419,050**

Going Concern and Liquidity

At December 31, 2014, the Company had current assets of $2.33 million comprising trade and other receivables of $2.18 million and cash and cash equivalents of $0.15 million. Total current liabilities were $19.82 million comprising account payable and accrued liabilities of $6.68 million and borrowings of $13.14 million. In addition to its ongoing working capital requirements, the Company also had financial commitments as at December 31, 2014 that amounted to $6.4 million. Additional cash resources will be required to exploit the Company's petroleum and natural gas properties. These material uncertainties raise significant doubt as to the Company's ability to continue as a going concern and, accordingly, the appropriateness of the use of accounting principles applicable to a going concern. The uncertainty includes the need for additional cash resources to fund its existing operations and for the development of its properties, economic dependence on JV Partners and the current economic and political conditions in Pakistan.

To date, all exploration, development and other operational activities of the Company have been funded by the internal cash generation from its producing concession, equity and debt issuances, funding by a shareholder, and by farm-out through which a third party reimbursed the Company for a portion of its historical costs and will pay a portion of the Company's future capital expenditures to earn a portion of the Company's working interest in its properties.

On February 20, 2013, SEPL entered into an unsecured bridge loan financing arrangement of C$ 11 million with its majority shareholder, Eastern Petroleum Limited ("EPL"). The loan carries interest at the rate of 3 months US$ LIBOR + 4%. Further, EPL also has a right to convert each C$ 1 of outstanding principal and accrued interest thereon into one common share of the Company. As at December 31, 2014, the Company had utilized C$ 9.2 million under this financing arrangement. The loan is due for repayment on demand after February 20, 2015 ("the maturity date"). However, EPL has provided an undertaking to the Company, pursuant to which, EPL shall not demand repayment of the principal amount and accrued interest thereon after the maturity date, unless the Company has sufficient funds to repay, in EPL's reasonable judgment, or the Company closes a qualifying financing.

On November 7, 2014, SEPL entered into two financing facilities totalling PKR 400 million (equivalent $3.9 million) with JS Bank Limited, a related party. These facilities carry interest at the rate of 3 months Karachi Inter Bank Offered Rate ("KIBOR") plus 2% payable quarterly in arrears.

Management is currently evaluating and pursuing other funding alternatives, including debt financing and new equity issuances to fund the Company's ongoing operations. The Company's access to sufficient capital will impact its ability to complete its planned exploration and development activities. However, there can be no assurance that the steps management is taking will be successful.

These financial statements do not reflect the adjustments to the carrying values of assets and liabilities and the reported revenues and expenses and balance sheet classifications that would be necessary if the Company was unable to realize its assets and settle its liabilities as a going concern in the normal course of operations. Such adjustments could be material.

Stock Based Compensation

The Company has a share option plan pursuant to which options may be granted to directors, officers, and employees of the Company. The options generally vest over a period of up to three years and expire no more than five years from the date of grant.

On April 16, 2013, the Company granted 1,765,764 options with an exercise price of C$1 for each option to its directors and officers. The weighted average fair value of stock options granted was $0.11 per stock option as at April 16, 2013, calculated using the Black Scholes Option Pricing Model.

The assumptions used in the calculations are:	**April 16, 2013**
Risk-free interest rate (%)	1.02
Expected life (years)	4.95
Estimated volatility of underlying common shares (%)	70.00
Forfeiture rate (%)	0.00

	Year ended December 31, 2014		**Year ended December 31, 2013**	
	Number of options	**Weighted average exercise price**	**Number of options**	**Weighted average exercise price**
Options outstanding, beginning of period	2,943,294	C$ 0.79	1,177,530	C$ 0.48
Granted	-	-	1,765,764	C$ 1.00
Exercised	-	-	-	-
Forfeited	-	-	-	-
Expired	(575,000)	C$ 0.60	-	-
Options outstanding, end of period	2,368,294	C$ 0.84	2,943,294	C$ 0.79
Options exercisable, end of period	1,813,042	C$ 0.79	1,766,119	C$ 0.65

Price	**Number outstanding**	**Weighted average remaining contractual life (years)**	**Exercisable**
C$ 0.109	1,665,764	3.24	1,110,512
C$ 0.145	487,500	0.97	487,500
C$ 0.232	215,030	0.97	215,030
C$ 0.109 – C$ 0.232	2,368,294	2.57	1,813,042

Shares Based Compensation

During the year ended December 31, 2014 stock-based compensation of $40,601 (December 31, 2013: $283,151) was charged to the consolidated statement of comprehensive loss. Of $40,601 (December 31, 2013: $283,151), $40,601 (December 31, 2013: $132,913) represents stock options issued to the directors and officers of the Company and Nil (December 31, 2013: $150,238) represents shares based compensation of the interim CEO granted by the ultimate shareholder.

Results of Operations

The following table summarizes the working capital of the Company as at December 31, 2014 as compared to December 31, 2013:

Description	**As at December 31, 2014**	**As at December 31, 2013**
	----------$-----------	
Current assets	2,336,219	1,992,378
Current liabilities	(19,819,007)	(8,527,159)
Working capital deficiency	(17,482,788)	(6,534,781)

The working capital deficiency reflects amounts due to EPL on demand following maturity of a shareholder loan on February, 20, 2015 amounting to $10,284,720. However, EPL has undertaken not to demand repayment of the loan until closing of a debt or equity financing by the Company or the Company having sufficient liquidity to repay the loan on the maturity date, see "Going Concern and Liquidity" above. All other liabilities are expected to be settled through internal cash generation from the Badar, Reti, Maru, Maru South and Zarghun South leases and new debt and/or equity financing.

Contractual Obligations

The following table sets forth the contractual obligations of the Company as at December 31, 2014:

Description	Payments due by period			
	Total	Less than 1 year	1-5 years	After 5 years
	----------$-----------			
Minimum capital commitments related to exploration licenses[1]	4,419,050	2,569,550	1,849,500	-
Commitments under outstanding AFEs	1,767,285	1,767,285	-	-
Operating leases	195,779	103,521	92,258	-
Purchase obligations[2]	1,000	1,000	-	-
Other obligations[3]	27,027,482	19,819,007	4,833,505	2,374,970
Total contractual obligations	**33,410,596**	**24,260,363**	**6,775,263**	**2,374,970**

Notes:

(1) "Obligations related to exploration licenses" means the obligations which are legally binding on the Company pursuant to the terms of the relevant Petroleum Concession Agreement.

(2) "Purchase obligation" means a binding sale and purchase agreement entered into by the Company with respect to the acquisition of EEL that specifies all significant terms related thereto, and the timing of the transaction.

(3) "Other obligations" means other financial liabilities reflected in the Company's statement of financial position.

Off-Balance Sheet Arrangements

JEC did not have any off-balance sheet arrangements as at December 31, 2014.

Transactions with Related Parties

The Company's related parties with significant transactions during the year include its majority shareholder, EPL, JS Bank Limited, an associated entity and key management personnel. Details of transactions with related parties are as follows:

Transaction with majority shareholder

EPL, which is a majority shareholder of JEC, provided financial support to SEPL in the form of a non-interest bearing loan payable on demand and an interest bearing bridge loan financing to meet its financial commitments. The interest bearing bridge loan carries interest at the rate of US dollar LIBOR + 4% compounded quarterly. The changes in loan balance during the applicable periods and balances outstanding as at December 31, 2014 and December 31, 2013 are as follows:

Description	December 31, 2014	December 31, 2013
	----------$-----------	
Balance payable at beginning of the year	7,952,646	2,389,777
Loan received during the year net of embedded derivative	3,057,514	5,410,727
Loan repaid during the year	(500,000)	-
Interest accrued on loan from shareholder	390,935	443,356
Exchange gain on retranslation of shareholder loan	(608,869)	(276,956)
Amount paid on behalf of EPL during the year	(7,506)	(14,258)
Balance payable at end of the year	**10,284,720**	**7,952,646**

Transaction with associated entity – JS Bank Limited

On November 7, 2014, SEPL entered into two financing facilities totalling PKR 400 million (equivalent $3.9 million) with JS Bank Limited, a related party controlled by Mr. Jahangir Siddiqui (who also controls EPL). These facilities carry interest at the rate of 3 months KIBOR plus 2% payable quarterly in arrears.

Description	December 31, 2014	December 31, 2013
	----------$----------	
Balance payable at beginning of the year	-	-
Loan received during the year	3,717,218	-
Interest accrued	50,223	-
Exchange loss on retranslation of loan	66,064	-
Balance payable at end of the year	**3,833,505**	-

Key management personnel

Description	December 31, 2014	December 31, 2013
	----------$----------	
Management salaries and benefits	354,150	652,380
Management stock based compensation	8,669	172,819
Directors' fees and compensation	151,575	462,002
Total	**514,394**	**1,287,201**

Future Outlook

The Company's capital expenditure program for 2015 includes:

- tie-in of Badar-2 with the existing pipeline infrastructure;
- development of Ayesha gas and condensate discovery involving installation of production facility;
- installation of front end compression facility at Suri shut-in wells;
- drilling of development well in Reti lease;
- drilling of development well in Sara lease;
- drilling of two exploration wells in Badin IV South license; and
- drilling of one exploration well in Badin IV North license.

This capital expenditure program is expected to be funded through available cash, bridge loan financing with EPL, internal cash generation and new debt and/or equity financing.

In the near future, the Company expects the commencement of commercial production from the following:

- Development well Badar-2 in Badar lease;
- Maru East gas discovery in Guddu exploration license;
- Sara and Suri leases; and
- Ayesha gas and condensate discovery in Badin IV South exploration license.

As of the date of this MD&A, the tie-in of Badar-2 with the existing pipeline infrastructure has been completed and drilling of development well in Reti lease has commenced.

Impact of decline in International oil prices on wellhead gas prices in Pakistan

In Pakistan, the price for gas purchased by the GoP is based on a formula and linked to the international prices for a basket of imported Arabian and Persian Gulf crude oil ("Basket of Crude"). Prices are based upon a baseline of 1,000 Btu/Scf. If the gas which is sold has a Btu content which is less than or greater than 1,000 Btu/Scf, the price is proportionately decreased or increased, respectively.

The wellhead gas price in Pakistan is determined by applying step up discounting using various slabs under the different applicable petroleum policies to the C&F price of the Basket of Crude. The basket will reflect the actual mix of imported crude oils in the previous six months (January to June and July to December) in Pakistan as notified by the Ministry of Petroleum and Natural Resources, Government of Pakistan. Each discounting table under a policy has a predetermined C&F floor and ceiling price. The discount table is designed to provide maximum benefit to the seller for a lower C&F price. As the C&F price increases the applicable discount also increases until the C&F price reaches the ceiling price. The discounts applicable to the C&F price under various slabs range from 0% to 90%. No benefit is provided to the seller if the C&F price is higher than the ceiling price. The applicable floor and ceiling prices vary for each petroleum policy.

As a result of the formula used for calculating the price for gas purchased by the GoP, decreases in international oil prices do not proportionately reduce the price for gas purchased by the GoP. For example, a 40% reduction in international crude oil pricing from $100/Bbl to $60/Bbl will result in only a 17% decrease in the price for gas purchased by the GoP. Petroleum Policy, 2012 has the highest ceiling price and, accordingly, gas prices under this policy are the most impacted by a reduction in international oil prices. The applicability of particular petroleum policy to wellhead gas pricing for a discovery depends upon timing of drilling and commencement of production from the discovery area.

New Accounting Standards and Pronouncements

New and amended standards adopted by the Company

The following standards have been adopted by the Company for the first time for the financial year beginning on or after January 1, 2014 and may have a material impact on the Company:

Amendment to International Accounting Standard ("IAS") 32, 'Financial instruments: Presentation' on offsetting financial assets and financial liabilities. This amendment clarifies that the right of set-off must not be contingent on a future event. It must also be legally enforceable for all counterparties in the normal course of business, as well as in the event of default, insolvency or bankruptcy. The amendment also considers settlement mechanisms. The amendment did not have a significant effect on the Company financial statements.

Amendment to IAS 39, 'Financial instruments: Recognition and measurement' on the novation of derivatives and the continuation of hedge accounting. This amendment considers legislative changes to 'over-the-counter' derivatives and the establishment of central counterparties. Under IAS

39 novation of derivatives to central counterparties would result in discontinuance of hedge accounting. The amendment provides relief from discontinuing hedge accounting when novation of a hedging instrument meets specified criteria. The Company has applied the amendment and there has been no significant impact on the Company financial statements as a result.

International Financial Reporting Interpretations Committee ("IFRIC") 21, 'Levies', sets out the accounting for an obligation to pay a levy if that liability is within the scope of IAS 37 'Provisions'. The interpretation addresses what the obligating event is that gives rise to pay a levy and when a liability should be recognized. The Company assessed the implication of IFRIC 21 at January 1, 2014 and determined that adoption of IFRIC 21 did not result in any change in the accounting of levies by the Company.

Other standards, amendments and interpretations which are effective for the financial year beginning on January 1, 2014 are not material to the Company.

New standards, amendments and interpretations not yet adopted

A number of new standards and amendments to standards and interpretations are effective for annual periods beginning after January 1, 2014, and have not been applied in preparing the Company's consolidated financial statements. None of these is expected to have a significant effect on the consolidated financial statements of the Company, except the following set out below:

IFRS 9, 'Financial instruments', addresses the classification, measurement and recognition of financial assets and financial liabilities. The complete version of IFRS 9 was issued in July 2014. It replaces the guidance in IAS 39 that relates to the classification and measurement of financial instruments. IFRS 9 retains but simplifies the mixed measurement model and establishes three primary measurement categories for financial assets: amortized cost, fair value through other comprehensive income and fair value through profit or loss. The basis of classification depends on the entity's business model and the contractual cash flow characteristics of the financial asset. Investments in equity instruments are required to be measured at fair value through profit or loss with the irrevocable option at inception to present changes in fair value in other comprehensive income not recycling. There is now a new expected credit losses model that replaces the incurred loss impairment model used in IAS 39. For financial liabilities there were no changes to classification and measurement except for the recognition of changes in own credit risk in other comprehensive income, for liabilities designated at fair value through profit or loss. IFRS 9 relaxes the requirements for hedge effectiveness by replacing the bright line hedge effectiveness tests. It requires an economic relationship between the hedged item and hedging instrument and for the 'hedged ratio' to be the same as the one management actually use for risk management purposes. Contemporaneous documentation is still required but is different to that currently prepared under IAS 39. The standard is effective for accounting periods beginning on or after January 1, 2018. Early adoption is permitted. The Company is yet to assess IFRS 9's full impact.

IFRS 15, 'Revenue from contracts with customers' deals with revenue recognition and establishes principles for reporting useful information to users of financial statements about the nature, amount, timing and uncertainty of revenue and cash flows arising from an entity's contracts with customers. Revenue is recognized when a customer obtains control of a good or service and thus has the ability to direct the use and obtain the benefits from the good or service. The standard replaces IAS 18 'Revenue' and IAS 11 'Construction contracts' and related interpretations. The standard is effective for annual periods beginning on or after January 1, 2017 and earlier application is permitted. The Company is assessing the impact of IFRS 15.

Change in accounting estimate

Effective July 1, 2014, the Company changed its estimates of the useful lives of its producing fields determined by reference to the proved and probable reserves and taking into account future development expenditure necessary to bring those reserves into production to better reflect the estimated periods during which these fields will remain in production. Proved and probable reserves and future development costs are estimated on the basis of reserves certification carried out by an independent expert. The estimated useful lives of the producing fields were previously determined by reference to the proved developed producing reserves.

The effect of this change in estimate was a reduction of depletion expense and net loss by $720,472 for the year ended December 31, 2014. As at December 31, 2014 it is impracticable for the Company to determine the impact of this change in accounting estimate on future periods.

Reclassifications in the financial statements

i. During the year the Company performed a review of its financial statements and reclassified expenses from nature to function classification within the statement of comprehensive loss on the basis that, the classification by function is considered to be more relevant to users. Comparatives balances have been reclassified to ensure consistency with the current year. The impact of the reclassification by line item is shown in the tables below:

Classification of expenses by nature (as previously reported)	**December 31, 2014 $**	**December 31, 2013 $**
Finance income	-	2,037
Production costs	(1,096,703)	(214,073)
Salaries and other benefits	(1,030,145)	(1,026,999)
Directors' fees and compensation	(151,575)	(462,002)
Depletion, depreciation and amortization	(1,347,115)	(85,802)
Exploration and evaluation costs written off	(62,170)	(1,208,108)
Provision for impairment of receivable from EEL	-	(818,218)
Legal and professional charges	(462,846)	(415,872)
Travelling expenses	(138,126)	(249,377)
Finance costs	(1,281,169)	(439,422)
Consultancy charges	(373,320)	(321,643)
Office rent and utilities	(191,943)	(161,440)
Fees and subscriptions	(50,286)	(118,688)
Other expenses	(162,302)	(141,166)
Foreign exchange gain	593,369	283,070
Gain on fair valuation of embedded derivatives	7,490	339,273
Gain on settlement of dispute with JV operator	-	138,095
Total expenses	**(5,746,841)**	**(4,900,335)**
Classification of expenses by function (as restated)		
Cost of production	(2,393,197)	(252,726)
Administrative expenses	(2,611,164)	(3,762,554)
Exploration and evaluation costs written off	(62,170)	(1,208,108)
Other income	7,490	479,405
Finance income	593,369	283,070
Finance costs	(1,281,169)	(439,422)
Total expenses	**(5,746,841)**	**(4,900,335)**

ii. Certain amounts in prior year have been reclassified to conform to the current year's presentation. Other than the items reclassified above, changes in accounts payable and accrued liabilities, related to capital expenditure, amounting to $ 1,982,824, are presented on a net basis with Property plant and equipment expenditure, in the statement of cash flows, rather than such changes being presented as part of changes in working capital. This change in classification does not materially affect previously reported net cash flows used in operating and investing activities in the Consolidated Statement of Cash Flows, and had no effect on the previously reported Consolidated Statement of Financial Position and Consolidated Statement Comprehensive Loss.

Critical Accounting Estimates and Judgments

Estimates and judgements are continually evaluated and are based on historical experience and other factors, including expectations of future events that are believed to be reasonable under the circumstances.

Critical accounting estimates and assumptions

The Company makes estimates and assumptions concerning the future. The resulting accounting estimates will, by definition, seldom equal to the related actual results. The estimates and assumptions that have a significant risk of causing a material adjustment to the carrying amounts of assets and liabilities within the next financial year are addressed below:

a) *Exploration and evaluation expenditure*

The Company's accounting policy for exploration and evaluation expenditure results in certain items of expenditure being capitalized for an area of interest where it is considered likely to be recoverable by future exploitation or sale or where the activities have not reached a stage which permits a reasonable assessment of the existence of reserves. This policy requires management to make certain estimates and assumptions as to future events and circumstances, in particular whether an economically viable extraction operation can be established. Any such estimates and assumptions may change as new information becomes available. If, after having capitalized the expenditure under the policy, a judgment is made that recovery of the expenditure is unlikely, the relevant capitalized amount is written off to the statement of comprehensive income / (loss).

b) *Estimated impairment of oil and gas properties*

Oil and gas reserves are an important element in impairment testing for oil and gas properties. Estimates of oil and gas reserves are inherently imprecise and are subject to future revision. These reserves are estimated by an independent expert with reference to available reservoir and well information, including production and pressure trends for producing reservoirs and, in some cases, subject to definitional limits, to similar data from other producing reservoirs.

The recoverable amount of a cash generating unit ("CGU") and an individual asset is determined based on the higher of the value-in-use calculations and fair value less costs to sell. These calculations require the use of estimates and assumptions, including the discount rate. It is reasonably possible that the commodity price assumptions may change, which may impact the estimated life of the field and economical reserves recoverable and may require a material adjustment to the carrying value of oil and gas properties. The Company monitors internal and external indicators of impairment relating to its assets.

c) *Estimated oil and gas reserves used for depletion of oil and gas properties*

Proved and probable reserves, used for recording depletion of oil and gas properties, are estimated by an independent expert with reference to available reservoir and well information. Proved and probable reserves estimates are subject to revision, either upward or downward, based on new information, such as from development drilling and production activities or from changes in economic factors, including product prices, contract terms or development plans. Changes to the estimates of proved and probable reserves, affect the amount of depletion recorded in the financial statements for oil and gas properties related to hydrocarbon production activities.

d) *Asset retirement obligation*

Estimates of the amount of provision for asset retirement obligations are recognized based on current legal and constructive requirements, technology and price levels. Provision is recorded based on the estimates received from the operator, where available, or the information provided by the technical department of the Company based on the best estimates. However, the actual outflows can differ from the estimated cash outflows due to changes in laws, regulations, public expectations, technology, prices and conditions, and can take place many years in the future; the carrying amount of provision is reviewed and adjusted to take account of such changes.

e) *Recognition of deferred tax assets*

The recognition of deferred tax assets is based upon whether it is more likely than not that sufficient and suitable taxable profits will be available in the future against which the reversal of temporary differences can be deducted. To determine the future taxable profits, reference is made to the latest available profit forecasts. Where the temporary differences are related to losses, relevant tax law is considered to determine the availability of the losses to offset against the future taxable profits.

Significant items on which the Company has exercised accounting judgement include recognition of deferred tax assets in respect of tax losses in Pakistan.

f) *Measurement of share-based payments*

Share-based payments recorded pursuant to share-based compensation plans are subject to estimated fair values, forfeiture rates, volatility and the future attainment of performance criteria, if any.

<u>Critical judgements in applying the entity's accounting policies</u>

g) *Determination of cash-generating units for impairment testing*

For the purpose of impairment testing, oil and gas properties are aggregated into CGUs, based on separately identifiable and largely independent cash flows. The determination of the Company's CGUs, however, is subject to judgement.

h) *Asset retirement obligation*

Provision is recognized for the future restoration cost of oil and gas wells, production facilities and pipelines at the end of their economic lives. The timing of recognition requires the application of judgment to existing facts and circumstances, which can be subject to change.

i) *Fair valuation of embedded derivatives and stock options at grant date*

The fair value of financial instruments that are not traded in an active market (for example, over-the-counter derivatives) is determined by using valuation techniques. The Company uses its judgement to select a variety of methods and make assumptions that are mainly based on market conditions existing at the grant date and at each reporting date. The Company has used Black-Scholes option pricing model for fair valuation of stock options at grant date and embedded derivatives at reporting date.

Financial Risk Management

Financial risk factors

The Company's activities expose it to a variety of financial risks: market risk (including currency risk, fair value interest rate risk, cash flow interest rate risk and price risk), credit risk and liquidity risk. The Company's overall risk management program focuses on the unpredictability of financial markets and seeks to minimize potential adverse effects on the Company's financial performance. Risk management is carried out by the Board. The Board provides risk management guidance covering specific areas such as foreign exchange risk, interest rate risk, credit risk and investment of excess liquidity.

Market risk

(i) Currency risk

Currency risk is the risk that the fair value or future cash flows of a financial instrument will fluctuate because of changes in foreign exchange rates. Currency risk arises mainly from future commercial transactions, or receivables and payables that exist due to transactions in foreign currencies. The Company is exposed to currency risk arising from various currency exposures, primarily with respect to the Pakistan Rupee (PKR), Canadian Dollar (CAD) and Arab Emirates Dirham (AED). Currently, the Company's foreign exchange risk exposure is restricted to the amounts receivable from / payable in foreign currency. The Company's exposure to currency risk is as follows:

Description	December 31, 2014	December 31, 2013
	--------------$-----------	
PKR		
Bank balances	11,618	50,308
Accounts and other receivables	306,237	130,785
Accounts payable and accrued liabilities	(323,273)	(40,945)
Borrowings	(3,833,505)	-
Net exposure	**(3,838,923)**	**140,148**
CAD		
Bank balances	10,893	56,772
Accounts and other receivables	11,177	12,720
Accounts payable and accrued liabilities	(203,475)	(180,361)
Net exposure	**(181,405)**	**(110,869)**
AED		
Bank balances	**-**	**238**

The following significant exchange rates were applied during the year:

Description	2014	2013
PKR per USD		
Average rate	101.01	100.75
Reporting date rate	101.94	105.14
CAD per USD		
Average rate	1.10	1.02
Reporting date rate	1.16	1.07
AED per USD		
Average rate	3.67	3.67
Reporting date rate	3.67	3.67

If the functional currency, at the reporting date, had fluctuated by 5% against the PKR, CAD and AED with all other variables held constant, the impact on comprehensive income / (loss) for the year would have been $201,016 (2013: $1,475) respectively lower / higher, mainly as a result of exchange gains / losses on translation of foreign exchange denominated financial instruments. Currency risk sensitivity to foreign exchange movements has been calculated on a symmetric basis.

(ii) Other price risk

Other price risk represents the risk that the fair value or future cash flows of a financial instrument will fluctuate because of changes in market prices (other than those arising from interest rate risk or currency risk), whether those changes are caused by factors specific to the individual financial instrument or its issuer, or factors affecting all similar financial instruments traded in the market.

The Company does not have any financial instrument exposed to other price risk.

(iii) Interest rate risk

Interest rate risk represents the risk that the fair value or future cash flows of a financial instrument will fluctuate because of changes in market interest rates. At the date of the statement of financial position, the interest rate profile of the Company's interest bearing financial instruments is:

Description	**December 31, 2014**	**December 31, 2013**
	------------$----------	
Fixed rate instruments		
- Subordinated debentures	3,852,536	3,807,144
Floating rate instruments		
Bank borrowing	3,833,505	-
- Shareholder loan	8,416,707	5,577,127

Fair value sensitivity analysis for fixed rate instruments

If the interest rate, at the reporting date, had fluctuated by 1% with all other variables held constant, the impact on comprehensive income / (loss) for the year would have been $122,502 (December 31, 2013 $33,342) respectively lower / higher, mainly as a result of interest on floating rate financial instruments. Interest rate risk sensitivity to foreign exchange movements has been calculated on a symmetric basis.

(iv) Credit risk

Credit risk represents the risk that one party to a financial instrument will cause a financial loss for the other party, by failing to discharge an obligation. The maximum exposure to credit risk at the reporting date is as follows:

Description	**December 31, 2014**	**December 31, 2013**
	------------$---------	
Cash at bank	147,181	427,798
Restricted cash	35,024	1,247,261
Accounts and other receivables	2,188,743	1,562,894
Total	**2,370,948**	**3,237,953**

The credit risk on liquid funds is limited, because the counter parties are banks with reasonably high credit ratings. In case of trade receivables the Company believes that it is not exposed to major concentrations of credit risk, due to high credit worthiness of corresponding parties.

The credit quality of bank balances and restricted cash, that are neither past due nor impaired, can be assessed by reference to external credit ratings (if available) or to historical information about counterparty default rate:

Description	Rating agency	Credit rating	2014	2013
			----------$------------	
HSBC – Canada	Moody's[1]	A1	66,838	131,659
HSBC – Australia	Moody's	A1	86,821	185,107
HSBC – UAE	Moody's	A2	-	1,199,859
Meezan Bank Limited	JCR-VIS[3]	AA	854	822
Bank Alfalah Limited	PACRA[2]	AA	617	612
Askari Bank Limited	PACRA	AA	1,331	1,315
JS Bank Limited	PACRA	A+	15,216	145,832
Albaraka Bank Pakistan Limited	PACRA	A	10,528	9,853
Total			**182,205**	**1,675,059**

[1]Moody's Investors Service
[2]The Pakistan Credit Rating Agency Limited
[3]Japan Credit Rating Agency, Ltd (JCR) and Vital Information Services (Pvt.) Limited (VIS)

Due to the Company's long standing business relationships with these counterparties, and after giving due consideration to their strong financial standing, management does not expect non-performance by these counter parties on their obligations to the Company. Accordingly, the credit risk is minimal.

As of December 31, 2014, trade receivables of $ 1,811,542 (2013: $ 153,514) were past due but not impaired. The ageing analysis of these trade receivables is as follows:

Description	December 31, 2014	December 31, 2013
	----------$------------	
Up to 3 months	1,675,371	153,514
3 to 6 months	136,171	-
6 to 9 months	-	-
Total	**1,811,542**	**153,514**

(v) Liquidity risk

Liquidity risk is the risk that an entity will encounter difficulty in meeting obligations associated with financial liabilities. The Company follows an effective cash management and planning to ensure availability of funds, and to take appropriate measures for new requirements.

The following are the contractual maturities of financial liabilities as at December 31, 2014:

Description	Carrying amount	Less than one year	One to five years
	----------------$----------------		
Accounts payable and accrued liabilities	6,681,751	6,681,751	-
Borrowings	17,970,761	13,137,256	4,833,505
Total	**24,652,512**	**19,819,007**	**4,833,505**

The following are the contractual maturities of financial liabilities as at December 31, 2013:

Description	Carrying amount	Less than one year	One to five years
	----------$-----------		
Accounts payable and accrued liabilities	574,513	574,513	-
Borrowings	11,759,790	7,952,646	3,807,144
Total	**12,334,303**	**8,527,159**	**3,807,144**

There is a material uncertainty about the Company's ability to continue as going concern.

Fair value of financial assets and liabilities

The fair valuation of financial assets and liabilities is determined using different levels defined as follows:

- Quoted prices (unadjusted) in active markets for identical assets or liabilities (Level 1).
- Inputs other than quoted prices included within level 1 that are observable for the asset or liability, either directly (that is, as prices) or indirectly (that is, derived from prices) (Level 2).
- Inputs for the asset or liability that are not based on observable market data (that is unobservable inputs) (Level 3).

The carrying values of all other financial assets and liabilities approximate their fair values. Fair value is determined on the basis of objective evidence at each reporting date. Fair value of embedded derivative on Shareholder loan has calculated using Level 2 valuation method.

Financial instruments by category

Financial assets	December 31, 2014	December 31, 2013
	Loans and receivables	
	-----------$-----------	
Cash and cash equivalents	147,476	429,484
Restricted cash	35,024	1,247,261
Accounts and other receivables	2,188,743	1,562,894
Total	**2,371,243**	**3,239,639**
Financial liabilities	**Other financial liabilities**	
Accounts payable and accrued liabilities	6,681,751	574,513
Borrowings	17,970,761	11,759,790
Total	**24,652,512**	**12,334,303**

Capital risk management

The Board's policy is to maintain an efficient capital base so as to maintain investor, creditor and market confidence, and to sustain the future development of the Company's business. The Board monitors the return on capital employed, which the Company defines as operating income divided by total capital employed. The Board also monitors the level of dividends to ordinary shareholders.

The Company's objectives when managing capital are:

i) to safeguard the entity's ability to continue as a going concern, so that it can continue to provide returns for shareholders and benefits for other stakeholders; and

ii) to provide an adequate return to shareholders.

The Company manages the capital structure in the context of economic conditions and the risk characteristics of the underlying assets. In order to maintain or adjust the capital structure, the Company may issue new shares, or sell assets to reduce debt obligations.

For working capital and capital expenditure requirements, the Company primarily relies on internal cash generation and financial support of the parent company.

Risk Factors

The business of exploring for, developing and producing oil and gas reserves is inherently risky. The Company will face numerous and varied risks which may prevent it from achieving its goals. The Company's actual exploration and operating results may be very different from those expected as at the date of this MD&A. Also see "Risk Factors" in the Company's Annual Information Form for the year ended December 31, 2014 for a further description of the risks and uncertainties associated with the Company's business and recovery of its oil and gas reserves and resources.

Obtaining financing

The Company is in the growth phase of its oil and gas operations with limited revenues from three properties and majority of its properties are in exploration and development stage. There can be no assurance of its ability to develop and operate its projects profitably. The Company has been historically depended upon the financial support from its shareholders to provide the finance needed to fund its operations, but the Company cannot assure that the shareholders will continue to do so. The Company's ability to continue in business depends upon its continued ability to obtain significant financing from internal as well as external sources and the success of its exploration efforts and any production efforts resulting there from. Any reduction in its ability to raise finance in the future would force the Company to reallocate funds from other planned uses and could have a significant negative effect on its business plans and operations, including its ability to continue its current development and exploration activities.

Commercial Risk

In order to assign recoverable resources of oil and gas, the Company must establish a development plan consisting of one or more projects. In-place quantities for which a feasible project cannot be defined using established technology or technology under development are classified as unrecoverable. In this context, "technology under development" refers to technology that has been developed and verified by testing as feasible for future commercial applications to the subject reservoir. In the early stage of exploration or development, as is the case for the Company, project definition will not be of the detail expected in the later stages of maturity. In most cases, recovery efficiency will be largely based on analogous projects.

Estimates of recoverable quantities are stated in terms of the sales products derived from a development program, assuming commercial development. It must be recognized that reserves, contingent resources and prospective resources involve different risks associated with achieving commerciality. The likelihood that a project will achieve commerciality is referred to as the "chance of commerciality." The chance of commerciality varies in different categories of recoverable resources as follows:

> ***Reserves*:** To be classified as reserves, estimated recoverable quantities must be associated with a project(s) that has demonstrated commercial viability. Under the fiscal conditions applied in the estimation of reserves, the chance of commerciality is effectively 100%.
>
> ***Contingent Resources*:** Not all technically feasible development plans will be commercial. The commercial viability of a development project is dependent on the forecast of fiscal conditions over the life of the project. For contingent resources, the risk component relating to the likelihood

that an accumulation will be commercially developed is referred to as the "chance of development." For contingent resources, the chance of commerciality is equal to the chance of development.

Prospective Resources**:** Not all exploration projects will result in discoveries. The chance that an exploration project will result in the discovery of petroleum is referred to as the "chance of discovery." Thus, for an undiscovered accumulation, the chance of commerciality is the product of two risk components -- the chance of discovery and the chance of development.

Exploration Risk

Oil and gas exploration involves a high degree of risk. These risks are more acute in the early stages of exploration. The Company's exploration expenditures may not result in new discoveries of oil or gas in commercially viable quantities. It is difficult to project the costs of implementing an exploratory drilling program due to the inherent uncertainties of drilling in unknown formations, the costs associated with encountering various drilling conditions, such as over pressured zones and tools lost in the hole, and changes in drilling plans and locations as a result of prior exploratory wells or additional seismic data and interpretations thereof. If exploration costs exceed estimates, or if exploration efforts do not produce results that meet expectations, exploration efforts may not be commercially successful, which could adversely impact the ability to generate revenues from operations.

Operational Risk

If the Company's operations are disrupted and/or the economic integrity of its projects is threatened for unexpected reasons, business may experience a setback. These unexpected events may be due to technical difficulties, operational difficulties including floods which impact the production, transport or sale of products, geographic and weather conditions, business reasons or otherwise. Because the Company is in its early stages of development, it is particularly vulnerable to these events. Prolonged problems may threaten the commercial viability of operations.

Development Risk

To the extent that the Company succeeds in discovering oil and/or gas, reserves may not be capable of production levels projected or in sufficient quantities to be commercially viable. On a long-term basis, the Company's viability depends on the ability to find or acquire, develop and commercially produce additional oil and gas reserves. Without the addition of reserves through exploration, acquisition or development activities, reserves and production will decline over time as reserves are produced. Future reserves will depend not only on the ability to develop then-existing properties, but also on the ability to identify and acquire additional suitable producing properties or prospects, to find markets for the oil and natural gas developed and to effectively distribute production into markets. Future oil and gas exploration may involve unprofitable efforts, not only from dry wells, but from wells that are productive but do not produce sufficient net revenues to return a profit after drilling, operating and other costs. Completion of a well does not assure a profit on the investment or recovery of drilling, completion and operating costs. In addition, drilling hazards or environmental damage could greatly increase the cost of operations, and various field operating conditions may adversely affect the production from successful wells. These conditions include delays in obtaining governmental approvals or consents, shut-downs of connected wells resulting from extreme weather conditions, problems in storage and distribution and adverse geological and mechanical conditions. While the Company will endeavor to effectively manage these conditions, it may not be able to do so optimally, and will not be able to eliminate them completely in any case. Therefore, these conditions could diminish revenue and cash flow levels and result in the impairment of oil and gas interests.

Drilling Risks

There are risks associated with the drilling of oil and gas wells, including encountering unexpected formations or pressures, premature declines of reservoirs, blow-outs, craterings, sour gas releases, fires, spills or natural disasters. The occurrence of any of these and other events could significantly reduce revenues or cause substantial losses, impairing future operating results. The Company may become subject to liability for pollution, blow-outs or other hazards. The Company obtains insurance with respect to these hazards, but such insurance has limitations on liability that may not be sufficient to cover the full extent of such liabilities. The payment of such liabilities could reduce the funds available to the Company or could, in an extreme case, result in a total loss of properties and assets. Moreover, the Company may not be able to maintain adequate insurance in the future at rates that are considered reasonable. Oil and gas production operations are also subject to all the risks typically associated with such operations, including premature decline of reservoirs and the invasion of water into producing formations.

Environmental Risks

All phases of the oil and gas business present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of international conventions and federal, 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 that may result in stricter standards and enforcement, larger fines and liability and potentially increased capital expenditures and operating costs. The discharge of oil, natural gas or other pollutants into the air, soil or water may give rise to liabilities to foreign governments and third parties and may require the Company to incur costs to remedy such discharge. The application of environmental laws to the Company's business may cause it to curtail production or increase the costs of production, development or exploration activities.

Operations

Operations are subject to all of the risks frequently encountered in the development of any business, including control of expenses and other difficulties, complications and delays, as well as those risks that are specific to the oil and gas industry.

Reserve Estimates

The Company makes estimates of oil and gas reserves, upon which it bases financial projections. The Company makes these reserve estimates using various assumptions, including assumptions as to oil and gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. Some of these assumptions are inherently subjective, and the accuracy of reserve estimates relies in part on the ability of the management team, engineers and other advisers to make accurate assumptions. Economic factors beyond the Company's control, such as interest rates and exchange rates, will also impact the value of reserves. The process of estimating oil and gas reserves is complex, and requires the Company to make significant decisions and assumptions in the evaluation of available geological, geophysical, engineering and economic data for each property. As a result, reserve estimates will be inherently imprecise. Actual future production, oil and natural gas prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable oil and gas reserves may vary substantially from those estimated. If actual production results vary substantially from reserve estimates, this could materially reduce revenues and result in the impairment of oil and gas interests.

Facilities

Oil and gas exploration and development activities are dependent on the availability of drilling and related equipment, transportation, power and technical support in the particular areas where these activities will be conducted, and access to these facilities may be limited. To the extent that operations are conducted in remote areas, needed facilities may not be proximate to operations, which will increase expenses. Demand for such limited equipment and other facilities or access restrictions may affect the availability of such equipment to the Company and may delay exploration and development activities. The quality and reliability of necessary facilities may also be unpredictable and the Company may be required to make efforts to standardize facilities, which may entail unanticipated costs and delays. Shortages and/or the unavailability of necessary equipment or other facilities will impair activities, either by delaying activities, increasing costs or otherwise.

Operating Expenses

Exploration, development, production, marketing (including distribution costs) and regulatory compliance costs (including taxes) substantially impact the net revenues derived from oil and gas produced. These costs are subject to fluctuations and variation in different locales in which the Company will operate, and the Company may not be able to predict or control these costs. If these costs exceed expectations, this may adversely affect results of operations. In addition, the Company may not be able to earn net revenue at predicted levels, which may impact the ability to satisfy any obligations.

Fluctuations in Operating Results can cause Share Price Decline

The Company's operating results will likely vary in the future primarily from fluctuations in revenues and operating expenses, including the ability to produce the oil and gas reserves that are developed, expenses that are incurred, the prices of oil and gas in the commodities markets and other factors. If the results of operations do not meet the expectations of current or potential investors, the price of the Company's shares may decline.

Decommissioning Costs

The Company may become responsible for costs associated with abandoning and reclaiming wells, facilities and pipelines which are used for production of oil and gas reserves. Abandonment and reclamation of these facilities and the costs associated therewith is often referred to as "decommissioning." If decommissioning is required before economic depletion of the properties or if estimates of the costs of decommissioning exceed the value of the reserves remaining at any particular time to cover such decommissioning costs, the Company may have to draw on funds from other sources to satisfy such costs. The use of other funds to satisfy such decommissioning costs could impair the ability to focus capital investment in other areas of the business.

Foreign Operations

The oil and gas industry in Pakistan is not as efficient or developed as the oil and gas industry in Canada. As a result, exploration and development activities may take longer to complete and may be more expensive than similar operations in Canada. The availability of technical expertise, specific equipment and supplies may be more limited and such factors may subject international operations to economic and operating risks that may not be experienced in Canadian operations.

Local Legal, Political and Economic Factors

Currently the Company is operating its oil and gas activities in Pakistan. Exploration and production operations in foreign countries are subject to legal, political and economic uncertainties, including interference with private contract rights (such as privatization), extreme fluctuations in currency exchange rates, high rates of inflation, exchange controls, changes in tax rates and other laws or policies affecting environmental issues (including land use and water use), workplace safety, foreign investment, foreign trade, investment or taxation, as well as restrictions imposed on the oil and gas industry, such as restrictions on production, price controls and export controls. Political and economic instability could result in new governments or the adoption of new policies, laws or regulations that might assume a substantially more hostile attitude toward foreign investment, including imposing additional taxes. In an extreme case, such a change could result in termination of contract rights and expropriation of foreign-owned assets. Any changes in oil and gas or investment regulations and policies or a shift in political attitudes in Pakistan will be beyond the Company's control and may significantly hamper the ability to expand operations or operate the business at a profit.

Enforcement of Civil Liabilities

Certain of the directors of the Company reside outside of Canada and, similarly, a majority of the assets of the Company are located outside of Canada. It may not be possible for investors to effect service of process within Canada upon directors not residing in Canada. It may also not be possible to enforce against the Company and certain of its directors judgments obtained in Canadian courts predicated upon the civil liability provisions of applicable securities laws in Canada.

Penalties

The Company's exploration, development, production and marketing operations are regulated under foreign federal, state and local laws and regulations. Under these laws and regulations, the Company could be held liable for personal injuries, property damage, site clean-up and restoration obligations or costs and other damages and liabilities. The Company may also be required to take corrective actions, such as installing additional safety or environmental equipment, which could require significant capital expenditures. Failure to comply with these laws and regulations may also result in the suspension or termination of operations and subject the Company to administrative, civil and criminal penalties, including the assessment of natural resource damages. The Company could be required to indemnify employees in connection with any expenses or liabilities that they may incur individually in connection with regulatory action against them. As a result of these laws and regulations, future business prospects could deteriorate and profitability could be impaired by costs of compliance, remedy or indemnification of employees, thus reducing profitability.

Competition for Exploration and Development Rights

The oil and gas industry is highly competitive. This competition is increasingly intense as prices of oil and gas on the commodities markets have raised in recent years. Additionally, other companies engaged in the same line of business may compete with the Company from time to time in obtaining capital from investors. Competitors include larger, foreign owned companies, which, in particular, may have access to greater resources than the Company, may be more successful in the recruitment and retention of qualified employees and may conduct their own refining and petroleum marketing operations, which may give them a competitive advantage. In addition, actual or potential competitors may be strengthened through the acquisition of additional assets and interests.

Technology

The Company relies on technology, including geographic and seismic analysis techniques and economic models, to develop reserve estimates and to guide exploration and development and production activities. The Company will be required to continually enhance and update its technology to maintain its efficacy and to avoid obsolescence. The costs of doing so may be substantial, and may be higher than the costs that are anticipated for technology maintenance and development. If the Company is unable to maintain the efficacy of the technology, the ability to manage the business and to compete may be impaired. Further, even if technical effectiveness is maintained, the technology may not be the most efficient means of reaching objectives, in which case higher operating costs may be incurred than if the technology was more efficient.

Foreign Currency Exchange Rate Fluctuation

The Company may sell oil and gas production under agreements that may be denominated in United States dollars or other foreign currencies. Many of the operational and other expenses incurred will be paid in the local currency of the country containing the operations. As a result, the Company will be exposed to currency exchange rate fluctuation and translation risk when local currency financial statements are translated to Canadian dollars, which may have a significant effect on profitability and/or comparability of revenues and expenses between periods.

Exchange Controls

Foreign operations may require funding if their cash requirements exceed operating cash flow. To the extent that funding is required, there may be exchange controls limiting such funding or adverse tax consequences associated with such funding. In addition, taxes and exchange controls may affect the dividends received from foreign subsidiaries. Exchange controls may prevent transferring funds abroad.

Insurance

Involvement in the exploration for and development of oil and gas properties may result in the Company becoming subject to liability for pollution, blow-outs, property damage, personal injury or other hazards. Any insurance that the Company may obtain may have limitations on liability that may not be sufficient to cover the full extent of such liabilities. In addition, such risks may not, in all circumstances, be insurable or, in certain circumstances, the Company may choose not to obtain insurance to protect against specific risks due to the high premiums associated with such insurance or for other reasons. The payment of such uninsured liabilities would reduce funds available. If the Company suffers a significant event or occurrence that is not fully insured, or if the insurer of such event is not solvent, the Company could be required to divert funds from capital investment or other uses towards covering the liability for such events.

Attracting and Retaining Talented Personnel

The Company's success depends in large measure on the abilities, expertise, judgment, discretion, integrity and good faith of management and other personnel in conducting the business of the Company. The Company has a small management team and the loss of any of these individuals or the inability to attract suitably qualified staff could materially adversely impact the business. The Company may also experience difficulties in certain jurisdictions in efforts to obtain suitably qualified staff and in retaining staff who are willing to work in that jurisdiction. The Company's success will depend on the ability of management and employees to interpret market and geological data successfully and to interpret and respond to economic, market and other business conditions in order to locate and adopt appropriate investment opportunities, monitor such investments and ultimately, if required, successfully divest such investments. Further, key personnel may not continue their association or employment with the Company, which may not be able to find replacement personnel with comparable skills. The Company has sought to and will continue to ensure that management and any key employees are appropriately compensated; however, their services cannot be guaranteed. If the Company is unable to attract and retain key personnel, business may be adversely affected.

Growth Management

The Company's strategy envisions expanding the business. If the Company fails to effectively manage growth, financial results could be adversely affected. Growth may place a strain on management systems and resources. The Company will need to continue to refine and expand business development capabilities, systems and processes and access to financing sources. As the Company grows, it will need to continue to hire, train, supervise and manage new employees. The Company may not be able to:

(i) Expand systems effectively or efficiently or in a timely manner;

(ii) Allocate human resources optimally;

(iii) Identify and hire qualified employees or retain valued employees; or

(iv) Incorporate effectively the components of any business that may be acquired in the effort to achieve growth.

If the Company is unable to manage growth and operations, the financial results could be adversely affected by inefficiency, which could diminish profitability.

Outstanding Share Capital

The Company has 69,076,328 common shares, 2,368,294 stock options and 850,000 share purchase warrants outstanding as at March 20, 2014.

Disclosure Controls and Procedures, and Internal Controls over Financial Reporting

As at December 31, 2014, an evaluation of the effectiveness of the Company's disclosure controls and procedures as defined under the rules adopted by the Canadian securities regulatory authorities was carried out under the supervision and with the participation of management, including the Interim Chief Executive Officer ("CEO") and the Chief Financial Officer ("CFO"). Based on this evaluation, the CEO and the CFO concluded that, as at December 31, 2014, the design and operation of Company's disclosure controls and procedures were effective to provide reasonable assurance that information required to be disclosed by the Corporation in reports filed with, or submitted to, securities regulatory authorities were reported within the time periods specified under Canadian securities laws.

Internal control over financial reporting is a process designed by or under the supervision of management and effected by the Board, management and other personnel to provide reasonable assurance regarding the reliability of financial reporting and preparation of consolidated financial statements for external purposes in accordance with IFRS. Management is responsible for establishing and maintaining adequate internal control over financial reporting. Internal control over financial reporting, no matter how well designed, has inherent limitations and can provide only reasonable assurance with respect to the preparation and fair presentation of published financial statements. Under the supervision and with the participation of the CEO and CFO, management conducted an evaluation of the effectiveness of its internal control over financial reporting.

Based on this evaluation, the CEO and CFO concluded that internal control over financial reporting was effective as at December 31, 2014, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external reporting purposes. On May 14, 2013, the Committee of Sponsoring Organizations of the Tread way Commission ("COSO") published an updated *Internal Control – Integrated Framework* and related illustrative documents, which will supersede the 1992 COSO Framework as of December 15, 2014. As of December 31, 2014, the Company was utilizing the original framework published in 1992, but is transitioning to the 2013 COSO Framework as it relates to its internal control over financial reporting. In 2014 there was no change in Company's internal control over financial reporting that materially affected or is reasonably likely to materially affect the Company's internal control over financial reporting.

Approval

The Company's Audit Committee has approved the disclosure contained within this MD&A. Additional information relating to the Company, including the Company's Annual Information Form, is available on SEDAR at www.sedar.com.