JURA ENERGY CORPORATION

MANAGEMENT'S DISCUSSION AND ANALYSIS
FOR THE YEAR ENDED
DECEMBER 31, 2018 and 2017

April 29, 2019

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"), PetExPro Ltd., (*formerly Frontier Acquisition Company Limited*) ("PEPL"), Frontier Oil and Gas Holdings Limited ("FOGHL") and Frontier Holdings Limited ("FHL") for the years ended December 31, 2018 and 2017 and the Company's financial position as at December 31, 2018. This MD&A is approved by the Board of Directors (the "Board") on April 29, 2019, and should be read in conjunction with the annual audited consolidated financial statements of the Company for the years ended December 31, 2018 and 2017.

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

Non-IFRS Financial Measures

This MD&A refers to certain financial measures that are not determined in accordance with IFRS. The terms net revenue per Barrel of Oil Equivalent ("Boe"), production cost per Boe, depletion per Boe and operating netback per Boe are not measures recognized under IFRS and do not have standardized meanings prescribed by IFRS. Management considers these to be important supplemental measures of the Company's performance and believes these measures are frequently used by securities analysts, investors and other interested parties in the evaluation of companies operating in similar industries.

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 annual financial statements of the Company, divided by production for the year.

Readers are encouraged to evaluate each adjustment and the reasons, the Company considers appropriate for the supplemental analysis. Readers are cautioned, however, that these measures should not be construed as an alternative to net income / (loss) determined in accordance with IFRS as an indication of the Company's performance.

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, Aminah and Ayesha North leases in the Badin IV South exploration license, Umair-1 gas discovery in Guddu exploration license, Zainab-1 gas and condensate discovery in Badin IV North exploration license, development well Sara-4 and Suri shut-in well; expectation regarding grant of development and production lease for Zainab-1 gas and condensate discovery in Badin IV North exploration license; expected pricing under Pakistan Petroleum (Exploration and Production) Policy, 2012 and other pricing policies; timing for and drilling results of exploration wells in the Badin IV South and Guddu exploration licenses and expectations regarding the grant of or extension applied in terms of expired exploration licenses and leases by the Government of Pakistan ("GoP"). 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 therefrom. 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 the date of this MD&A, 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.

Highlights

The key highlights for the year ended December 31, 2018, and up to the date of this MD&A are as follows:

- The Company reported a net profit for the year ended December 31, 2018 of $0.01 million compared to a net loss of $1.32 million in 2017. The net profit for the current year is mainly due to an increase in revenue, un-realized exchange gain on retranslation of foreign currency denominated borrowings and payables, a decrease in general and administrative expenses following management team restructuring in Q3 2017, overall reduction in Pak Rupee ("PKR") denominated cost of operations in Pakistan due to significant devaluation of PKR against US Dollar offset by impairment of oil and gas properties and recognition of deferred tax liability due to reduction in value of PKR denominated tax losses and allowances;

- Gross profit for the year ended December 31, 2018 was $6.89 million compared to a gross profit of $3.81 million in 2017. The significant increase in gross profit is due to an increase in revenue and reduction in field operating costs due to devaluation of PKR against US Dollar and overall cost optimisation of Zarghun South field;

- Net revenue during 2018 increased by 29% compared to the year ended December 31, 2017. The significant increase in revenue is due to increase in production and average realized price on account of improvement in international crude oil prices;

- Production during the year ended December 31, 2018 increased by 2% compared to the year ended December 31, 2017 due to resumption of production from Khamiso and Maru East wells in Guddu block;

- The drilling of exploration well, Umair-1, in Guddu exploration license commenced in January 2018;

- In February 2018, Umair-1 was completed as gas producer well;

- In April 2018, SEPL, JEC and JS Energy Limited entered into a short-term loan agreement of $2 million;
- In May 2018, JEC completed a private placement of 3,500 units of new $1,000 subordinated debentures;
- The acquisition of 545 Sq. Km 3D seismic data in Guddu Block is complete and the processing is in progress; and
- In March 2019, the operator commenced acquisition of 100 L. Km of 2D seismic data in Zarghun South.

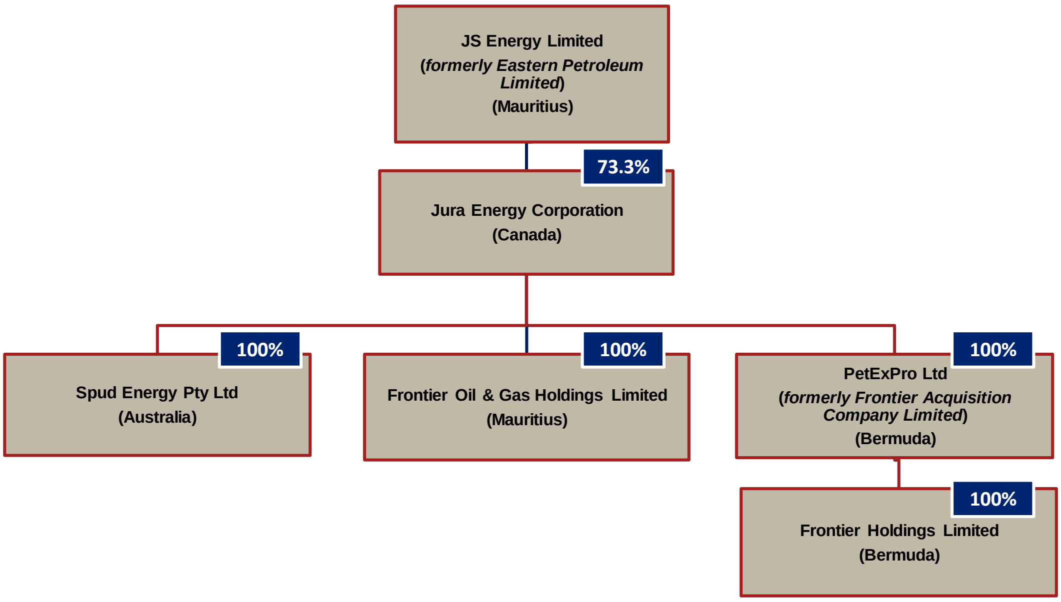
Overview of the Company and Operations

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 the following exploration licenses/leases through its wholly-owned subsidiaries Spud Energy Pty Limited ("SEPL") and Frontier Holdings Limited ("FHL"):

Exploration licenses/leases	Working Interest	Operator
Producing		
Badar lease*	7.89%	Petroleum Exploration (Private) Limited
Zarghun South lease	40.00%	Mari Petroleum Company Limited
Reti lease	10.66%	Oil and Gas Development Company Limited
Maru lease	10.66%	Oil and Gas Development Company Limited
Maru South lease	10.66%	Oil and Gas Development Company Limited
Development		
Sara lease	60.00%	Spud Energy Pty Limited
Suri lease	60.00%	Spud Energy Pty Limited
Kandra lease*	37.50%	Petroleum Exploration (Private) Limited
Ayesha lease	27.50%	Petroleum Exploration (Private) Limited
Aminah lease	27.50%	Petroleum Exploration (Private) Limited
Ayesha North lease	27.50%	Petroleum Exploration (Private) Limited
Exploration		
Kandra exploration rights	35.00%	Petroleum Exploration (Private) Limited
Guddu exploration license	13.50%	Oil and Gas Development Company Limited
Zamzama North exploration license	24.00%	Heritage Oil and Gas Limited
Sanjawi exploration license	27.00%	Heritage Oil and Gas Limited
Badin IV South exploration license	27.50%	Petroleum Exploration (Private) Limited
Badin IV North exploration license	27.50%	Petroleum Exploration (Private) Limited

*Pursuant to the terms of Settlement Agreement entered into between SEPL, FHL and PEL, effective August 12, 2016, SEPL and FHL has agreed to assign SEPL's 7.89% working interest in Badar and FHL's 37.5% working interest in Kandra lease to PEL. The applications for the assignment of 7.89% working interest in Badar and 37.5% working interest in Kandra lease have been submitted to Government of Pakistan, the approval of which is expected in due course.

The group structure of the Company is as indicated below:



Background of Oil and Gas Properties

SEPL has operated working interest in two leases and non-operated working interests in four leases and three exploration licenses. The working interest ranges from 10.66% to 60%.

FHL has non-operated working interests in two exploration licenses, three development and production leases and exploration rights within the Kandra lease. The working interest ranges from 27.5% to 35%.

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 March 2018, the Economic Coordination Committee of the Federal Cabinet ("ECC") granted exemption from Rule 43 of Pakistan Petroleum (Exploration and Production) Rules 1986 ("Rules 1986") for the Sara and Suri leases for a period of six months, an extension of the Sara and Suri leases up to February 2020 and approval for the sale of gas from the Sara and Suri leases to a third party at a negotiated price. In April 2018, SEPL commenced the bidding process for the sale of gas to a third party.

The sale of gas from the Sara and Suri leases to Konnect Gas (Pvt) Limited ("KGPL"), an affiliate of SEPL, being the sole bidder, was finalized and a summary of commercial terms was submitted to the OGDCL for approval. In August 2018, OGDCL approved the commercial terms for sale of gas to KGPL.

The exemption from Rule 43 of Rules 1986 for Sara and Suri leases expired on September 8, 2018. On September 7, 2018, SEPL submitted an application to DGPC for an exemption under Rule 43 of Rules 1986 for a period of six months from the date of approval. Pursuant to Rule 43 of Rules 1986, a lease may be revoked if commercial production has not commenced within five years from the date of grant of the lease or if the production has terminated for more than 90 days, unless this is due to force majeure. SEPL believes that the approval of exemption under Rule 43 of Rules 1986 will be granted in due course.

The sale of approximately 1-1.3 million cubic feet per day ("MMcf/d") of gas from the Sara and Suri leases to KGPL will commence after the exemption is granted under Rule 43 of Rules 1986 by DGPC.

Non-operated Concessions

Badar Lease

SEPL holds a 7.89% working interest in the Badar lease. Pursuant to the terms of the Settlement Agreement entered into between SEPL, FHL and PEL, effective August 12, 2016, SEPL has agreed to assign its 7.89% working interest in Badar lease to PEL.

Zarghun South Lease

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

Commercial production from Zarghun South commenced in August 2014. During 2018, average production from Zarghun South was approximately 14.91 MMcf/d.

A supplemental Zarghun South GSA to incorporate provisions related to supply of tight gas has been submitted to Sui Southern Gas Company Limited ("SSGCL") for approval and execution, which is expected in due course.

In order to optimise the field production, the Zarghun South JV Partners have approved the drilling of fourth development well "ZS-4" and acquisition of ~100 L. Km firm and ~42 L. Km contingent 2D seismic data. The well location will be finalized after the interpretation of 2D seismic data.

Kandra Lease

FHL holds a 37.5% working interest in the Kandra lease**.** Pursuant to the terms of the Settlement Agreement entered into between SEPL, FHL and PEL, effective August 12, 2016, FHL has agreed to assign its 37.5% working interest in Kandra lease to PEL.

Ayesha, Aminah and Ayesha North Leases ("Badin IV South leases")

FHL holds a 27.5% working interest in the Badin IV South leases**.**

Gas production from Badin IV South leases has been allocated to SSGCL. The JV Partners are working on a fast-track development of the field.

The development plan envisages construction of a 30 MMcf/d Central Processing Facility ("CPF") at the Ayesha well location. Aminah and Ayesha North wells will be tied into the CPF through gathering flow lines. Processed gas from the CPF shall be transported through an approximately 29 km gas sale pipeline for tie-in into the SSGCL transmission system.

The development work is comprised of civil work, laying of gathering flow lines, construction of condensate storage tanks, fire water system, portable cabins, and processing plant. The processing plant arrived at the field site in February 2019 and the installation and commissioning is in progress. The installation and commissioning of the processing plant and all other ancillary development work is expected to be completed by the end of April 2019.

SSGCL has started the laying and construction of sale gas pipeline. The pipeline is expected to be completed by the end of April 2019. A gas sale and purchase agreement has been finalized with SSGCL, however, such agreement does not cover a waiver/discount for higher carbon dioxide contents, which is anticipated to be finalized after approval by the Oil and Gas Regulatory Authority ("OGRA"). The operator has submitted an application for OGRA's approval. SSGCL is anticipated to provide a waiver for a period of four to six months from the date of commencement of commercial production.

First gas from Badin IV South leases is expected to commence in May 2019.

The commercial production from Badin IV South leases is expected to entitled to a gas price of $5.19/MMBtu, based on the carriage and freight crude oil price of $65 per barrel, under the Pakistan's 2013 Marginal Fields Gas Pricing Criteria.

The Ayesha, Aminah and Ayesha North leases will expire in 2020, 2024 and 2025 respectively.

Reti, Maru and Maru South Leases and Maru East and Khamiso Gas Fields ("Reti-Maru leases")

SEPL holds a 10.66% working interest in the Reti-Maru leases.

Commercial production from the Reti-Maru leases commenced in December 2013. During 2017, average production from the leases was approximately 11.5 MMcf/d.

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, Umair-1, commenced in January 2018. Umair-1 was drilled to the total depth of 790 meters, to target Pirkoh and Habib Rahi limestone formations.

During a short duration pre-stimulation test on a 36/64-inch choke, the well flowed commingled gas from Pirkoh and Habib Rahi limestone formations at an average rate of ~2.47 MMcf/d, having a heating value of approximately 755 Btu/Scf, and a wellhead flowing pressure of approximately 330 psi. The well has been completed as a gas producer in the Pirkoh and Habib Rahi limestone formations.

Anticipated future production from the Umair-1 is expected to be entitled to a gas price of $4.45 per MMBtu, based on the carriage and freight crude oil price of $65 per barrel, under the Pakistan Petroleum (Exploration & Production) Policy, 2012.

In order to fully explore the hydrocarbon potential of the license, the Guddu JV Partners approved the acquisition and processing of 545 Sq. Km of 3D seismic data. 3D seismic acquisition has been completed. The operator has commenced data processing and the initial results are expected during the third quarter of 2019.

The GoP has approved SEPL's application for replacement of Guddu block's bank guarantee with the hypothecation of its reserves under the Zarghun South lease.

The Guddu exploration license will expire on May 24, 2020.

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. In February 2016, the DGPC issued a notice to the operator for the fulfillment of outstanding work obligations stipulated in the Zamzama North Petroleum Concession Agreement within a period of 60 days. The JV Partners are pursuing the matter with the DGPC.

The operator of the Sanjawi exploration license has declared force majeure in October 2011 due to security concerns. In February 2016, the DGPC, on behalf of the GoP, served a notice for termination of the Sanjawi exploration license. The JV Partners are pursuing the matter with the DGPC.

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 a 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.

The Phase II of the Badin IV South exploration license expired on July 5, 2018. On July 2, 2018, the operator on behalf of the JV Partners have submitted an application to DGPC for the grant of two years extension in license term. The approval is expected in due course.

Badin IV North Exploration License

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

The drilling of Zainab-1 commenced in June 5, 2017, and reached the targeted depth on June 28, 2017. The well was logged and completed in the Lower Goru "B" Sands of Cretaceous age. Post-completion surface well testing was conducted after perforating selective intervals of approximately 16.5 meters. A summary of the well testing results carried out at various choke sizes is as follows:

Choke size	Test duration	Average gas flow rates	Condensate rate	Water rate	Wellhead flowing pressure
	Hours	MMcf/d	Bbl/d	Bbl/d	Psi
32 / 64"	12	10.20	451	72	2,133
40 / 64"	12	14.30	500	130	2,026
48 / 64"	12	19.04	500	130	1,861
56 / 64"	24	23.04	772	54	1,724

The Zainab-1 well is located only 1.5 kilometers from existing gas pipeline infrastructure. Anticipated future production from exploration well, Zainab-1, is expected to entitled to a gas price of $5.19/MMBtu, based on the carriage and freight crude oil price of $65 per barrel, under the Pakistan's 2013 Marginal Fields Gas Pricing Criteria.

The operator has submitted declaration of commerciality of Zainab-1 and TORs for 3rd Party certification, to qualify for pricing incentive provided under Marginal Gas Pricing Criteria Guidelines 2013, to DGPC for approval. The approval is expected in due course.

On April 6, 2018, the operator on behalf of the JV Partners has submitted the field development plan alongwith the application for the grant of development and production lease for Zainab-1 gas and condensate discovery for a period of 10 years. The approval is expected in due course.

The Phase I of the initial term of the Badin IV North exploration license expired on December 6, 2017. On August 30, 2018, the DGPC, on behalf of GoP, granted approval for entering into Phase II of the initial term of the Badin IV North exploration license.

Performance Overview and Financial Analysis

Operational and Financial Results

Description	December 31,		
	2018	2017	2016
	----------$----------		
Net revenue	11,902,697	9,255,214	5,461,477
Gross profit	6,887,011	3,809,328	121,360
Net profit / (loss) for the year	9,473	(1,324,936)	(1,520,478)
Loss per share			
- Basic	0.00	(0.02)	(0.02)
- Diluted	0.00	(0.02)	(0.02)
Capital expenditure	4,680,201	1,412,950	2,729,444
Assets	53,888,746	57,366,408	53,179,583
Long term liabilities	25,288,012	24,015,241	25,025,048
Common shares outstanding at year-end			
Basic	69,076,328	69,076,328	69,076,328
Diluted	69,630,880	69,630,880	69,630,880
Cash dividend per share	-	-	-

JEC's revenue in 2018 represents gas sales from Reti-Maru and Zarghun South leases. The significant increase in revenue is due to slight increase in production during 2018 and an increase in average realized gas price due to improvement in international crude oil prices. Jura share of average daily production during 2018 was 7.19 MMcf/d compared to 7.03 MMcf/d in 2017.

JEC reported a net profit of $9,473 during 2018 compared to net loss of $1,324,936 in 2017. The net profit for the current year is mainly due to an increase in revenue, un-realized exchange gain on retranslation of foreign currency denominated borrowings and payables, a decrease in general and administrative expenses following management team restructuring in Q3 2017, overall reduction in PKR denominated cost of operations in Pakistan due to significant devaluation of PKR against US Dollar offset by impairment of oil and gas properties and recognition of deferred tax liability due to reduction in value of PKR denominated tax losses and allowances.

The capital expenditure incurred during 2018 mainly represents expenditure associated with the development of three gas and condensate discoveries in Badin IV South block, 3D seismic data acquisition and exploration drilling in Guddu block.

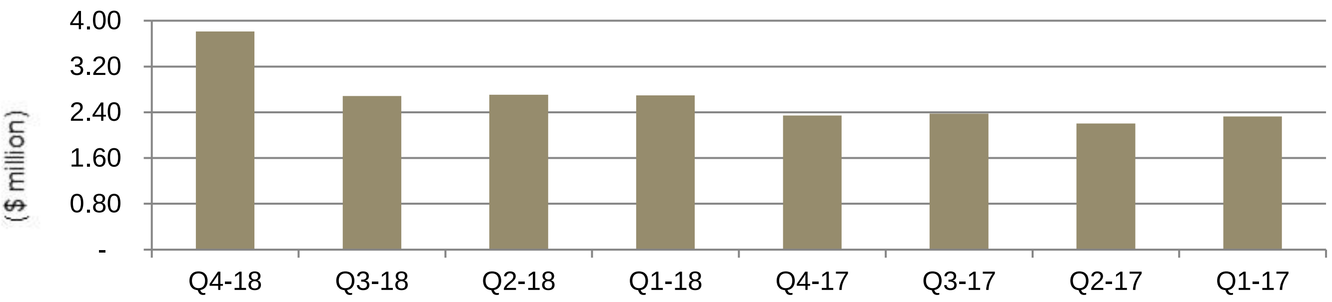
Long term liabilities of $25,288,012 consisted of shareholder loan payable to JSEL, non-current portion of Al Baraka syndicated credit facilities, JS Bank term finance facility, asset retirement obligations related to exploration and development properties and deferred tax liability.

Summary of Quarterly Results

Description	2018				2017			
	Q-4	Q-3	Q-2	Q-1	Q-4	Q-3	Q-2	Q-1
	---------------------$---------------------							
Net revenue	3,813,145	2,685,237	2,707,574	2,696,741	2,345,108	2,379,501	2,205,615	2,324,990
Net profit / (loss)	(2,202,192)	562,274	802,916	846,475	(117,865)	(505,304)	(424,653)	(277,114)
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)	(0.03)	0.01	0.01	0.01	(0.00)	(0.01)	(0.01)	(0.00)
Capital expenditure	1,171,752	1,173,891	1,741,788	592,770	(413,012)	572,146	980,779	273,037
Assets	53,888,746	56,416,111	57,426,195	55,170,275	57,366,408	55,863,665	54,875,500	54,506,053
Long-term liabilities	25,288,012	24,187,846	25,057,475	22,907,689	24,015,241	14,927,027	17,111,219	23,703,563

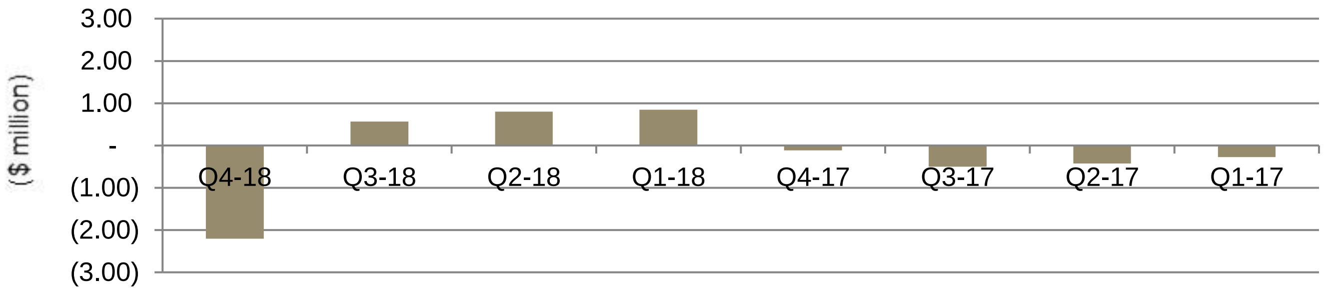
Trend Analysis of Quarterly Results

Net Revenue



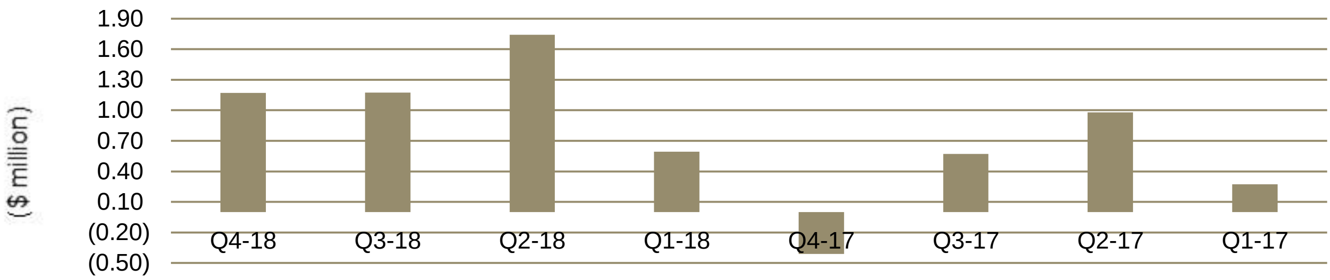
Quarterly revenue indicates a consistent production from Zarghun South and Reti Maru leases. A slight increase in revenue during Q1 through Q3 2018 represents increase in average realized price on account of improvement in international crude oil prices. Significant increase in Q4 2018 is due to adjustment of Zarghun South royalty due to incorporation of royalty processing charges by the operator and recognition of price adjustment for the period July 2018 to December 2018.

Net profit / (loss)



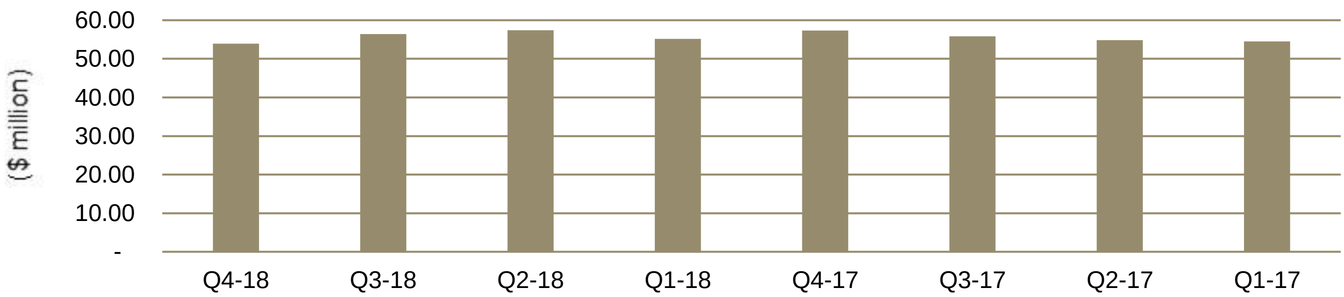
The Company continued to incur losses since inception. The net loss during 2017 is due to increased operating costs and general and administrative expenses. During Q1, Q2 and Q3 2018, the Company reported net profit due to increase in revenue, un-realized exchange gain on the retranslation of foreign currency denominated borrowings and a decrease in general and administrative expenses following management team restructuring in Q3 2017. In Q4 2018, the Company reported a net loss of $2,202,192 mainly due to impairment of oil and gas properties and recognition of deferred tax liability due to reduction in value of PKR denominated tax losses and allowances.

Capital expenditure



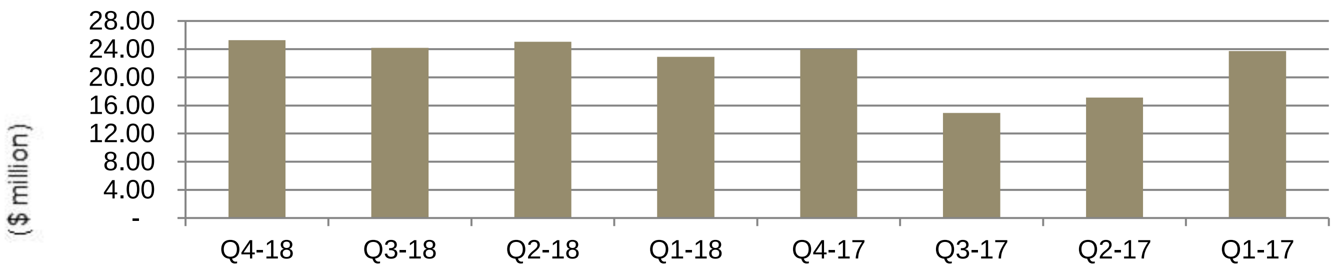
The Company continued to incur significant capital expenditure for the development of its oil and gas properties. Capital expenditure in 2017 and 2018 mainly relates to drilling of exploration wells in Guddu, 3D seismic acquisition in Guddu and development of gas and condensate discoveries in Badin IV South block. The adjustment in Q4 2017 represents the allocation of exploration past costs to Government Holdings (Private) Limited pursuant to the terms of Bolan Petroleum Concession Agreement.

Assets



There has been no significant change in total assets upto Q3 2018. The reduction in Q4 2018 is due impairment of oil and gas properties.

Long term liabilities



The decrease in Q2 and Q3 2017 is due to transfer of current portion of Al Baraka syndicated credit facility, subordinated debentures and shareholder loan to current liabilities. In Q4 2017, the Company reclassified the shareholder loan from current to non-current liability based on a written undertaking from JSEL, pursuant to which the loan shall not be called for repayment for a minimum period of twelve months from the date of approval of the consolidated financial statements of the Company. A slight increase in long term liabilities in Q4 2018 is due to recognition of deferred tax liability and reclassification of short term loan from JSEL as non-current liability.

Fourth Quarter Results and Analysis

Description	Three months ended December 31,		
	2018	2017	Difference
	----------$----------		
Revenue	3,813,145	2,345,108	1,468,037
Net loss	(2,202,192)	(117,865)	(2,084,327)
Weighted no. of outstanding share	69,076,328	69,076,328	-
Earnings / (loss) per share (basic and diluted)	(0.03)	0.00	(0.03)
Capital expenditure	1,171,752	(413,012)	1,584,764
Assets (at December 31)	53,888,746	57,366,408	(3,477,662)
Long term liabilities (at December 31)	25,288,012	24,015,241	1,272,771

Revenue:

The increase in revenue in Q4 2018 compared to Q4 2017 is due to increase in average realized price on account of improvement in international crude oil prices, adjustment of Zarghun South royalty due to incorporation of royalty processing charges by the operator and recognition of price adjustment for the period July 2018 to December 2018.

Net loss:

The significant increase in net loss in Q4 2018 is mainly due to impairment of oil and gas properties and recognition of deferred tax liability due to reduction in value of PKR denominated tax losses and allowances.

Capital expenditure:

The adjustment in Q4 2017 represents the allocation of exploration past costs to Government Holdings (Private) Limited pursuant to the terms of Bolan Petroleum Concession Agreement. The capital expenditure in Q4 2018 represents expenditure incurred on 3D seismic acquisition in Guddu and development of gas and condensate discoveries in Badin IV South block.

Assets:

There reduction in assets during Q4 2018 compared to Q4 2017 is due to impairment of oil and gas properties.

Long term liabilities:

A slight increase in long term liabilities in Q4 2018 compared to Q4 2017 is due to recognition of deferred tax liability and reclassification of short term loan from JSEL as non-current liability.

Financial and Overall Performance Review and Analysis

Review of Financial Results

1. **Net profit / (loss)**

Description	For the year ended December 31,		
	2018	2017	Difference
	----------$----------		
Net profit / (loss)	9,473	(1,324,936)	1,334,409

The Company posted a net profit of $9,437 for the year ended December 31, 2018 compared to a net loss of $1,324,936 in the comparative period.

The net profit for the current year is mainly due to an increase in revenue, un-realized exchange gain on retranslation of foreign currency denominated borrowings and payables, a decrease in general and administrative expenses following management team restructuring in Q3 2017, overall reduction in PKR denominated cost of operations in Pakistan due to significant devaluation of PKR against US Dollar offset by impairment of oil and gas properties and recognition of deferred tax liability due to reduction in value of PKR denominated tax losses and allowances.

Segment breakdown of profit / (loss) for the year ended December 31, 2018 is as follows:

	$
Canada	(1,151,855)
Pakistan	1,161,328

The segment-wise profit / (loss) for the year is mainly attributable to the following:

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

- Net profit of the Pakistan segment is primarily due to an increase in revenue, un-realized exchange gain on foreign currency denominated borrowings and a decrease in general and administrative expenses following management team restructuring in Q3 2017.

2. Net revenue

Description	For the year ended December 31,		
	2018	2017	Difference
	----------$----------		
Sales	12,342,024	10,582,161	1,759,863
Royalty	(439,327)	(1,326,947)	887,620
Net revenue	**11,902,697**	**9,255,214**	**2,647,483**

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

The increase of $1,759,863 in gross revenue compared to the comparative period is due to slight increase in production and increased realized gas price per Mcf due to improvement in international crude oil prices.

During the year ended December 31, 2018 daily gas sales volumes from the Reti-Maru and Zarghun South gas fields averaged approximately 11.50 MMcf and 14.91 MMcf respectively compared to 9.13 MMcf, 15.13 MMcf respectively in the year 2017.

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

Description	For the year ended December 31,		
	2018	2017	Difference
Production in Boe	452,561	442,093	10,468
Price ($ / Boe)[1]	27.27	23.94	3.33

[1]*Refer to non-IFRS financial measures.*

The royalty is calculated at 12.5% of revenue minus gathering, processing and transportation charges.

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

Description	For the year ended December 31,		
	2018	2017	Difference
Production in Boe	452,561	442,093	10,468
Royalty ($ / Boe)[1]	0.97	3.00	(2.03)

The significant reduction in royalty per Boe for the current period is due to a revision of $821,267 recorded in the current period representing historical adjustment in royalty calculation of Zarghun South due to offsetting of royalty processing charges against the gross revenue.

Had there been no historical adjustment in royalty calculation of Zarghun South, the royalty per Boe for the current period would be $2.79.

3. Cost of production

Description	For the year ended December 31,		
	2018	2017	Difference
	----------$----------		
Production costs	2,346,905	2,618,644	(271,739)
Depletion of oil and gas properties	2,668,781	2,827,242	(158,461)
	5,015,686	**5,445,886**	(430,200)

During the year, the JV Partners of Zarghun South lease carried out cost optimization to reduce the fixed field operating costs, which resulted in a significant reduction in production costs during 2018.

The decrease in depletion of oil and gas properties is due to increase in recoverable reserves as at December 31, 2018.

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

Description	For the year ended December 31,		
	2018	2017	Difference
Production in Boe	452,561	442,093	10,468
Production costs ($ / Boe)[1]	5.19	5.92	(0.73)

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

Description	For the year ended December 31,		
	2018	2017	Difference
Production in Boe	452,561	442,093	10,468
Depletion costs ($ / Boe)[1]	5.90	6.40	(0.50)

4. General and administrative expenses

Description	For the year ended December 31,		
	2018	2017	Difference
	----------$----------		
General and administrative expenses	2,177,514	2,826,639	(649,125)

The decrease in general and administrative expenses in the current period is due to management team restructuring carried out in Q3 2017.

Segment breakdown of general and administrative expenses for the year ended December 31, 2018 is as follows:

	$
Canada	655,635
Pakistan	1,521,879

5. Exchange gain - net

Description	For the year ended December 31,		
	2018	2017	Difference
	----------$----------		
Exchange gain - net	3,467,684	959,910	2,507,774

The significant increase in currency translation exchange gain is due to the strengthening of US$ exchange rate parity against PKR. The exchange rate used for the retranslation of PKR-denominated monetary assets and liabilities at December 31, 2018 was 1$ = 139.1 compared to exchange rate of 1$ = 110.5 PKR at December 31, 2017.

6. Finance costs

Description	For the year ended December 31,		
	2018	2017	Difference
	----------$----------		
Interest on amount due to related parties	1,434,671	1,024,977	409,694
Interest on borrowings	1,553,204	1,639,792	(86,588)
Accretion on asset retirement obligation	78,106	76,280	1,826
Interest / (adjustment) on late payment of cash calls to operators	549,111	518,104	31,007
	3,615,092	**3,259,153**	**355,939**

Interest on amounts due to related parties increased during the year due to increase in carrying value of shareholder loan and additional short-term loan of $2 million obtained from the shareholder during the year.

7. Operating netback

Description	For the year ended December 31,		
	2018	2017	Difference
	----------$----------		
Net revenue	11,902,697	9,255,214	2,647,483
Production costs	(2,346,905)	(2,618,644)	271,739
Operating netback	9,555,792	6,636,570	2,919,222
Production in Boe	452,561	442,093	10,468
Operating Netback ($ / Boe)[1]	21.11	15.01	6.10

[1]Refer to non-IFRS financial measures.

Operating netback per Boe for the year ended December 31, 2018 increased by $6.10 compared to the comparative period. This is mainly due to the increase in average realized price in the current period on account of improvement in international crude oil prices and a decrease in production costs per Boe.

Impairment of oil and gas properties

At the reporting date, the market capitalization fell below the carrying value of net assets of the Company, as a result of which the management carried out an impairment test for its cash-generating units in accordance with the accounting policy stated in note 2(xvi-b) of Company's annual audit financial statements for the year ended December 31, 2018 and 2017. The tests were performed using a fair value less cost of disposal methodology using a discounted cash flow model. The fair value of each cash-generating unit was categorized as Level 3 fair value based on the unobservable inputs used. The present value of future cash flows was computed by applying forecasted prices of gas reserves to estimated future production of proved and probable gas reserves, less estimated future expenditures to be incurred in developing and producing the proved and probable reserves. The present value of estimated future net cash flows is computed using an after-tax discount rate of 15%. The discount rate used reflects the specific risks relating to the underlying cash-generating units. As a result of the impairment test, an impairment charge of $3.82 million was recorded. The crude oil forecast prices used to determine the recoverable amount are $64.50/bbl in 2019, $67.90/bbl in 2020, $70.70/bbl in 2021, $73.70/bbl in 2022 and an annual escalation of approximately 2% after 2022.

Estimates of the recoverable amounts are sensitive to discount rate and crude oil prices.

A 1% increase / (decrease) in the discount rate would have resulted in an increase / (decrease) in the impairment charge for the year by $0.13 million / ($0.14 million).

A 5% increase / (decrease) in the crude oil price would have resulted in a (decrease) / increase in the impairment charge for the year by ($0.1 million) / $0.09 million.

Provisions, contingencies and commitments

Contingencies and Commitments

Taxation

The Company is involved in claims and actions arising in the course of the Company's operations and is subject to various legal actions and exposures, including tax positions taken by the Company. Although the outcome of these claims cannot be predicted with certainty, the Company does not expect these matters to have a material adverse effect on the Company's financial position, cash flows or results of operations. If an unfavorable outcome were to occur, there exists the possibility of a material adverse impact on the Company's consolidated net earnings or loss in the period in which the outcome is determined. Accruals for litigation, claims and assessments are recognized if the Company determines that the loss is probable and the amount can be reasonably estimated. The Company believes it has made adequate provision for such legal claims. While fully supportable in the Company's view, some of these positions, including uncertain tax positions, if challenged may not be fully sustained on review.

Financial Commitments

The Company's financial commitments mainly consist of minimum work commitments related to its exploration licenses, approved authorities for expenditure and commitments under non-cancellable operating leases for employee vehicles. The following table summarizes the financial commitments of the Company as at December 31, 2018 and 2017. These financial commitments are expected to be funded through internal cash generation and debt and/or equity financing.

Description	December 31, 2018	December 31, 2017
	-------$-------	
Minimum capital commitments related to exploration licenses	6,124,122	4,487,775
Commitments under approved AFEs	172,723	593,952
Commitment under sale and purchase agreement for the acquisition of EEL	1,000	1,000
Commitment under operating leases		
- Not later than one year	9,680	20,934
- Later than one year and less than five years	-	13,365
Total	**6,307,525**	**5,117,026**

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

Description	2019	2020	2021	Total
	-------$------			
Sanjawi	668,250	94,500	1,755,000	2,517,750
Zamzama North	1,224,000	-	-	1,224,000
Guddu	426,300			426,300
Badin IV North	978,036			978,036
Badin IV South	978,036	-	-	978,036
Total	**4,274,622**	**94,500**	**1,755,000**	**6,124,122**

Going Concern and Liquidity

At December 31, 2018, the Company had current assets of $7.62 million comprising accounts and other receivables of $5.14 million, restricted cash of $1.09 million and cash and cash equivalents of $1.39 million. Total current liabilities were $14.38 million comprising accounts payable and accrued liabilities of $10.47 million and current portion of borrowings and amounts due to related parties of $3.91 million. During the year, the Company reported a net profit of $0.01 million (2017 – net loss of $1.32 million). As at December 31, 2018, the Company has an accumulated deficit of $51.49 million (2017 – $52.91 million). For the year ended December 31, 2018 the Company reported cash flows from operations of $4.24 million. In addition to its ongoing working capital requirements, the Company also had financial commitments as at December 31, 2018 that amounted to $6.31 million. Additional cash resources will be required to exploit the Company's petroleum and natural gas properties.

In addition to the above-mentioned factors, there are a number of additional material uncertainties that 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 uncertainties include the need for additional cash resources to fund its existing operations and for the development of its properties, economic dependence on joint venture 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 internal cash generation from its producing concessions, 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.

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. The principal shareholder has confirmed its commitment to provide financial support to the Company as and when required for a minimum period of twelve months from the date of approval of these consolidated financial statements.

The consolidated financial statements of the Company 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

During the year ended December 31, 2018 stock-based compensation of $20,092 (2017: $3,282) was charged to the consolidated statement of comprehensive income / (loss).

Stock Options

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.

	Year ended December 31, 2018			Year ended December 31, 2017		
	Number of options	Weighted average exercise price		Number of options	Weighted average exercise price	
		$	C$		$	C$
Options outstanding, beginning of year	775,000	0.80	1.00	1,025,000	0.74	1.00
Granted	-	-	-	-	-	-
Exercised	-	-	-	-	-	-
Forfeited	-	-	-	-	-	-
Expired	(725,000)	0.80	1.00	(250,000)	0.74	1.00
Options outstanding, end of year	50,000	0.73	1.00	775,000	0.80	1.00
Options exercisable, end of year	50,000	0.73	1.00	775,000	0.80	1.00

Price		Number outstanding	Weighted average remaining contractual life (years)	Exercisable
$	C$			
0.73	1.00	50,000	1.34	50,000
0.73	1.00	50,000	1.34	50,000

Restricted Share Units

The Company has a restricted share unit plan pursuant to which restricted share units ("RSU") may be granted to directors and officers of the Company. The RSU generally vest over a period of up to three years and expire no more than five years from the date of grant. During the year, the Company granted 186,466 (2017 - 368,086) restricted share units to its directors.

Results of Operations

The following table summarizes the working capital of the Company as at December 31, 2018 as compared to December 31, 2017:

Description	As at December 31, 2018	As at December 31, 2017
	----------$-----------	
Current assets	7,620,409	8,423,626
Current liabilities	(14,386,301)	(20,592,947)
Working capital deficiency	(6,765,642)	(12,169,321)

Contractual Obligations

The following table sets forth the contractual obligations of the Company as at December 31, 2018:

Description	Payments due by period				
	Total	Less than 1 year	1-3 years	4-5 years	After 5 years
	----------$-----------				
Minimum capital commitments related to exploration licenses [1]	6,124,122	4,274,622	1,849,500	-	-
Commitments under outstanding AFEs	172,723	172,723	-	-	-
Operating leases	9,680	9,680	-	-	-
Purchase obligations [2]	1,000	1,000	-	-	-
Other obligations [3]	39,674,063	14,386,051	22,448,468	-	2,839,544
Total contractual obligations	**45,981,588**	**18,844,076**	**24,297,968**	**-**	**2,839,544**

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, 2018.

Transactions with Related Parties

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

Transaction with Majority Shareholder – JS Energy Limited

JS Energy Limited, which is a majority shareholder of JEC, provided financial support to SEPL in the form of an interest-bearing bridge loan and a short-term loan. The loans carry mark-up at the rate of 11% per annum compounded quarterly. The changes in loan balances during the applicable periods and balances outstanding as at December 31, 2018 and December 31, 2017 are as follows:

Description	December 31, 2018	December 31, 2017
	----------$-----------	
Bridge Loan		
Balance payable at beginning of the year	9,602,851	9,424,843
Loan repaid during the year	-	(825,000)
Interest accrued on loan from shareholder	1,102,128	1,003,008
Balance payable at end of the year	**10,704,979**	**9,602,851**

Description	December 31, 2018	December 31, 2017
Short Term Loan		
Balance payable at beginning of the year	-	-
Loan received during the year	2,000,000	-
Interest accrued on loan from shareholder	151,276	-
Balance payable at end of the year	**2,151,276**	**-**

Transaction with Associated Entity – JS Bank Limited

JS Bank is a participant in Al Baraka syndicate credit facility with the participation of PKR 670 million (equivalent $4.82 million). Further, JS Bank has provided a term finance facility of PKR 200 million (equivalent $1.44 million). The changes in loan balance during the applicable periods and balances outstanding as at December 31, 2018 and December 31, 2017 are as follows:

Description	December 31, 2018	December 31, 2017
	----------$----------	
Syndicated Credit Facility		
Balance payable at beginning of the year	5,211,590	4,769,529
Loan received during the year	-	1,557,579
Mark-up accrued during the year	452,330	573,489
Mark-up paid during the year	(425,930)	(509,199)
Principal repaid during the year	(1,210,897)	(892,972)
Exchange gain on retranslation of loan	(881,467)	(286,836)
Balance payable at end of the year	**3,145,626**	**5,211,590**
Term Finance Facility		
Balance payable at beginning of the year	1,786,416	-
Loan received during the year	-	1,848,259
Mark-up accrued during the year	181,267	21,969
Mark-up paid during the year	(157,858)	-
Exchange gain on retranslation of loan	(370,900)	(83,812)
Balance payable at end of the year	**1,438,925**	**1,786,416**

Key Management Personnel

Description	December 31, 2018	December 31, 2017
	----------$----------	
Management salaries and benefits	275,422	506,298
Directors' fees and compensation	88,676	144,811
Total	**364,098**	**651,109**

Future Outlook

The Company's capital expenditure program for 2019 includes:

- development of Ayesha, Aminah and Ayesha North gas and condensate discoveries in Badin IV South block involving installation of a production facility;
- development of Zainab gas and condensate discovery in Badin IV North block;
- drilling of one exploration well in the Badin IV South exploration license; and
- drilling of one exploration well in the Guddu exploration license.

This capital expenditure program is expected to be funded through available cash and internal cash generation.

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

- The Sara and Suri leases;
- The Ayesha, Aminah and Ayesha North gas and condensate discoveries in Badin IV South block; and
- The Zainab gas and condensate discovery in Badin IV North block.

New Accounting Standards and Pronouncements

New standards, amendments and interpretations adopted during the year

IFRS 15 *Revenue from Contracts with Customers* ("IFRS 15")

Effective January 1, 2018, JEC adopted IFRS 15 using the modified retrospective approach. The standard supersedes IAS 18 *Revenue*, IAS 11 *Construction Contracts* and related interpretations.

The Company principally generates revenue from the sale of natural gas and condensate. Revenue associated with the sale of natural gas and condensate is recognized when control is transferred to the buyers. The Company considers control to be transferred when all the following conditions are satisfied:

- the title and physical possession of natural gas and condensate is transferred to the buyer;
- the significant risks and rewards of ownership of natural gas and condensate are transferred to the buyer; and
- the Company has a present right to payment.

Revenue is measured based on the consideration specified in a contract with the customer. The payment terms under the contracts are 30 to 60 days from the month following delivery. JEC does not have any contracts where the period between the transfer of committed supply of natural gas and condensate and payment by the customer exceeds one year. As a result, JEC does not adjust its revenue transactions for the time value of money.

The standard has been applied using the modified retrospective approach. The modified retrospective approach does not require restatement of prior period financial information as it recognizes the cumulative effect as an adjustment to opening retained earnings and applies the standard prospectively. Accordingly, comparative information in the Company's consolidated statement of financial position, consolidated statements of comprehensive income, consolidated statements of changes in equity and consolidated cash flow statements are not restated.

The impacts of the adoption of IFRS 15 as at January 1, 2018 are as follows:

	As reported as at December 31, 2017	Adjustment	Restated Balance as at January 1, 2018
		-----------------$-----------------	
Deferred revenue (note a)	2,632,428	(1,963,041)	669,387
Royalty on deferred revenue	3,179,922	245,381	3,425,303
Deferred tax liability	-	313,355	313,355
Accumulated deficit	(52,908,472)	1,404,305	(51,504,167)

a) Accounting for revenue from Guddu

In the prior periods, revenue from the sale of gas from the Guddu block was recognized on the basis of the gas price determined under the 2009 Petroleum Policy for Conversion Regime and all the surplus proceeds collected from the buyers were recorded as deferred revenue. In conjunction with the adoption of IFRS 15, the Company completed its assessment pursuant to which the expected revenue from the sale of gas from Guddu shall not be less than the price determined under the 2012 Petroleum Policy. Accordingly, upon the adoption of IFRS 15, the cumulative amount of deferred revenue, net of royalty and associated deferred tax liability, has been transferred to the accumulated deficit on January 1, 2018.

IFRS 9 *Financial Instruments* ("IFRS 9")

Effective January 1, 2018, the Company retrospectively adopted IFRS 9, as well as consequential amendments to IFRS 7 *Financial Instruments: Disclosures*. The standard supersedes earlier versions of IFRS 9 and completes the IASB's project to replace IAS 39 *Financial Instruments: Recognition and Measurement*. The adoption of IFRS 9 did not result in any adjustments to the amounts recognized in the Company's consolidated annual audited financial statements for the year ended December 31, 2017.

Classification and Measurement of Financial Instruments

JEC measures its financial assets and financial liabilities at fair value on initial recognition, which is typically the transaction price unless a financial instrument contains a significant financing component. Subsequent measurement is dependent on the financial instrument's classification which in the case of financial assets is determined by the context of the Company's business model and the contractual cash flow characteristics of the financial asset. Financial assets are classified into three categories: measured at amortized cost, fair value through other comprehensive income ("FVTOCI") and fair value through profit and loss ("FVTPL"). Financial liabilities are subsequently measured at amortized cost, other than financial liabilities that are measured at FVTPL or designated as FVTPL where any change in fair value resulting from an entity's own credit risk is recorded as other comprehensive income ("OCI"). JEC does not employ hedge accounting for its risk management contracts currently in place.

Amortized Cost

JEC classifies its cash and cash equivalents, restricted cash, accounts receivable and accrued liabilities, amounts due to related parties and borrowings as measured at amortized cost. The contractual cash flows received from the financial assets are solely payments of principal and interest, if applicable, and are held within a business model whose objective is to collect the contractual cash flows. These financial assets and financial liabilities are subsequently measured at amortized cost using the effective interest method. The carrying values of JEC's cash and cash equivalents, restricted cash, accounts receivable, accounts payable and accrued liabilities, amounts due to related parties and borrowings approximate their fair values.

FVTOCI and FVTPL

JEC does not have any financial assets or financial liabilities designated as measured at FVTOCI or FVTPL.

The adoption of IFRS 9 has resulted in changes to the classification of some of the Company's financial assets but did not change the classification of the Company's financial liabilities. The classification of cash and cash equivalents and restricted cash were the only instruments with changes in their classification. There is no difference in the measurement of these instruments under IFRS 9 due to the short-term and liquid nature of these financial assets.

The following table summarizes the classification categories for JEC's financial assets and liabilities by financial statement line item under the superseded IAS 39 standard and the newly adopted IFRS 9.

Financial Assets	IAS 39	IFRS 9
Cash and cash equivalents	Held for trading (FVTPL)	Amortized cost
Restricted cash	Held for trading (FVTPL)	Amortized cost
Accounts and other receivables	Loans and receivables (Amortized cost)	Amortized cost

Financial Liabilities	IAS 39	IFRS 9
Accounts payable and accrued liabilities	Other financial liabilities (Amortized cost)	Amortized cost
Amounts due to related parties	Other financial liabilities (Amortized cost)	Amortized cost
Borrowings	Other financial liabilities (Amortized cost)	Amortized cost

Impairment of Financial Assets

IFRS 9 also introduces a new model for the measurement of impairment of financial assets based on expected credit losses which replace the incurred losses impairment model applied under IAS 39. Under this new model, JEC's accounts and other receivables are considered collectible within one year or less; therefore, these financial assets are not considered to have a significant financing component and a lifetime expected credit loss ("ECL") and are measured at the date of initial recognition of the accounts receivable. The cash and cash equivalents and restricted cash consist of cash with reputable financial institutions. ECL allowances have not been recognized for these financial assets due to the virtual certainty associated with their collectability.

Within the accounts and other receivables, the Company assesses the lifetime ECL applicable to its commodity product sales receivables at initial recognition and re-assesses the provision at each reporting date. Lifetime ECLs are a probability-weighted estimate of all possible default events over the expected life of a financial asset and are measured as the difference between the present value of the cash flows due to JEC and the cash flows the Company expects to receive. In making an assessment as to whether JEC's financial assets are credit-impaired, the Company considers bad debts that JEC has incurred historically, evidence of a debtor's present financial condition and whether a debtor has breached certain contracts, the probability that a debtor will enter bankruptcy or other financial reorganization, changes in economic conditions that correlate to increased levels of default, and the term to maturity of the specified receivable. The carrying amounts of receivables are reduced by the amount of the ECL through an allowance account and losses are recognized within General and Administrative Expenses in the statements of comprehensive income/(loss).

Based on industry experience, the Company considers financial assets to be in default when the receivable is more than 365 days past due. Once the Company has pursued collection activities and it has been determined that the incremental cost of collection pursuits outweigh the benefits of the collection, the Company derecognizes the gross carrying amount of the asset and the associated allowance from the balance sheet.

There were no material adjustments to the carrying amounts of any of the Company's financial instruments following the adoption of IFRS 9.

New standards, amendments and interpretations not yet adopted

The Company has reviewed new and revised standards and interpretations that have been approved by the IASB. The following table outlines the new accounting pronouncements issued by the IASB that are applicable to, or may have a future impact on, the Company's financial statements. The Company intends to adopt these standards and interpretations, if applicable, when they become effective.

Leases

In January 2016, the IASB issued IFRS 16 *Leases* which replaces the existing leasing standard (IAS 17 *Leases*) and requires the recognition of most leases on the balance sheet. IFRS 16 effectively removes the classification of leases as either finance or operating leases and treats all leases as finance leases for lessees with exemptions for short-term leases where the term is twelve months or less and for leases of low-value items. The accounting treatment for lessors remains the same, which provides the choice of classifying a lease as either a finance or operating lease. IFRS 16 is effective January 1, 2019, with earlier application permitted. The company is currently assessing the impact of this standard.

There are no other standards that are not yet effective and that would be expected to have a material impact on the entity in the current or future reporting periods and on foreseeable future transactions.

Critical Accounting Estimates and Judgements

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 judgement 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 the 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 the 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 judgement 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 the reporting date.

j) Determination of functional currency

The determination of the functional currency of the Company is critical and requires significant judgement, since the recording of transactions and exchange differences arising therefrom are dependent on the functional currency selected.

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) and Canadian Dollar (CAD). 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, 2018**	**December 31, 2017**
	--------------$-----------	
PKR		
Bank balances	223,544	324,307
Accounts and other receivables	587,622	480,215
Accounts payable and accrued liabilities	(3,010,676)	(4,884,968)
Amounts due to related parties	(1,438,925)	(1,786,416)
Borrowings	(7,529,067)	(12,254,810)
Net exposure	**(11,167,502)**	**(18,121,672)**
CAD		
Bank balances	2,955	980
Accounts and other receivables	3,458	2,130
Accounts payable and accrued liabilities	(278,481)	(381,343)
Net exposure	**(272,068)**	**(378,233)**

The following significant exchange rates were applied during the year:

Description	2018	2017
PKR per USD		
Average rate	119.06	105.50
Reporting date rate	139.10	110.50
CAD per USD		
Average rate	1.30	1.30
Reporting date rate	1.36	1.24

If the functional currency, at the reporting date, had fluctuated by 5% against the PKR and CAD with all other variables held constant, the impact on comprehensive income / (loss) for the year would have been $571,979 (2017: $925,995) 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, 2018	December 31, 2017
	-------------$	----------
Fixed rate instruments		
- Borrowings	3,480,752	4,026,055
- Amounts due to related parties	12,868,780	9,615,376
Floating rate instruments		
- Borrowings	7,529,067	12,254,809
- Amounts due to related parties	1,438,925	1,786,416

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 $89,680 (2017: $140,412) 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, 2018	December 31, 2017
	-------------$	---------
Cash at bank	1,388,243	4,523,811
Restricted cash	1,088,573	1,097,351
Accounts and other receivables	5,143,593	2,954,748
Total	**7,620,409**	**8,575,910**

The credit risk on liquid funds is limited because the counterparties 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 the 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	2018	2017
			-----------$-----------	
RBC – Canada	Moody's[1]	A1	48,989	5,891
Meezan Bank Limited	JCR-VIS[2]	AA-	619	842
Bank Alfalah Limited	PACRA[3]	AA+	585	613
Askari Bank Limited	PACRA	AA+	1,239	1,321
JS Bank Limited	PACRA	AA-	70,697	213,186
Silk Bank Limited	JCR-VIS	A-	29	13,764
Al Baraka Bank Pakistan Limited	PACRA	A	2,354,656	5,385,545
Total			**2,476,816**	**5,621,162**

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

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.

The majority of the Company's trade receivables relate to the sale of natural gas to Sui Southern Gas Company Limited ("SSGCL"), a Pakistan state-owned gas transmission company. At December 31, 2018, 92% (December 31, 2017: 87%) of the Company's trade receivables were for gas sales to SSGCL. While determining whether amounts that are past due are collectible, the management assesses the creditworthiness and past payment history of the counterparty, as well as the nature of the past due amount. JEC considers all amounts greater than 90 days to be past due, at which point significant increase in credit risk exists. The lifetime expected credit loss allowances related to the Company's accounts and other receivables was nominal as at and for the years ended December 31, 2018 and 2017. As of December 31, 2018, trade receivables of $1,724,682 (2017: $nil) were past due but not impaired. The aging analysis of these trade receivables is as follows:

Description	December 31, 2018	December 31, 2017
	----------$-----------	
Up to 3 months	2,887,858	1,641,737
3 to 6 months	1,724,682	-
Above 6 months	-	-
Total	**4,612,540**	**1,641,737**

(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 process 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, 2018:

	Less than 6 months	6-12 months	Between 1 and 2 years	Between 2 and 5 years	Over 5 years	Total contractual cash flows	Carrying amount
	$	$	$	$	$	$	$
Accounts payable and accrued liabilities	10,471,909	-	-	-	-	10,471,909	10,471,909
Amounts due to related parties	323,206	308,672	14,858,088	515,606	-	16,005,572	14,307,705
Borrowings	2,253,353	2,156,452	7,329,704	861,523	-	12,601,032	11,009,819
	13,048,468	**2,465,124**	**22,187,792**	**1,377,129**	**-**	**39,078,513**	**35,789,433**

The following are the contractual maturities of financial liabilities as at December 31, 2017:

	Less than 6 months	6-12 months	Between 1 and 2 years	Between 2 and 5 years	Over 5 years	Total contractual cash flows	Carrying amount
	$	$	$	$	$	$	$
Accounts payable and accrued liabilities	13,534,116	-	-	-	-	13,534,116	13,534,116
Amounts due to related parties	78,027	81,205	11,417,280	1,327,929	-	12,904,441	11,401,792
Borrowings	5,973,756	2,059,474	4,614,840	6,059,232	-	18,707,302	16,280,865
	19,585,899	**2,140,679**	**16,032,120**	**7,387,161**	**-**	**45,145,859**	**41,216,773**

There is a material uncertainty about the Company's ability to continue as going concern. See *"Going Concern and Liquidity"* above.

Fair value of financial assets and liabilities

The fair value 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 fair value of cash and cash equivalents, restricted cash, accounts and other receivables, accounts payable, borrowings, accrued liabilities and amounts due to related parties approximate their carrying amount due to the short-term nature of the instruments. The fair value of the Company's borrowings approximates their carrying value as the interest rates charged on these borrowings are comparable to current market rates.

Financial instruments by category

	December 31, 2018	December 31, 2017
	Amortized Cost	
	-----------$-----------	
Financial assets		
Cash and cash equivalents	1,388,243	4,524,499
Restricted cash	1,088,573	1,097,351
Accounts and other receivables	5,143,593	2,954,748
	7,620,409	**8,576,598**
Financial liabilities		
Accounts payable and accrued liabilities	10,471,909	13,534,116
Amounts due to related parties	14,307,705	11,401,792
Subordinated debentures	11,009,819	16,280,865
	35,789,433	**41,216,773**

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 lenders and 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, 2018 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.

Volatility of Crude oil prices

In Pakistan, the price for gas purchased by the GoP is based on a formula linked to the international prices for a basket of Arabian and Persian Gulf crude oil imported into Pakistan. Crude oil prices are affected by, among other things, global economic health and global economic growth, pipeline constraints, regional and international supply and demand imbalances, political developments, compliance or non-compliance with quotas agreed upon by OPEC members, decisions by OPEC not to impose quotas on its members, access to markets for crude oil, and weather.

Through the latter half of 2014 and into the latter half of 2016, world oil prices have declined significantly. A prolonged period of low and/or volatile prices could affect the value of Company's oil and gas properties and the level of spending on growth projects and could result in the curtailment of production from some properties and/or the impairment of that property's carrying value. Accordingly, low crude oil, could have a material adverse effect on Company's business, financial condition, reserves, and may also lead to further impairment of assets.

Obtaining financing

The Company is in the growth phase of its oil and gas operations with limited revenues from two properties and the 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 dependent 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 therefrom. 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 the 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 the production of oil and gas reserves. Abandonment and reclamation of these facilities and the costs associated therewith are 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.

Risk to Information Technologies Systems and Cyber Security

The Company may be negatively affected by cybersecurity incidents or other IT systems disruption. The Company relies heavily on its information technology systems including, without limitation, its networks, equipment, hardware, software, telecommunications, and other information technology (collectively "IT systems"), and the IT systems of its vendors and third party service providers, to operate its business as a whole. Although the Company has not experienced any material losses to date relating to cybersecurity, or other IT systems disruptions, there can be no assurance that the Company will not incur such losses in the future. Despite the Company's efforts to mitigate IT systems security risks, the risk and exposure to these threats cannot be fully mitigated because of, among other things, the evolving nature of cybersecurity threats. As a result, cybersecurity and the continued development and enhancement of controls, processes and practices designed to protect IT systems from cybersecurity threats remain a priority. As these threats continue to evolve, the Company may be required to spend additional resources to continue to modify or enhance protective measures or to investigate and remediate any cybersecurity vulnerabilities. Any cybersecurity incidents or other IT systems disruption could result in operational delays, destruction or corruption of data, security breaches, financial losses from remedial actions, the theft or other compromising of confidential or otherwise protected information, fines and lawsuits, or damage to the Company's reputation. Any such occurrence could have an adverse impact on the Company's financial condition and operations.

Local Legal, Political and Economic Factors

Currently, the Company is undertaking its oil and gas activities exclusively 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' judgements 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 reduced significantly 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, more established companies, which 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 (Pakistan Rupee or Canadian Dollar) financial transactions are translated to United States dollars. This may have a significant effect on profitability 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, judgement, 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, 836,081 restricted share units, 50,000 stock options and 750,000 share purchase warrants outstanding as of the date of this MD&A.

Disclosure Controls and Procedures, and Internal Controls over Financial Reporting

As at December 31, 2018, an evaluation of the effectiveness of 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 Interim Chief Financial Officer ("CFO"). Based on this evaluation, the CEO and the CFO concluded that, as at December 31, 2018, 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, 2018, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external reporting purposes.

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.