JURA ENERGY CORPORATION

MANAGEMENT'S DISCUSSION AND ANALYSIS
FOR THE THREE AND NINE MONTHS ENDED
SEPTEMBER 30, 2018 and 2017

November 28, 2018

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 three and nine months ended September 30, 2018 and 2017 and the Company's financial position as at September 30, 2018. This MD&A is approved by the Board of Directors (the "Board") on November 28, 2018 and should be read in conjunction with the condensed consolidated interim financial statements of the Company for three and nine months ended September 30, 2018 and 2017, annual audit financial statements for the years ended December 31, 2017 and 2016 and the Company's annual MD&A for the years ended December 31, 2017 and 2016.

The condensed consolidated interim financial statements of the Company for the three and nine months ended September 30, 2018 and 2017 have been prepared by management in accordance with the International Financial Reporting Standards ("IFRS") as applicable to the interim financial reports including IAS 34 - Interim Financial Reporting, and should be read in conjunction with the annual audited consolidated financial statements of the Company for the years ended December 31, 2017 and 2016 which have been prepared in accordance with IFRS, as issued by the International Accounting Standards Board ("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 condensed consolidated interim financial statements of the Company, divided by production for the period.

Readers are encouraged to evaluate each adjustment and the reasons the Company considers it appropriate for 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 and the Company's future outlook. 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 three and nine months ended September 30, 2018 and up to the date of this MD&A are as follows:

- The Company reported a net profit for the three and nine months period ended September 30, 2018 of $0.56 million and $2.21 million respectively compared to a net loss of $0.51 million and $1.21 million in the comparative period. The net profit for the current period is mainly due to an increase in revenue, un-realized exchange gain on the retranslation of foreign currency denominated borrowings and payables and a decrease in general and administrative expenses following management team restructuring in Q3 2017;

- Gross profit for the three and nine months period ended September 30, 2018 was $1.44 million and $4.14 million respectively compared to a gross profit of $0.70 million $2.56 million in 2017. This significant increase in gross profit is due to the increase in revenue during the current period;

- Net revenue increased by 13% and 17% during the three and nine months period ended September 30, 2018 compared to the comparative period. The increase in revenue is due to increase in production from Zarghun South and Guddu leases and increase in average realized price on account of improvement in international crude oil prices;

- Production during the three and nine months period ended September 30, 2018 increased by 1% and 5% respectively compared to the three and nine months period ended September 30, 2017. The increase is mainly due to increase in production from the Guddu lease after the commencement of resumption of production from Khamiso and Maru East wells;

- 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; and

- In May 2018, JEC completed a private placement of 3,500 units of new $1,000 subordinated debentures.

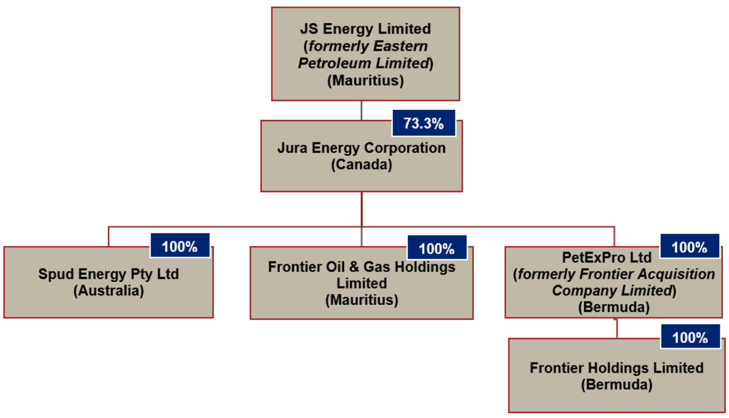
Overview of the Company and Operations

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 & Gas Development Company Limited
Maru lease	10.66%	Oil & Gas Development Company Limited
Maru South lease	10.66%	Oil & 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 & 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 interests range from 10.66% to 60%.

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

There has been no significant change in the status of activities in the exploration licenses and development leases since the filling of annual MD&A for the year ended December 31, 2017.

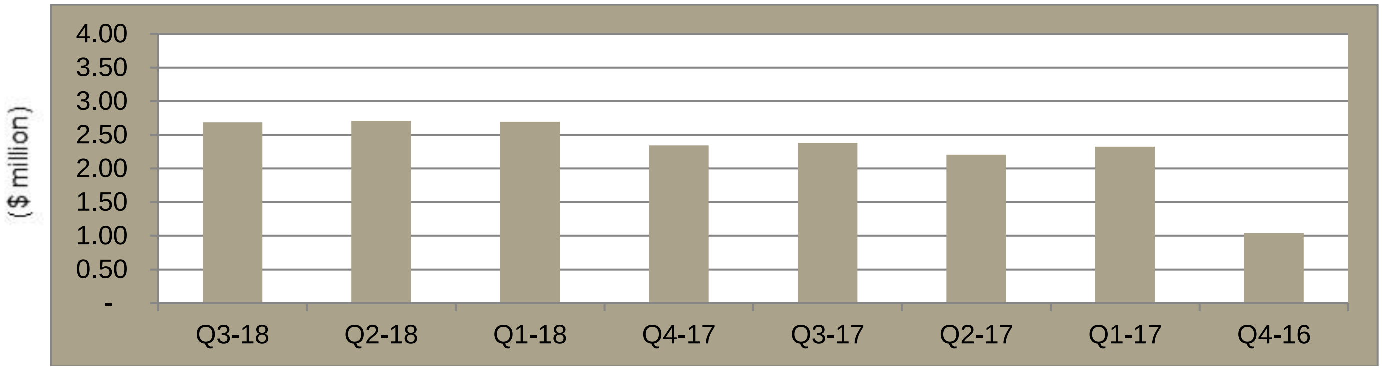
Performance Overview and Financial Analysis

Summary of Quarterly Results

Description	2018			2017				2016
	Q-3	Q-2	Q-1	Q-4	Q-3	Q-2	Q-1	Q-4
	--------------------$--------------------							
Net revenue	2,685,237	2,707,574	2,696,741	2,345,108	2,379,501	2,205,615	2,324,990	1,040,966
Net profit / (loss)	562,274	802,916	846,475	(117,865)	(505,304)	(424,653)	(277,114)	11,073,701
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)	0.01	0.01	0.01	(0.00)	(0.01)	(0.01)	(0.00)	0.16
Capital expenditure	1,173,891	1,741,788	592,770	(413,012)	572,146	980,779	273,037	2,584,330
Assets	56,416,111	57,426,195	55,170,275	57,366,408	55,863,665	54,875,500	54,506,053	53,179,583
Long-term liabilities	24,187,846	25,057,475	22,907,689	24,015,241	14,927,027	17,111,219	23,703,563	25,025,048

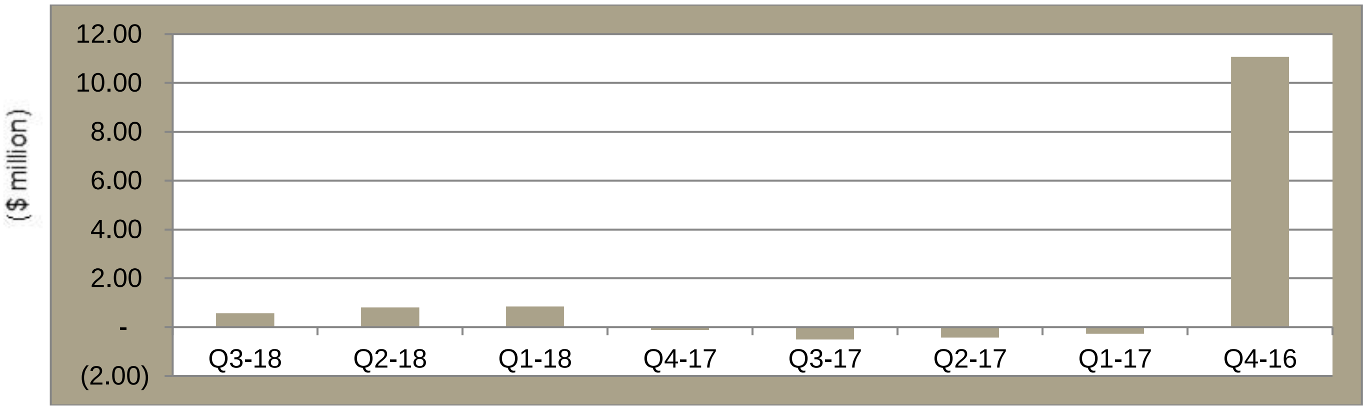
Trend analysis of quarterly information

Net Revenue



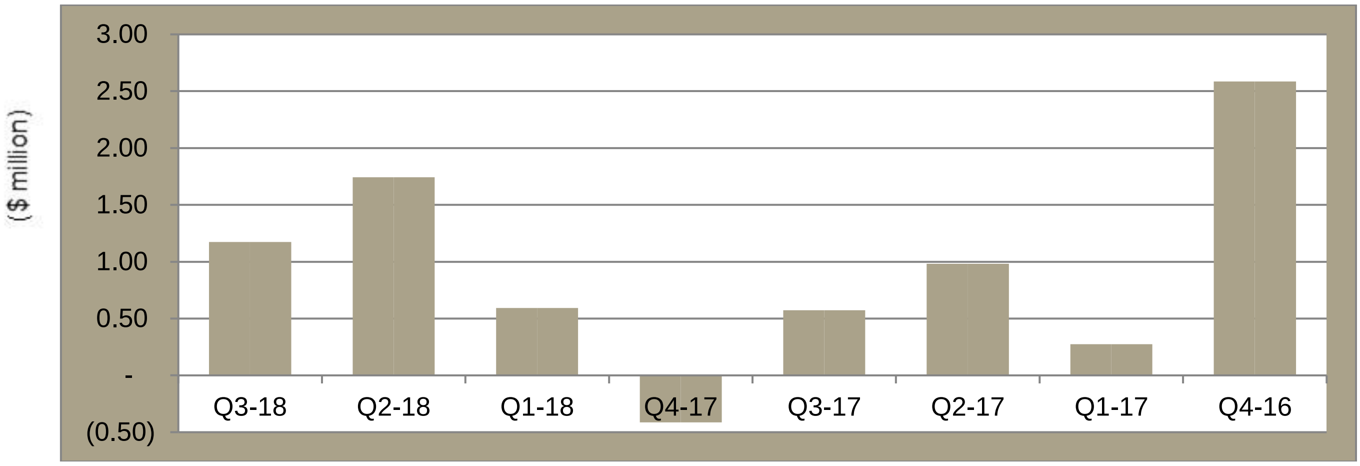
Significant increase in quarterly revenue from Q1 2017 is due to revenue associated with tight gas production from the development well ZS-3 in the Zarghun South lease that commenced production in January 2017 and an increase in average realized price on account of improvement in international crude oil prices.

Net profit / (loss)



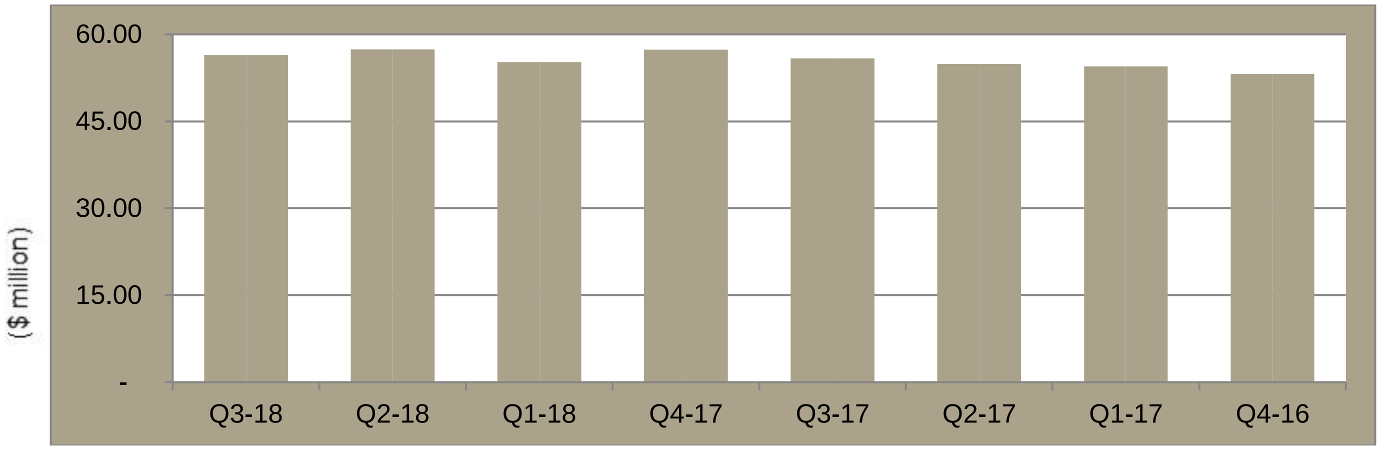
The Company continued to incur losses since inception. In Q4 2016, the Company reported a net profit of $11.07 million. The net profit in Q4 2016 was due to reversal of impairment of Zarghun South following improvement in international crude oil prices and an increase in recoverable reserves after drilling of third development well. The net loss during 2017 is due to increased operating costs and general and administrative expenses. In Q1, Q2 and Q3 2018, the Company reported a net profit of $0.85 million, $0.80 million and $0.56 million respectively. The net profit is mainly 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.

Capital expenditure



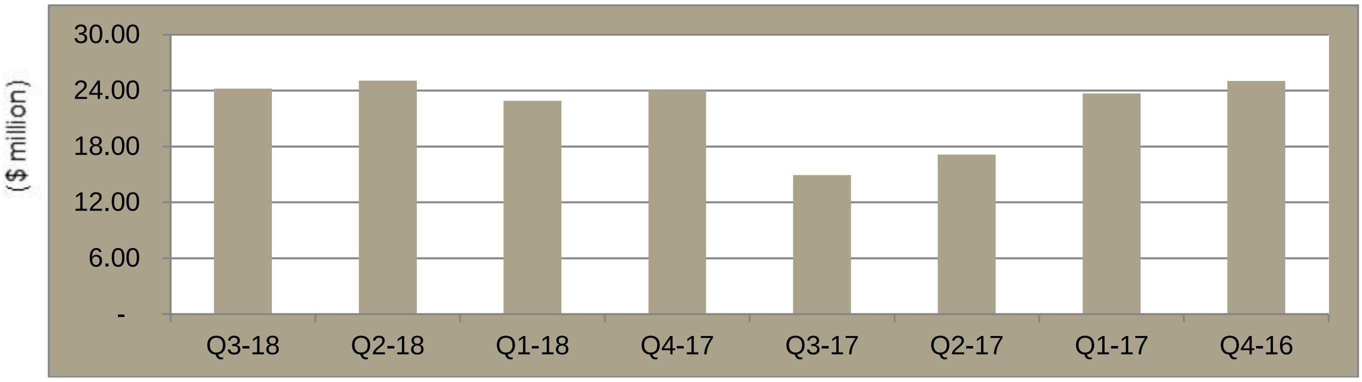
The Company continued to incur significant capital expenditure for the development of its oil and gas properties. Capital expenditure in Q4 2016, Q1 2017, Q2 2017 and Q3 2017 relates to the drilling of development in the Zarghun South lease and the expenditure related to the development of gas and condensate discoveries in Badin IV South exploration license. 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. Capital expenditure in Q1, Q2 and Q3 2018 relates to the drilling of exploration well and 3D seismic acquisition in Guddu exploration license and development of gas and condensate discoveries in Badin IV South exploration license.

Assets



There has been no significant change in total assets since Q4 2016.

Long term liabilities



In Q4 2016 SEPL entered into a fourth supplemental agreement with the shareholder pursuant to which a grace period of 15 months for the repayment of principal and accrued mark-up has been granted by JSEL, which result in its reclassification to a long term liability. 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 for the year ended December 31, 2017.

Financial and Overall Performance Review and Analysis

Review of Financial Results

1. Net profit / (loss)

Description	For the three months period ended September 30,			For the nine months period ended September 30,		
	2018	2017	Difference	2018	2017	Difference
	----------$----------					
Net profit / (loss)	562,274	(505,304)	1,067,578	2,211,665	1,207,071)	3,418,736

The Company reported a net profit of $0.56 million and $2.21 million for the three and nine months period ended September 30, 2018 compared to a net loss of $0.51 million and $1.21 million in the comparative period.

The net profit is mainly 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.

Segment breakdown of profit / (loss) for the three and nine months period ended September 30, 2018 is as follows:

	Three months ended September 30, 2018	Nine months ended September 30, 2018
	$	$
Canada	(230,393)	(689,221)
Pakistan	792,667	2,900,886

The segment-wise profit / (loss) for the period 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 three months period ended September 30,			For the nine months period ended September 30,		
	2018	2017	Difference	2018	2017	Difference
	----------$----------					
Sales	2,958,173	2,720,055	238,118	8,941,318	7,897,058	1,044,260
Royalty	(272,936)	(340,554)	67,618	(851,766)	(986,952)	135,186
Net revenue	**2,685,237**	**2,379,501**	**305,736**	**8,089,552**	**6,910,106**	**1,179,446**

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 $238,118 and $1,044,260 in gross revenue compared to the comparative period is due to an increase in production from Guddu lease after the resumption of production from Khamiso and Maru East wells and an increase in average realized price on account of improvement in international crude oil prices.

During the nine months period ended September 30, 2018 daily gas sales volumes from the Reti-Maru and Zarghun South gas fields averaged approximately 11.48 MMcf and 15.10 MMcf respectively compared to 9.78 MMcf and 14.74 MMcf respectively in 2017.

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

Description	For the three months period ended September 30,			For the nine months period ended September 30,		
	2018	2017	Difference	2018	2017	Difference
	----------$----------					
Production in Boe	110,414	109,303	1,111	341,945	326,558	15,387
Price ($ / Boe)[1]	26.79	24.89	1.90	26.15	24.18	1.97

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

The increase in realized price per Boe is due tight gas production from Zarghun South lease entitled to significantly higher price compared to conventional gas production from Zarghun South and Reti-Maru leases.

The royalty is calculated at 12.5% of the value of petroleum.

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

Description	For the three months period ended September 30,			For the nine months period ended September 30,		
	2018	2017	Difference	2018	2017	Difference
	----------$----------					
Production in Boe	110,414	109,303	1,111	341,945	326,558	15,387
Royalty ($ / Boe)[1]	2.47	3.12	(0.65)	2.49	3.02	(0.53)

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

3. Cost of production

Description	For the three months period ended September 30,			For the nine months period ended September 30,		
	2018	2017	Difference	2018	2017	Difference
	----------$----------					
Production costs	571,591	918,135	(346,544)	1,881,141	2,119,544	(238,403)
Depletion of oil and gas properties	671,542	757,963	(86,421)	2,063,559	2,234,964	(171,405)
	1,243,133	**1,676,098**	**(432,965)**	**3,944,700**	**4,354,508**	**(409,808)**

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

Description	For the three months period ended September 30,			For the nine months period ended September 30,		
	2018	2017	Difference	2018	2017	Difference
	----------$----------					
Production in Boe	110,414	109,303	1,111	341,945	326,558	15,387
Production costs ($ / Boe)[1]	5.18	8.40	(3.22)	5.50	6.49	(0.99)

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

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

Description	For the three months period ended September 30,			For the nine months period ended September 30,		
	2018	2017	Difference	2018	2017	Difference
	----------$----------					
Production in Boe	110,414	109,303	1,111	341,945	326,558	15,387
Depletion costs ($ / Boe)[1]	6.08	6.93	(0.85)	6.03	6.84	(0.81)

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

The decrease in depletion cost per Boe is due to increase in reserves at December 31, 2017.

4. General and administrative expenses

Description	For the three months period ended September 30,			For the nine months period ended September 30,		
	2018	2017	Difference	2018	2017	Difference
	----------$----------					
General and administrative expenses	395,688	628,422	(232,734)	1,160,283	1,927,582	(767,299)

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 three and nine months ended September 30, 2018 is as follows:

	Three months ended September 30, 2018	Nine months ended September 30, 2018
	$	$
Canada	124,574	327,477
Pakistan	270,114	832,806

5. Finance costs – net

Description	For the three months period ended September 30,			For the nine months period ended September 30,		
	2018	2017	Difference	2018	2017	Difference
	----------$----------					
Interest on amount due to related parties	371,200	250,458	120,742	1,033,200	745,662	287,538
Interest on borrowings	459,239	389,166	70,073	1,286,274	1,190,219	96,055
Accretion on asset retirement obligation	19,588	18,966	622	58,517	56,898	1,619
Late payment surcharge on payments	-	-	-	271,605	-	271,605
Currency translation exchange gain	(365,885)	(78,305)	(287,580)	(1,871,247)	(157,692)	1,713,555)
	484,142	**580,285**	**(96,143)**	**778,349**	**1,835,087**	**(1,056,738)**

The increase in interest on amounts due to related parties and borrowings is due to JS Bank term finance facility and enhancement of Al Baraka Syndicate credit facilities completed in Q4 2017.

The significant increase in currency translation exchange gain is due to the strengthening of US$ exchange rate parity against PKR during Q1, Q2 and Q3 2018. The exchange rate used to the retranslation of PKR-denominated monetary assets and liabilities at March 31, 2018, June 30, 2018 and September 30, 2018 was 1$ = 115.4 PKR, 1$ = 121.6 PKR and 1$ = 124.3 PKR respectively (December 31, 2017 1$ = 110.5 PKR).

6. Operating netback

Description	For the three months period ended September 30,			For the nine months period ended September 30,		
	2018	2017	Difference	2018	2017	Difference
	----------$----------					
Net revenue	2,685,237	2,379,501	305,736	8,089,552	6,910,106	1,179,446
Production costs	(571,591)	(918,135)	346,544	1,881,141)	2,119,544)	238,403
Operating netback	2,113,646	1,461,366	652,280	6,208,411	4,790,562	1,417,849
Production in Boe	110,414	109,303	1,111	341,945	326,558	15,387
Operating Netback ($ / Boe)[1]	19.14	13.37	5.77	18.16	14.67	3.49

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

Operating netback per Boe for three and nine months ended September 30, 2018 increased significantly due to increased realized price for tight gas production from Zarghun South lease.

Provisions, contingencies and commitments

Contingencies and Commitments

There has been no material change in contingencies as disclosed in the latest consolidated annual audited financial statements of the Company for the year ended December 31, 2017.

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 September 30, 2018 and December 31, 2017. These financial commitments are expected to be funded through internal cash generation and debt and/or equity financing.

Description	September 30, 2018	December 31, 2017
	-------$-------	
Minimum capital commitments related to exploration licenses	4,168,050	4,487,775
Commitments under approved AFEs	498,293	593,952
Commitment under share purchase agreement for the acquisition of EEL	1,000	1,000
Commitment under operating leases		
- Not later than one year	14,861	20,934
- Later than one year and less than five years	-	13,365
Total	**4,682,204**	**5,117,026**

Going Concern and Liquidity

At September 30, 2018, the Company had current assets of $6.05 million comprising accounts and other receivables of $4.81 million, restricted cash of $1.10 million and cash and cash equivalents of $0.14 million. Total current liabilities were $15.26 million comprising accounts payable and accrued liabilities of $8.89 million and current portion of borrowings and amounts due to related parties of $6.37 million. During the nine months ended September 30, 2018 the Company reported a net profit of $2.21 million (September 30, 2017– net loss of $1.21 million). As at September 30, 2018, the Company has an accumulated deficit of $48.73 million

(December 31, 2017– $52.91 million). In addition to its ongoing working capital requirements, the Company also has financial commitments as at September 30, 2018 that amounted to $4.68 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.

During 2016, SEPL entered into two Musharaka Agreements with Al Baraka Bank (Pakistan) Limited ("Al Baraka"), pursuant to a syndicated credit facility arrangement (the "Syndicated Credit Facility"), as lead arranger, in the amount of up to PKR 1,060 million (approximately $8.53 million).

In February 2017, SEPL entered into a third Musharaka Agreement in respect of the Zarghun South-3 development well under the Syndicated Credit Facility, in the amount of up to PKR 170 million (approximately $1.36 million) resulting in an increase in the Syndicated Credit Facility from PKR 1,060 million (approximately $8.53 million) to PKR 1,230 million (approximately $9.89 million).

In August 2017, SEPL entered into a supplemental third Musharaka Agreement in respect of the Zarghun South-3 development well under the Syndicated Credit Facility, resulting in an increase in the Syndicated Credit Facility from PKR 1,230 million (approximately $9.89 million) to PKR 1,530 million (approximately $12.31 million).

The Syndicated Credit Facility carries mark-up at the rate of 3-month Karachi Interbank Offered Rate ("KIBOR") plus 2.75%. The principal is repayable in sixteen equal quarterly installments in arrears, commencing fifteen months after January 19, 2016, the date of the first disbursement, except for the third Musharaka Agreement, the principal of which is repayable in ten equal quarterly installments in arrears commencing November 14, 2018.

In November 2017, SEPL entered into a term finance facility with JS Bank Limited (the "JS Bank Facility") in the amount of up to PKR 200 million (approximately $1.61 million). The facility carries mark-up at the rate of 3-month Karachi Interbank Offered Rate ("KIBOR") plus 2.75%. The principal is repayable in twelve equal quarterly installments in arrears, commencing fifteen months after November 14, 2017, the date of the first disbursement.

In April 2018, SEPL, JEC and JS Energy Limited ("JSEL") *(formerly Eastern Petroleum Limited)*, the principal shareholder, entered into a short-term loan agreement for an amount of $2 million. Further, in May 2018, the Company completed the private placement of 3,500 units. Each unit comprised a subordinated debenture in the principal amount of $1,000 carrying interest at the rate of 11% per annum and 200 warrants exercisable at a price of C$0.15 per common share of the Company. Interest is payable in arrears in equal semi-annual payments on April 30 and on October 31 each year. The repayment of debentures will fall due on April 30, 2020 or an earlier date at the option of the Company.

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 financial statements.

The condensed consolidated interim 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.

Results of Operations

The following table summarizes the working capital of the Company as at September 30, 2018 as compared to December 31, 2017:

Description	As at September 30, 2018	As at December 31, 2017
	----------$-----------	
Current assets	6,051,433	8,423,626
Current liabilities	(15,258,210)	(20,592,947)
Working capital deficiency	(9,206,777)	(12,169,321)

Contractual Obligations

The following table sets forth the contractual obligations of the Company as at September 30, 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]	4,168,050	2,318,550	1,849,500	-	-
Commitments under outstanding AFEs	498,293	498,293	-	-	-
Operating leases	14,861	14,861	-	-	-
Purchase obligations [2]	1,000	1,000	-	-	-
Other obligations [3]	39,446,056	15,258,210	20,695,819	-	3,492,027
Total contractual obligations	**44,128,260**	**18,090,914**	**22,545,319**	**-**	**3,492,027**

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 September 30, 2018.

Transactions with Related Parties

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

Transactions with majority shareholder

JSE 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 September 30, 2018 and December 31, 2017 are as follows:

Description	September 30, 2018	December 31, 2017
	----------$-----------	
Bridge Loan		
Balance payable at beginning of the period	9,602,851	9,424,843
Loan repaid during the period	-	(825,000)
Interest accrued on loan from shareholder	793,464	1,003,008
Balance payable at end of the period	**10,396,315**	**9,602,851**

Description	September 30, 2018	December 31, 2017
Short Term Loan		
Balance payable at beginning of the period	-	-
Loan received during the period	2,000,000	-
Interest accrued on loan from shareholder	93,238	-
Balance payable at end of the period	**2,093,238**	**-**

Transactions 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 $5.39 million). Further, JS Bank has provided a term finance facility of PKR 200 million (equivalent $1.61 million). The changes in loan balance during the applicable periods and balances outstanding as at September 30, 2018 and December 31, 2017 are as follows:

Description	September 30, 2018	December 31, 2017
	----------$----------	
Syndicated Credit Facility		
Balance payable at beginning of the period	5,211,590	4,769,529
Loan received during the period	-	1,557,579
Mark-up accrued during the period	397,731	573,489
Mark-up paid during the period	(325,314)	(509,199)
Principal repaid during the period	(829,047)	(892,972)
Exchange gain on retranslation of loan	(511,088)	(286,836)
Balance payable at end of the period	**3,943,872**	**5,211,590**
Term Finance Facility		
Balance payable at beginning of the period	1,786,416	-
Loan received during the period	-	1,848,259
Mark-up accrued during the period	146,498	21,969
Mark-up paid during the period	(116,547)	-
Exchange gain on retranslation of loan	(200,869)	(83,812)
Balance payable at end of the period	**1,615,498**	**1,786,416**

Key management personnel

Description	Three months ended		Nine months ended	
	September 30, 2018	September 30, 2017	September 30, 2018	September 30, 2017
	----------$----------			
Management salaries and benefits	63,150	209,053	189,450	437,505
Directors' fees and compensation	22,681	20,766	66,154	127,189
Total	**85,831**	**229,819**	**255,604**	**564,694**

Future Outlook

The Company's capital expenditure program for 2018 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; and
- drilling of one exploration well in the Badin IV South exploration license.

This capital expenditure program is expected to be funded through available cash, internal cash generation and proceeds of the short-term loan agreement with JSEL.

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.

Significant Accounting Policies

The accounting policies adopted in the preparation of the condensed consolidated interim financial statements are consistent with those followed in the preparation of the Company's consolidated annual audited financial statements for the year ended December 31, 2017 except for the change in accounting policies pursuant to the adoption of new and amended standards as set out below:

- IFRS 15 Revenue from Contracts with Customers; and
- IFRS 9 Financial Instruments

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

Effective January 1, 2018, JEC retrospectively adopted IFRS 15*.* 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 the 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 is 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 condensed consolidated statement of financial position, condensed consolidated statements of comprehensive income, condensed consolidated statements of changes in equity and condensed 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
Accumulated deficit	(52,908,472)	1,963,041	(50,945,431)

a) Accounting for revenue from Guddu block

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 and all the surplus proceeds collected from the buyers was 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 block 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 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 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, and long-term debt as measured at amortized cost. The contractual cash flows received from the financial assets are solely payments of principal and interest 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 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.

Critical Accounting Estimates and Judgments

The preparation of the condensed consolidated interim financial statements in conformity with approved accounting standards requires the use of certain critical accounting estimates. It also requires management to exercise its judgement in the process of applying the Company's accounting policies. Estimates and judgments are continually evaluated and are based on historical experience including the expectation of future events that are believed to be reasonable under the circumstances.

Estimates and judgements made by the management in the preparation of condensed consolidated interim financial statements for the three and nine months ended September 30, 2018 are the same as those used in the preparation of Company's consolidated annual audited financial statements for the year ended December 31, 2017.

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 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.

(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.

(iv) Credit risk

Credit risk is the risk of financial loss to JEC, if a counterparty to a product sales contract or financial instrument fails to meet its contractual obligations. JEC is exposed to credit risk with respect to its cash and cash equivalents, restricted cash and accounts and other receivables. However, the default risk is considered very low for all of the Company's financial instruments due to the external credit ratings of its counterparties. Majority of the Company's trade receivables relate to the sale of natural gas to Sui Southern Gas Company Limited ("SSGCL"), a state-owned gas transmission company. At September 30, 2018, 91% (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. At September 30, 2018, $1.61 million of accounts receivable are past due. The lifetime ECL allowances related to the Company's accounts and other receivables was nominal as at and for the periods ended September 30, 2018 and 2017.

(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 protocol to ensure availability of funds, and to take appropriate measures for new requirements.

This interim MD&A do not include all financial risk management information and disclosures required in the annual MD&A and should be read in conjunction with the Company's consolidated annual audit financial statements and annual MD&A for the years ended December 31, 2017 and 2016.

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.

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, 2017 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, 50,000 stock options, 554,552 restricted share units 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

Based on the evaluation of the design and operating effectiveness of the Company's disclosure controls and procedures ("DC&P") and internal controls over financial reporting ("ICFR"), the Interim Chief Executive Officer and the Interim Chief Financial Officer concluded that the Company's DC&P and ICFR were effective as at September 30, 2018.

During the three months ended September 30, 2018, there have been no changes made to the Company's ICFR that materially affected or are reasonably likely to materially affect, it's ICFR.

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.