Questfire Energy Corp. – Financial and Operating Highlights

	Three months ended December 31,		Year ended December 31,	
	2016	2015	**2016**	2015
Financial				
Oil and natural gas sales	**$ 10,445,951**	$ 9,405,900	**$ 32,180,438**	$ 40,717,011
Funds flow from operations [(1)]	**2,550,831**	2,627,473	**4,833,132**	11,543,473
Per share, basic	**0.13**	0.15	**0.27**	0.67
Per share, diluted	**0.11**	0.11	**0.21**	0.48
Income (loss)	**2,752,322**	(1,152,161)	**(7,528,123)**	(10,386,781)
Per share, basic	**0.14**	(0.07)	**(0.42)**	(0.60)
Per share, diluted	**0.12**	(0.07)	**(0.42)**	(0.60)
Capital expenditures	**230,858**	82,743	**650,489**	4,955,048
Proceeds from property dispositions	**$ 8,352,653**	$ -	**10,610,040**	-
Working capital deficit *(end of period)* [(2)]			**41,325,801**	9,653,400
Long-term contract obligation *(end of period)* [(3)]			**13,760,534**	14,155,697
Long-term bank debt *(end of period)*			**-**	41,406,473
Shareholders' equity *(end of period)*			**$ 12,715,156**	$ 14,251,344
Shares outstanding *(end of period)*				
Class A			**22,822,401**	17,318,001
Class B			**-**	550,440
Options outstanding *(end of period)*			**3,133,500**	3,566,000
Weighted-average basic shares outstanding	**19,232,575**	17,318,001	**17,799,260**	17,318,001
Weighted-average diluted shares outstanding	**23,473,125**	17,318,001	**17,799,260**	17,318,001
Class A share trading price				
High	**$ 0.59**	$ 1.44	**$ 0.74**	$ 1.95
Low	**0.24**	0.30	**0.24**	0.30
Close	**$ 0.34**	$ 0.59	**$ 0.34**	$ 0.59
Operations [(4)]				
Production				
Natural gas *(Mcf/d)*	**20,746**	23,245	**21,008**	21,741
Natural gas liquids (NGL) *(bbls/d)*	**695**	674	**706**	647
Crude oil *(bbls/d)*	**368**	512	**424**	606
Total *(boe/d)*	**4,521**	5,060	**4,631**	4,877
Benchmark prices				
Natural gas				
AECO *(Cdn$/GJ)*	**$ 2.94**	$ 2.34	**$ 2.05**	$ 2.55
Crude oil				
WTI *(US$/bbl)*	**49.29**	42.18	**43.32**	48.80
Canadian Light *(Cdn$/bbl)*	**60.76**	52.55	**52.79**	57.45
Average realized prices [(5)]				
Natural gas *(per Mcf)*	**3.27**	2.57	**2.30**	2.78
NGL *(per bbl)*	**34.97**	31.74	**29.16**	34.24
Crude oil *(per bbl)*	**58.30**	41.02	**44.88**	47.89
Operating netback *(per boe)* [(6)]	**11.28**	6.89	**6.45**	8.48
Funds flow netback *(per boe)* [(6)]	**$ 6.13**	$ 5.64	**$ 2.85**	$ 6.49

(1) See "Funds flow from operations" under "Critical Accounting Judgments, Estimates and Policies".

(2) Working capital deficit includes risk management contract and convertible Class B share liabilities of $2,957,743 and $Nil, respectively (December 31, 2015 – risk management contract assets of $Nil and convertible Class B share liability of $5,086,857). Excluding this, the working capital deficit would be $38,368,058 (December 31, 2015 – $4,566,543).

(3) Long-term contract obligation excludes current portion of $395,163 (December 31, 2015 – $344,448), which is included in working capital deficit.

(4) For a description of the boe conversion ratio, see "Basis of Barrel of Oil Equivalent".

(5) Before hedging.

(6) See "Non-GAAP measures".

2016 Corporate Highlights

- Achieved average production of 4,631 boe per day for the year and 4,521 boe per day for the fourth quarter, 76 percent natural gas. The average production for 2016 is within 5 percent of the 4,877 boe per day produced in 2015 despite having no drilling activity in 2016, underscoring the benefits of the Corporation’s low-decline production base.
- Generated a sharply improved fourth quarter operating netback of $11.28 per boe compared to $6.89 per boe in the fourth quarter of 2015 and $7.84 per boe in the third quarter of 2016.
- Achieved funds flow from operations of $4.8 million ($0.27 per basic share) on sales of $32.2 million during 2016. Although full-year funds flow was down significantly from 2015, fourth-quarter 2016 funds flow from operations of $2.6 million was essentially unchanged from the fourth quarter of 2015.
- Minimized capital spending with no new drilling, resulting in total capital expenditures of $650,489.
- Incurred operating costs of $10.98 per boe in the fourth quarter and $10.46 per boe in the full year. Annual operating costs per unit of production declined by 11 percent from 2015.
- Incurred general and administrative (G&A) costs of $4.4 million for the year, representing a 15 percent reduction from 2015.
- Revised the maturity of the Corporation’s bank facility to May 31, 2017 and amended the terms to include a revised $28 million operating and syndicated facility plus an $8.1 million supplemental facility.

President’s Message

Two-thousand sixteen marked the third year of a significant downturn for the oil and natural gas industry, largely driven by weak commodity prices. Rather than experiencing a recovery in oil and gas prices as widely expected, the first half of 2016 saw prices for both oil and gas continue to drop to 20-year lows. This hit Questfire particularly hard as we had virtually no commodity price hedges for the first half of 2016. Along with reduced commodity prices came downward revisions to our senior bank borrowing base.

In response to these significant challenges our strategy, as always, was to work hard to make the best of a tough situation. Over the year we sold approximately 120 boe per day of non-core production, generating proceeds of approximately $10.6 million, all of which was applied to reduce debt. We minimized capital spending which resulted in no new drilling and only $650,489 of capital spending on mandatory maintenance and miscellaneous projects. We also continued to focus on cost reductions, achieving a 15 percent reduction in gross G&A costs and an 11 percent reduction in unit operating costs over 2015. The Questfire management and field operations team worked hard to reduce all downtime and maintain maximum production while minimizing spending. Along with the low-decline nature of our production base, this held the year-over-year decline in average annual production to just 5 percent. We are very satisfied with this result given no drilling, 120 boe per day of asset sales and very low capital spending.

The second half of 2016 saw slow and steady improvement in commodity prices and, as a result, essentially all $4.8 million of our funds flow from operations for the year was generated in the second half of 2016. In December, our bank facility was extended to May 31, 2017 with a $28 million conforming and an $8.1 million supplemental facility. With the fourth quarter's sharply improved operating netback, the continued nearly flat production, the higher realized pricing for all commodities and the essentially flat funds flow from operations from the fourth quarter of 2015, we are optimistic that Questfire's overall position will continue to improve.

The outlook for commodity prices is positive for 2017 and beyond. The improvement in pricing is happening at a slow pace compared to past recoveries, but the fundamentals are in place for further gains. Questfire's goals for 2017 include continued reduction in overall debt and achieving an extension of banking facilities beyond May 31, 2017. With continued debt reduction and improvement in commodity prices, we expect to return to drilling and growth in the second half of 2017.

On behalf of the Board of Directors,

(Signed) "Richard Dahl"

Richard H. Dahl
President and Chief Executive Officer
April 24, 2017

Management's Discussion and Analysis

This management's discussion and analysis (MD&A) of operating and financial results of Questfire Energy Corp. ("Questfire" or the "Corporation") is dated April 24, 2017 and is based on currently available information. It should be read in conjunction with the audited financial statements and accompanying notes for the years ended December 31, 2016 and 2015. Unless otherwise noted, all financial information is presented in Canadian dollars, and is in accordance with International Financial Reporting Standards (IFRS) as issued by the International Accounting Standards Board (IASB), interpretations of the International Financial Reporting Interpretations Committee (IFRIC), and with Canadian generally accepted accounting principles (GAAP) as set out in Part 1 of the Chartered Professional Accountants Canada Handbook – Accounting. These documents, along with other statutory filings, including the Corporation's Annual Information Form, are available on SEDAR at www.sedar.com and on the Corporation's website at www.questfire.ca.

Refer to the end of the MD&A for commonly used abbreviations.

Readers should read "Forward-Looking Statements" at the end of the MD&A, which explains the basis for and limitations of statements throughout this report that are not historical facts and may be considered "forward-looking statements" under securities regulations.

Description of Business

The Corporation is engaged in the acquisition, exploration, development and production of oil and natural gas reserves in Canada. The Corporation's focus is to generate and develop its own prospects, acquire oil and natural gas properties directly and/or through farm-in, and participate with joint venturers and other industry partners in oil and natural gas exploration and development in Alberta. Questfire is traded on the TSX Venture Exchange under the symbol Q.A.

Financial and Operating Results

Production

	Three months ended December 31,		Year ended December 31,	
	2016	2015	**2016**	2015
Daily average volume				
Natural gas *(Mcf/d)*	**20,746**	23,245	**21,008**	21,741
NGL *(bbls/d)*	**695**	674	**706**	647
Crude oil *(bbls/d)*	**368**	512	**424**	606
Total sales *(boe/d)*	**4,521**	5,060	**4,631**	4,877
Total sales *(boe)*	**415,937**	465,534	**1,695,124**	1,779,933
Production weighting				
Natural gas	**76%**	77%	**76%**	74%
NGL	**16%**	13%	**15%**	13%
Crude oil	**8%**	10%	**9%**	13%
	100%	100%	**100%**	100%

Production for the year and the fourth quarter was only slightly lower than in the comparative periods due to the low-decline, long-life nature of Questfire's production base. Production declines are due to lost production from asset sales, natural production declines, shut-in production and TCPL restrictions. NGL production increased from the comparative periods as a result of higher liquid recoveries in Westerose.

Sales

	Three months ended December 31,		Year ended December 31,	
	2016	2015	**2016**	2015
	$	$	**$**	$
Natural gas	**6,236,118**	5,505,749	**17,680,096**	22,037,826
NGL	**2,236,127**	1,968,139	**7,535,720**	8,085,658
Crude oil	**1,973,706**	1,932,012	**6,964,622**	10,593,527
Total	**10,445,951**	9,405,900	**32,180,438**	40,717,011
Average realized prices before hedging				
Natural gas *($/Mcf)*	**3.27**	2.57	**2.30**	2.78
NGL *($/bbl)*	**34.97**	31.74	**29.16**	34.24
Crude oil *($/bbl)*	**58.30**	41.02	**44.88**	47.89
Combined average *($/boe)*	**25.11**	20.20	**18.98**	22.88

The Corporation, like almost all of the upstream oil and natural gas sector in Western Canada, experienced lower prices for all oil and natural gas products in the year ended December 31, 2016 than in the prior year's comparative period. Improved pricing in the fourth quarter, however, resulted in higher quarter-over-quarter sales revenue from each commodity despite slightly lower natural gas and crude oil production.

The timing of market rebalancing for energy commodities remains unknown. Over the short term, the Corporation anticipates continued elevated price volatility. On the oil side, a significant factor is the unknown impact of renewed drilling activities for shale oil wells in the United States, as well as global

inventory levels. It is expected that there will be continued price volatility for at least the next several quarters as the various dynamics play out, which may not provide substantially higher realized prices for Questfire until 2018 or later.

Realized commodity prices changed in step with the applicable underlying price benchmark after factoring in the U.S. to Canadian currency exchange rate. Questfire's natural gas production has an average heating value of approximately 39 megajoules per cubic metre, realizing a price premium over gas with standard heating content. Questfire's NGL is comprised approximately 47 percent of condensate, the highest-priced NGL. All of this is favourable to the Corporation's average realized prices.

Royalties

	Three months ended December 31,		**Year ended December 31,**	
	2016	2015	**2016**	2015
	$	$	**$**	$
Royalties	**659,435**	481,399	**1,667,597**	2,945,794
Per boe	**1.58**	1.03	**0.98**	1.66
Percentage of sales	**6.3%**	5.1%	**5.2%**	7.2%

Questfire's royalty burden includes Crown, Indian, gross over-riding and freehold royalties applicable on the Corporation's production sales.

The royalty rate as a percentage of sales was lower in 2016 than in 2015 due to lower commodity reference pricing used by the Alberta government to calculate royalties. The fourth quarter royalty rate was higher than in the fourth quarter of 2015 due to the rebound in commodity prices.

The Government of Alberta released its royalty review report on January 29, 2016, which contained highlights of a proposed Modernized Royalty Framework (MRF) that became effective on January 1, 2017. The highlights include no changes to the royalty structure of wells drilled prior to 2017 for a 10-year period, the replacement of royalty credits/holidays on conventional wells by a revenue-minus-cost framework with a post-payout royalty rate based on commodity prices, and a neutral effect on the internal rate of return of any given play, compared to the current royalty framework's varying impacts.

Production and Operating Expense

	Three months ended December 31,		**Year ended December 31,**	
	2016	2015	**2016**	2015
	$	$	**$**	$
Production and operating expense	**4,565,214**	5,240,410	**17,732,605**	20,988,872
Per boe	**10.98**	11.26	**10.46**	11.79

Production and operating expenses decreased on a total and per-boe basis from the comparative periods in 2015 due to concentrated field efforts throughout the Corporation's properties to continue reducing operating costs, new wells at Morningside coming on production during the fourth quarter of 2015 with lower per-boe operating costs, as well as prior-period cost recoveries resulting from a working-interest partner audit settlement. Management continues to look at production and operating costs to identify additional efficiencies. The results from these current and future efforts are unknown and may not be significant due to the extent of reductions achieved to date, increased pricing pressures from suppliers, as well as the magnitude of fixed costs such as property taxes and lease rentals.

Transportation Expense

	Three months ended December 31,		Year ended December 31,	
	2016	2015	**2016**	2015
	$	$	**$**	$
Transportation expense	**528,582**	475,739	**1,849,075**	1,685,686
Per boe	**1.27**	1.02	**1.09**	0.95

Transportation expense in the 2016 reporting periods was higher than in the comparative periods in 2015 due to a change in marketers for a portion of the Corporation's natural gas production, which occurred at the start of the fourth quarter of 2015 as Questfire took advantage of an opportunity to increase its natural gas pricing premium over benchmarks.

Risk Management

Questfire's cash flow is highly variable, in large part because oil and natural gas are commodities whose prices are determined by worldwide and/or regional supply and demand, transportation constraints, weather conditions, availability of alternative energy sources and other factors, all of which are beyond Questfire's control. World prices for oil and natural gas have fluctuated widely in recent years.

The substantial downward shift in commodity pricing that began during the fourth quarter of 2014 continued in 2016. Crude oil and natural gas prices trended even lower in the first half of the year. During the fourth quarter of 2016, prices for intra-Alberta natural gas as well as crude oil increased slightly.

If crude oil and natural gas prices decline significantly from current levels and remain low for an extended period, the carrying value of Questfire's assets could be subject to impairment charges, future capital spending could be reduced, causing projects to be delayed or cancelled, and production could be curtailed, among other effects.

Management of cash flow variability is an integral component of the Corporation's business strategy. Business conditions are monitored regularly and reviewed with the Board of Directors to establish risk management guidelines used by management in carrying out the Corporation's strategic risk management program.

The Corporation has elected not to use hedge accounting and, accordingly, the fair value of the financial contracts is recorded at each period-end. The fair value may change substantially from period to period depending on commodity forward strip prices for the financial contracts outstanding at the balance sheet date. The change in fair value from period-end to period-end is reflected in the income for that period. As a result, income may fluctuate considerably.

At December 31, 2016, Questfire had the following risk management contracts, with a total mark-to-market liability of $2,957,743:

Period	Commodity	Type of contract	Notional quantity	Pricing point	Contract price
May 1/16 - Dec. 31/17	Natural Gas	Swap	5,000 GJ/d	AECO 7A	Cdn$2.010/GJ
May 1/16 - Mar. 31/17	Natural Gas	Swap	2,500 GJ/d	AECO 7A	Cdn$1.910/GJ
May 1/16 - Mar. 31/17	Natural Gas	Swap	2,500 GJ/d	AECO 7A	Cdn$1.875/GJ

Risk management contracts are considered financial instruments, and the resulting derivative financial asset or liability was recorded on the Corporation's balance sheet, with the unrealized gain or loss being recorded on the statement of loss and comprehensive loss.

	Three months ended December 31,		Year ended December 31,	
	2016	2015	**2016**	2015
	$	$	**$**	$
Realized gain (loss) on risk management contracts	**(823,087)**	831,249	**(484,037)**	2,624,507
Per boe	**(1.98)**	1.79	**(0.29)**	1.47
Unrealized loss on risk management contracts	**(492,007)**	(676,649)	**(2,957,743)**	(3,390,491)
Per boe	**(1.18)**	(1.45)	**(1.74)**	(1.90)

The realized loss on risk management contracts during the three months ended December 31, 2016 was due to natural gas commodity prices being higher than the swap contract price. The unrealized loss for the same period was a result of increased natural gas 2017 strip prices during the quarter.

The realized losses on risk management contracts during the year ended December 31, 2016 were due to average natural gas commodity prices being higher than the swap contract price. The unrealized loss for the same period was a result of increases in natural gas strip prices between the dates the swaps were entered into and December 31, 2016.

Risk management contracts were entered into during the second quarter of 2016 to limit downside pricing risk. The contract provided realized gains of $476,353 during that quarter. Without these hedges, Questfire would have had negative funds flow from operations in a quarter in which the Corporation's credit facility agreements were up for renewal. The contract terms brought forward higher future curve pricing during a period in which natural gas pricing was at multi-decade lows and when operating netbacks were very thin.

Following this, natural gas demand during the summer of 2016 was unexpectedly strong, with low prices spurring demand from electricity producers as natural gas was priced more favourably than coal. These hedges covered approximately 50 percent of Questfire's production during the period. The Corporation lost money on the hedges but the hedges helped Questfire survive an extremely challenging period in the upstream oil and gas industry.

During the second half of 2016, the terms of the Corporation's credit facility agreement prohibited it from entering into any risk management contracts. The facility's December 2016 extension allowed Questfire to resume a hedging program, but only until the facility's May 31, 2017 renewal. Subsequent to the end of 2016 the Corporation entered into the following hedges:

Period	Commodity	Type of contract	Notional quantity	Pricing point	Contract price
Apr. 1/17 - May 31/17	Natural Gas	Swap	2,500 GJ/d	AECO 7A	Cdn$2.600/GJ
Feb. 1/17 - May 31/17	Oil	Costless collar	100 bbls/d	WTI Nymex	US$48.00/bbl-US$54.80/bbl
Feb. 1/17 - May 31/17	Oil	Purchased put [1]	100 bbls/d	WTI Nymex	US$51.75/bbl
Feb. 1/17 - May 31/17	Oil	Swap	125 bbls/d	WTI Nymex	US$52.50/bbl

[1] Requires the Corporation to pay a monthly premium of $3.00 per bbl over the term for a total premium of $36,000.

General and Administrative (G&A) and Corporate Reorganization Expenses

	Three months ended December 31, 2016	2015	Year ended December 31, 2016	2015
	$	$	**$**	$
G&A	**1,042,233**	1,107,189	**4,353,413**	5,093,196
Corporate reorganization	**-**	-	**393,371**	-
Total	**1,042,233**	1,107,189	**4,746,784**	5,093,196
G&A expense per boe	**2.51**	2.38	**2.57**	2.86
Corporate reorganization expense per boe	**-**	-	**0.23**	-
Total expense per boe	**2.51**	2.38	**2.80**	2.86

G&A expenses were lower than in the comparative periods in 2015 predominantly due to the implementation in February 2016 of an across-the-board salary reduction of 20 percent, as well as staff reductions in March and April 2016. Salaries represent approximately 45 percent of G&A expenditures.

Reorganization expenses were incurred through services related to the ongoing review of strategic alternatives. These include fees for a financial advisor, legal consultations, and reservoir engineers.

Share-Based Compensation

	Three months ended December 31, 2016	2015	Year ended December 31, 2016	2015
	$	$	**$**	$
Share-based compensation	**76,738**	200,365	**487,535**	724,614
Per boe	**0.18**	0.43	**0.29**	0.41

The decrease in share-based compensation from the comparative periods in 2015 is largely a result of no new stock options being granted during the year ended December 31, 2016. Share-based compensation reversals for unvested stock option forfeitures associated with staffing reductions were largely offset by accelerated expensing of stock options voluntarily surrendered for no consideration. The individuals who voluntarily surrendered the 300,000 stock options were the same who received 200,000 stock options in November 2015, when other option-holders had their out-of-the-money options repriced to $1.00 per Class A share. Under IFRS, stock option cancellations initiated by an option holder are considered to have had the full option benefits provided to the option holder. Management believes this non-cash event provides benefits to shareholders, as it enables the Corporation to issue additional options to employees without depleting available financial resources or increasing potential share dilution for existing and prospective shareholders.

The Corporation did not grant any stock options to purchase Class A shares during the year ended December 31, 2016. There were 3,133,500 options outstanding at December 31, 2016 and 3,008,500 as of the date of this MD&A. The reduction in options outstanding from December 31, 2016 is due to expirations of vested options related to staffing reductions during the first four months of 2016. There were 2,385,722 options exercisable at December 31, 2016.

Exploration and Evaluation (E&E) Expenditures

	Three months ended December 31,		Year ended December 31,	
	2016	2015	**2016**	2015
	$	$	**$**	$
Cash E&E expense	**176,569**	300,939	**767,208**	880,497
Non-cash mineral rights expiries	**-**	338,731	**458,602**	338,731
E&E expense	**176,569**	639,670	**1,225,810**	1,219,228
Cash E&E expense per boe	**0.42**	0.65	**0.45**	0.49
Non-cash mineral rights expiries per boe	**-**	0.72	**0.27**	0.19
Per boe	**0.42**	1.37	**0.72**	0.68

The decrease in cash E&E expenditures from the comparative 2015 periods is due to lower employee salaries, effective February 2016.

Non-cash mineral rights expiries relate to mineral rights voluntarily relinquished by the Corporation as a result of low commodity prices.

Depletion and Depreciation (D&D)

	Three months ended December 31,		Year ended December 31,	
	2016	2015	**2016**	2015
	$	$	**$**	$
D&D	**2,572,887**	2,880,401	**10,426,977**	11,554,711
Per boe	**6.19**	6.19	**6.15**	6.49

The Corporation's D&D was largely unchanged from the comparative periods in 2015. Questfire continues to experience a low rate of depletion per boe, which it estimates is in the most advantageous decile of Canadian oil and natural gas producers, illustrating the value created from acquisitions and the Corporation's low finding and development costs per boe.

Property and Equipment Impairment (Reversal)

Impairment is recognized when the carrying value of an asset or CGU exceeds its recoverable amount, defined as the higher of its value in use or fair value less costs of disposal. Should there be indicators that the recoverable amount of an asset or CGU previously impaired has increased materially in value since recording the initial impairment, an impairment reversal may be recognized up to the value prior to impairment, less any subsequent associated D&D. For the year ended December 31, 2016 the Corporation recorded a property and equipment impairment reversal of $2,426,000 (year ended December 31, 2015 – $3,000,000 impairment) pertaining to the Open Lake CGU. As commodity price volatility remains above average, impairment charges or reversals can be expected in future periods.

Gain on Sale of Assets

	Three months ended December 31,		Year ended December 31,	
	2016	2015	**2016**	2015
	$	$	**$**	$
Gain on sale of assets	**3,132,905**	-	**3,566,744**	-
Per boe	**7.53**	-	**2.10**	-

The gain on sale of assets during the year ended December 31, 2016 pertains to the sale of all Questfire's royalty assets, as well as non-core assets in various cash-generating units (CGU), for total proceeds of $10,610,040. During the fourth quarter of 2016 the Corporation sold all of its royalty interests, as well as non-core assets in Willesden Green, part of the Open Lake CGU, and in the Westerose CGU for gross proceeds of $8,800,244. During the third quarter of 2016, non-core assets in the Westerose and Brazeau River CGUs were sold for proceeds of $307,387. During the second quarter of 2016 the Corporation also sold non-core assets in Wildmere, part of the East Central CGU, and in the Brazeau River CGU, for proceeds of $1,950,000. Transaction costs in the amount of $447,591 were incurred.

Finance Expense

	Three months ended December 31,		Year ended December 31,	
	2016	2015	**2016**	2015
	$	$	**$**	$
Interest on bank debt	**940,863**	515,546	**2,935,342**	1,718,095
Interest on long-term contract obligation	**490,776**	503,098	**1,981,084**	2,026,058
Financing costs	**114,302**	-	**536,322**	75,000
Cash finance expense	**1,545,941**	1,018,644	**5,452,748**	3,819,153
Recovery of decommissioning provision change in estimates	**(1,000,000)**	-	**(1,000,000)**	-
Accretion on decommissioning provisions	**503,360**	407,564	**1,762,662**	1,731,861
Accretion on Class B share liability	**77,856**	108,436	**417,543**	420,072
Non-cash finance expense	**(418,784)**	516,000	**1,180,205**	2,151,933
Total finance expense	**1,127,157**	1,534,644	**6,632,953**	5,971,086
Per boe	**2.71**	3.30	**3.91**	3.36

Interest on bank debt relates to interest and fees paid to Questfire's bankers to service the bank debt and bank overdraft. Interest on bank debt increased in the 2016 periods over the 2015 comparative periods primarily due to higher interest rate premiums resulting from lower cash flows associated with lower commodity prices. Interest rate premiums are based on the Corporation's trailing four-quarter EBITDA, adjusted for non-recurring items.

Interest on the long-term contract obligation relates to the facilities joint venture agreement entered into on March 26, 2014 with a third party. Questfire received $15.0 million, a portion of which was used to repurchase convertible debentures issued in 2013, in exchange for beneficial ownership of Questfire's natural gas processing facilities at Lookout Butte and Medicine Hat, Alberta. The Corporation pays an annual facility fee of $2,326,300, with a term of 17.5 years, after which beneficial ownership will revert to Questfire.

Financing costs relate to a combination of credit facility renewal fees, bank due diligence fees, and legal fees associated with credit facility renewals.

The recovery of decommissioning provision change in estimates during the year ended December 31, 2016 is a result of a reduction in the decommissioning provision component of P&E attributable to the Edmonton CGU, which has a $Nil fair value. As a result, changes in the credit-adjusted risk-free discount rate and estimates for the decommissioning provision related to these properties resulted in a recovery of $1,000,000 for the year ended December 31, 2016 (year ended December 31, 2015 – $Nil).

Class B share accretion decreased in 2016 from the comparative 2015 periods due to all remaining Class B shares being converted to Class A shares at the end of November 2016. As of the date of this report, there were no Class B shares outstanding.

Deferred Income Tax

Deferred income tax was an expense of $1,088,625 and a recovery of $2,609,811 in, respectively, the three months and year ended December 31, 2016, compared to recoveries of $351,156 and $3,049,379 in the respective comparative periods in 2015. The expense in the three months ended December 31, 2016 resulted from the gain on sale of assets as well as the P&E impairment reversal. The decrease in the recovery for the year ended December 31, 2016 from the comparative 2015 period resulted from changes to losses on which income tax is calculated, net of any effects from the gain on sale of assets.

Income (Loss)

The Corporation realized income of $2,752,322 ($0.14 per share basic and $0.12 diluted) and incurred a loss of $7,528,123 ($0.42 per share basic and diluted), respectively, for the three months and year ended December 31, 2016, compared to losses of $1,152,161 ($0.07 per share basic and diluted) and $10,386,781 ($0.60 per share basic and diluted) for the respective comparative periods in 2015. The income in the three months ended December 31, 2016 resulted from the gain on sale of assets and the impairment reversal. The current year's decreased loss resulted primarily from the gain on sale of assets and impairment reversal.

Selected Annual Information

Years ended December 31,	**2016**	2015	2014
	$	$	$
Oil and natural gas sales	**32,180,438**	40,717,011	71,619,004
Royalties	**(1,667,597)**	(2,945,794)	(9,744,194)
Net revenues	**30,512,841**	37,771,217	61,874,810
Funds flow from operations	**4,833,132**	11,543,473	23,113,274
Per share, basic	**0.27**	0.67	1.51
Per share, diluted	**0.21**	0.48	0.83
Income (loss)	**(7,528,123)**	(10,386,781)	24,795,298
Per share, basic	**(0.42)**	(0.60)	1.62
Per share, diluted	**(0.42)**	(0.60)	0.92
Total assets	**94,892,959**	115,610,438	133,863,233
Total non-current financial liabilities [1]	**13,760,534**	55,562,170	58,166,930

[1] Excludes decommissioning provisions and deferred tax liabilities.

Supplemental Information

The following tables summarize key financial and operating information for the periods indicated:

Funds Flow from Operations

	Three months ended December 31,		**Year ended December 31,**	
	2016	2015	**2016**	2015
	$	$	**$**	$
Income (loss)	**2,752,322**	(1,152,161)	**(7,528,123)**	(10,386,781)
Non-cash items:				
Unrealized loss on risk management	**492,007**	676,649	**2,957,743**	3,390,491
Share-based compensation	**76,738**	200,365	**487,535**	724,614
E&E	**-**	338,731	**458,602**	338,731
D&D	**2,572,887**	2,880,401	**10,426,977**	11,554,711
Impairment (reversal) of property and equipment	**(2,426,000)**	(1,500,000)	**(2,426,000)**	3,000,000
Deferred income tax expense (recovery)	**1,088,625**	(351,156)	**(2,609,811)**	(3,049,379)
Finance expense	**1,127,157**	1,534,644	**6,632,953**	5,971,086
Gain on sale of assets	**(3,132,905)**	-	**(3,566,744)**	-
Funds flow from operations	**2,550,831**	2,627,473	**4,833,132**	11,543,473

Netback Analysis

	Three months ended December 31,		Year ended December 31,	
	2016	2015	**2016**	2015
	$/boe	$/boe	**$/boe**	$/boe
Average sales price	**25.11**	20.20	**18.98**	22.88
Royalties	**(1.58)**	(1.03)	**(0.98)**	(1.66)
Production and operating expense	**(10.98)**	(11.26)	**(10.46)**	(11.79)
Transportation expense	**(1.27)**	(1.02)	**(1.09)**	(0.95)
Operating netback	**11.28**	6.89	**6.45**	8.48
G&A and corporate reorganization	**(2.51)**	(2.38)	**(2.80)**	(2.86)
E&E [(1)]	**(0.42)**	(0.65)	**(0.45)**	(0.49)
Realized gain (loss) on risk management	**(1.98)**	1.79	**(0.29)**	1.47
Bad debt expense	**(0.24)**	(0.01)	**(0.06)**	(0.11)
Funds flow netback	**6.13**	5.64	**2.85**	6.49
Finance expense	**(2.71)**	(3.30)	**(3.91)**	(3.36)
Gain on sale of assets	**7.53**	-	**2.10**	-
D&D	**(6.19)**	(6.19)	**(6.15)**	(6.49)
Share-based compensation	**(0.18)**	(0.43)	**(0.29)**	(0.41)
Unrealized loss on risk management	**(1.18)**	(1.45)	**(1.74)**	(1.90)
Impairment (reversal) of property and equipment	**5.83**	3.23	**1.43**	(1.69)
E&E mineral rights expiries	**-**	(0.72)	**(0.27)**	(0.19)
Deferred income tax (expense) recovery	**(2.61)**	0.75	**1.54**	1.71
Income (loss) per boe	**6.62**	(2.47)	**(4.44)**	(5.84)

(1) Excludes non-cash E&E expenditures associated with mineral rights expiries included below.

Selected Quarterly Information

Three months ended	**Dec. 31, 2016**	Sept. 30, 2016	June 30, 2016	March 31, 2016	Dec. 31, 2015	Sept. 30, 2015	June 30, 2015	March 31, 2015
Financial ($000s, except per share amounts and share numbers)								
Oil and natural gas sales	**10,446**	8,162	6,287	7,285	9,406	9,854	10,603	10,854
Funds flow from operations	**2,551**	1,899	361	23	2,627	2,628	3,236	3,052
Per share, basic *($)*	**0.13**	0.11	0.02	-	0.15	0.15	0.19	0.18
Per share, diluted *($)*	**0.11**	0.08	0.02	-	0.11	0.11	0.14	0.13
Income (loss)	**2,752**	(1,636)	(5,226)	(3,418)	(1,152)	(5,330)	(1,904)	(2,000)
Per share, basic *($)*	**0.14**	(0.09)	(0.30)	(0.20)	(0.07)	(0.31)	(0.11)	(0.12)
Per share, diluted *($)*	**0.12**	(0.09)	(0.30)	(0.20)	(0.07)	(0.31)	(0.11)	(0.12)
Capital expenditures	**231**	103	178	139	83	2,310	914	1,649
Total assets *(end of quarter)*	**94,893**	94,531	98,412	111,828	115,610	119,845	125,498	129,884
Working capital deficit *(end of quarter)*	**41,326**	54,529	54,926	11,077	9,653	7,544	4,166	4,103
Long-term contract obligation *(end of quarter)* [1]	**13,761**	13,893	13,965	14,062	14,156	14,246	14,334	14,418
Non-current bank debt *(end of quarter)*	**-**	-	-	41,839	41,406	39,062	40,590	40,774
Shareholders' equity *(end of quarter)*	**12,715**	4,382	5,928	10,987	14,251	15,203	20,361	22,089
Weighted-average basic shares outstanding *(000s)*	**19,233**	17,318	17,318	17,318	17,318	17,318	17,318	17,318
Weighted-average diluted shares outstanding *(000s)*	**23,473**	17,318	17,318	17,318	17,318	17,318	17,318	17,318
Operations								
Production								
Natural gas *(Mcf/d)*	**20,746**	20,636	19,872	22,785	23,245	20,684	20,690	22,341
NGL *(bbls/d)*	**695**	691	696	744	674	627	599	689
Crude oil *(bbls/d)*	**368**	414	413	501	512	522	605	790
Total *(boe/d)*	**4,521**	4,544	4,421	5,043	5,060	4,596	4,652	5,203
Average realized prices *($)*								
Natural gas *(per Mcf)*	**3.27**	2.43	1.51	1.97	2.57	2.95	2.73	2.87
NGL *(per bbl)*	**34.97**	28.19	28.23	25.40	31.74	31.72	40.87	33.25
Crude oil *(per bbl)*	**58.30**	46.10	46.84	32.35	41.02	50.13	58.72	42.51
Operating netback *(per boe)*	**11.28**	7.84	3.17	3.67	6.89	8.65	9.53	8.96
Funds flow netback *(per boe)*	**6.13**	4.54	0.90	0.05	5.64	6.22	7.65	6.52

[1] Long-term contract obligation excludes current portion, which is included in working capital deficit.

Inherent to the nature of the oil and gas industry, fluctuations in Questfire's quarterly oil and natural gas sales, funds flow from or used in operations, and income or loss are primarily caused by variations in production volumes, realized commodity prices and the related impact on royalties, realized and unrealized gains/losses on financial instruments, changes in per-unit expenses, and deferred income taxes. Please refer to the Financial and Operating Results section above for an explanation of changes.

Capital Expenditures

	Three months ended December 31,		Year ended December 31,	
	2016	2015	**2016**	2015
	$	$	**$**	$
Land	**28,073**	14,127	**104,929**	69,307
Geological and geophysical	**-**	9,650	**12,150**	32,452
Drilling and completions	**1,218**	26,986	**29,881**	2,845,595
Production equipment and facilities	**148,137**	13,733	**348,670**	1,532,466
Well workovers and recompletions	**53,430**	18,247	**154,859**	472,911
Office equipment	**-**	-	**-**	2,317
	230,858	82,743	**650,489**	4,955,048

At December 31, 2016, the Corporation had E&E assets of $916,516 (December 31, 2015 – $1,340,456). This included 93,132 net acres of undeveloped land.

At December 31, 2016, the Corporation had gross property and equipment of $129,460,877. This included developed land and costs associated with the wells the Corporation has drilled and acquired to date. As well, it included $252,670 incurred since inception to purchase computer hardware and software, associated office furniture and office improvements for use by Questfire employees and consultants to evaluate oil and natural gas leads.

During 2016, no drilling activities were undertaken. As a result of marginal funds flow from operations, capital expenditures were minimized, with only maintenance capital taking place, in order to conserve cash.

Share Capital and Option Activity

As at the date hereof, the Corporation had 22,822,401 Class A shares, Nil Class B shares, and 3,008,500 stock options outstanding. Each Class B share was converted into Class A shares at the end of November 2016. Each Class B share was converted into 10 Class A shares in accordance with the conversion requirements. The number of Class A shares issued upon conversion of one Class B share was calculated by dividing $10 by the greater of $1 and the 30-day weighted-average market price of the Class A shares.

Liquidity and Capital Resources

At December 31, 2016, the Corporation had a working capital deficit of $38,368,058 (December 31, 2015 – $4,566,543), excluding the non-cash-settled convertible Class B shares and risk management contract liabilities. The increase from December 31, 2015 is due to the bank debt being included in the working capital deficit as at December 31, 2016. If bank debt were excluded, the working capital deficit at December 31, 2016 would decrease to $4,853,308. Funds flow from operations for the three months and year ended December 31, 2016 were $2,550,831 and $4,833,132, respectively, which were used to pay interest on debt, other financing costs, and decrease the bank debt. Funds generated from operations during 2017 are anticipated to be used for debt reduction as well as limited capital expenditures and decommissioning work.

The sustained decline in commodity prices caused the Corporation to defer the majority of its capital expenditure program for operated properties in order to maintain financial flexibility and remain in compliance with credit facility covenants. The Corporation will be in a position to resume its planned capital program as soon as commodity prices improve.

The Corporation's credit facility matures on May 31, 2017, requiring it to be presented as a current liability. The Corporation is in discussions with the lenders to extend the loan. Should this occur, the Corporation expects that it will have sufficient cash on hand to meet immediate obligations by actively monitoring its credit facilities through co-ordinating payment and revenue cycles each month and through continuing the cost reduction measures being undertaken since mid-2014. Should the lender decline to extend the loan or reduce the amount available, the Corporation would need to seek alternative sources of debt or equity financing, or sell assets.

The credit facility includes a number of covenants approved by the syndicate of lenders ("the Syndicate"). The operational covenant requires Questfire to maintain production volumes of at least 80 percent of those forecast by the Corporation and approved by the Syndicate. This covenant has been met.

The first financial covenant requires Questfire to have, at the end of each quarter, maximum consolidated net debt of $47.5 million, which for purposes of the covenant is calculated as long-term bank debt and working capital, excluding convertible Class B shares, and risk management contracts. The consolidated net debt, including letters of credit, at December 31, 2016 was $38.6 million. The second financial covenant requires Questfire to generate minimum monthly EBITDA, as defined by the agreement, of 80 percent of that forecast by the Corporation and approved by the Syndicate. This covenant was met through December 2016. The third financial covenant requires Questfire to have a cumulative negative monthly cash flow variance of no more than $0.5 million from the amount forecast by the Corporation in August 2016 and approved by the Syndicate. This covenant was met through December 2016. The fourth financial covenant requires Questfire to have risk management contracts by January 31, 2017 for between 40 percent and 60 percent of its proved developed producing production through the end of May 2017. This covenant was met.

The Corporation is also subject to several corporate covenants. The first corporate covenant requires Questfire to dispose of several specific minor oil and natural gas properties for no less than $0.425 million before January 31, 2017. This covenant was breached; a waiver, however, was issued by the Syndicate and one of the properties was sold for $0.3 million. The second corporate covenant required Questfire to enter into a term sheet in the amount of no less than $67 million by January 31, 2017 in order to pay out the Syndicate by February 28, 2017. If either of these deadlines is not met, a minimum of $5 million must be raised by March 15, 2017, of which a minimum of $2.5 million must be used to drill a minimum of two wells and a minimum of $2.5 million must be used to repay the supplemental facility. Such funds raised must come from sources other than asset dispositions, cash flow or the credit facility. This covenant was breached, and the deadlines were extended from February 28, 2017 to March 31, 2017 and from March 15, 2017 to the earlier of April 30, 2017 and the date which is 30 days from the date the Syndicate determines that a corporate merger will not be entered into, respectively. The third corporate covenant required Questfire to sign a letter of intent for a corporate merger with a specific entity prior to December 23, 2016. This covenant was met.

For 2017, the Corporation forecasts incurring maintenance capital expenditures of $0.6 million and decommissioning costs of $1.2 million.

The size of the Corporation's capital expenditures will be affected by the total funding available through varying combinations of the funds generated from operations, additional debt or equity as market conditions may allow, and potential asset sales if the Corporation so chooses. Management believes that if a farm-out or asset sale were to be conducted, funds received would be sufficient to eliminate the current working capital deficit, which was $4,853,308 at December 31, 2016 excluding the risk management contract liability and bank debt.

The Corporation generally relies on operating cash flows, equity issuances and its credit facility to fund its capital requirements and provide liquidity. From time to time, the Corporation may access capital markets to meet additional financing needs and maintain flexibility in funding its capital programs. Future liquidity depends primarily on funds generated from operations, drawing on existing credit facilities and accessing debt and equity markets.

Going Concern

Although the Corporation's forecast funds flow from operations, after subtracting cash finance expense and anticipated decommissioning costs and property and equipment expenditures, are positive for 2017 under commodity strip pricing forecasts, these levels will not furnish funds flow and EBITDA sufficient to meet Syndicate covenants. In addition, the Corporation remains close to its borrowing limits and has negative working capital. The determination of the borrowing base, which is to take place before May 31, 2017, remains uncertain. As such, the Corporation has included a going-concern uncertainty note in its financial statements for the year ended December 31, 2016. Management's attention remains focused on managing the Corporation's resources through this difficult commodity price environment.

Off-Balance-Sheet Arrangements

The Corporation does not have any special-purpose entities nor is it a party to any arrangements that would be excluded from the balance sheet.

Environmental Initiatives Affecting Questfire

In October 2016, the Government of Canada announced a national carbon pricing regime in response to the Paris Agreement ratified by Canada earlier that month. Under the Carbon Strategy, a benchmark carbon pricing program will be applied, pricing carbon emissions at a minimum of $10 per tonne in 2018, rising by $10 per tonne each year to $50 per tonne by 2022. The Carbon Strategy also proposes a federal backstop in the event that jurisdictions fail to meet the benchmark. The Government of Alberta established a carbon pricing system referenced in the federal announcement; therefore, in the short term, the national price on carbon will likely have little additional impact to Questfire beyond that imposed by the Government of Alberta.

Additional details of the national carbon pricing regime are expected to be finalized in the coming months, and further legislation and regulation are expected. At this time, Questfire is unable to predict the impact of the Paris Agreement and the national carbon pricing regime on its operations. It is possible that mandatory emissions reductions that might be included in this regime would have a material adverse effect on Questfire's financial condition, results of operations and cash flow.

Commitments

As part of its normal operations, Questfire has committed to paying certain amounts over the next five years and thereafter as follows:

	2017	2018	2019	2020	2021	Thereafter
	$	$	$	$	$	$
Office lease	767,087	767,087	447,467	-	-	-

Questfire's commitments related to its risk management program are disclosed in "Risk Management" and its commitments related to its long-term contract obligation are disclosed in "Liquidity and Capital Resources".

Related-Party Transactions

The Corporation retains a law firm to provide legal services in which one of the Corporation's directors, Roger MacLeod, was a partner until his retirement on December 31, 2015. Legal fees of $69,499 and $174,847 were incurred by Questfire to the law firm in the respective three months and year ended December 31, 2016 (three months and year ended December 31, 2015 – $5,064 and $41,054, respectively), of which $5,742 and $65,323, respectively (three months and year ended December 31, 2015 – $4,776 and $40,776, respectively), was related to general and administrative expenses, $17,605 and $31,644, respectively (three months and year ended December 31, 2015 – $287 for both periods), was related to finance expense, $2,123 and $33,851, respectively (three months and year ended December 31, 2015 – $Nil for both periods), was related to corporate reorganization, and $44,029 for both periods (three months and year ended December 31, 2015 – $Nil for both periods) was related to transaction costs which are included in the calculation of gain on sale of assets. At December 31, 2016, $Nil (December 31, 2015 – $12,988) of these amounts was included in accounts payable and accrued liabilities and was due under normal credit terms.

Hedging

The Corporation historically practiced an active hedging program, with the objective to provide a measure of downside protection for its oil and natural gas sales and cash flow from operations, while maximizing exposure to potential commodity pricing upside. At December 31, 2016, the Corporation's hedges covered approximately 23 percent of forecast production for 2017 in the form of swaps (see "Risk Management" above).

Critical Accounting Judgments, Estimates and Policies

The Corporation's critical accounting judgements, estimates and policies are described in notes 2 and 3 to the December 31, 2016 annual financial statements. Certain accounting policies are identified as critical because they require management to make judgments and estimates based on conditions and assumptions that are inherently uncertain, and because the estimates are of material magnitude to revenue, expenses, funds flow from operations, income or loss and/or other important financial results. These accounting policies could result in materially different results should the underlying conditions change or the assumptions prove incorrect.

Critical accounting estimates are those requiring management to make particularly subjective or complex judgments about inherently uncertain matters. Estimates and underlying assumptions are reviewed on an ongoing basis and any revisions to accounting estimates are recognized in the same period.

Management's assumptions are based on factors that, in management's opinion, are relevant and appropriate, and may change over time as operating conditions change.

New accounting standards

There were no new or amended accounting standards or interpretations adopted during the year ended December 31, 2016 that had a material effect on Questfire.

Accounting standards issued but not yet adopted

A number of new accounting standards, amendments to accounting standards and interpretations are effective for annual periods beginning on or after January 1, 2017 and have not been applied in preparing the financial statements for the year ended December 31, 2016. The standards applicable to the Corporation are as follows and will be adopted on their respective effective dates:

(i) In July 2014, the IASB issued IFRS 9, *Financial Instruments*, to replace IAS 39, *Financial Instruments: Recognition and Measurement*. IFRS 9 replaces the guidance in IAS 39 that relates to the classification and measurement of financial instruments. It retains but simplifies the mixed measurement model and establishes three primary measurement categories for financial assets: amortized cost, fair value through other comprehensive income and fair value through profit and loss. The basis of classification depends on the entity's business model and the contractual cash flow characteristics of the financial asset. Investments in equity instruments must be measured at fair value through profit or loss with the irrevocable option at inception to present changes in fair value in other comprehensive income not recycling. IFRS 9 includes a new model for expected credit losses, replacing the incurred loss impairment model used in IAS 39. For financial liabilities there were no changes to classification and measurement except for the recognition of changes in own credit risk in other comprehensive income, for liabilities designated at fair value through profit or loss. IFRS 9 relaxes the requirements for hedge effectiveness by replacing the bright-line hedge effectiveness tests. It requires an economic relationship between the hedged item and hedging instrument and for the "hedged ratio" to be the same as the one management actually uses for risk management purposes. Contemporaneous documentation is still required but is different from that currently prepared under IAS 39. IFRS 9 is effective for years beginning on or after January 1, 2018, with early adoption permitted if the standard is adopted in its entirety at the beginning of a fiscal period. The Corporation is evaluating the impact on its financial statements of adopting IFRS 9.

(ii) In May 2014, the IASB published IFRS 15, *Revenue from Contracts with Customers,* replacing IAS 11, *Construction Contracts*, IAS 18, *Revenue*, and several revenue-related interpretations. IFRS 15 establishes a single revenue recognition framework that applies to contracts with customers. The standard requires an entity to recognize revenue to reflect the transfer of goods and services for the amount it expects to receive, when control is transferred to the purchaser. Disclosure requirements have also been expanded.

On September 11, 2015, the IASB published an amendment to IFRS 15, deferring the effective date of the standard by one year to years beginning on or after January 1, 2018, with early adoption permitted. The standard may be applied retrospectively or using a modified retrospective approach. The Corporation is evaluating the impact on its financial statement of adopting IFRS 15.

(iii) On January 13, 2016, the IASB issued IFRS 16, *Leases*, which requires entities to recognize lease assets and lease obligations on the balance sheet. For lessees, IFRS 16 removes the classification of leases as either operating leases or finance leases, effectively treating all leases as finance leases. Certain short-term leases (less than 12 months) and leases of low-value assets are exempt from the requirements, and may continue to be treated as operating leases. IFRS 16 is effective for years beginning on or after January 1, 2019, with early adoption permitted if IFRS 15 has been adopted. The standard may be applied retrospectively or using a modified retrospective approach. The Corporation is evaluating the impact on its financial statements of adopting IFRS 16.

(iv) In January 2016, the IASB issued amendments to IAS 7, *Statement of Cash Flows*, as part of its disclosure initiative. The amendments require an entity to disclose changes in liabilities arising from financing activities. IAS 7 is effective for years beginning on or after January 1, 2017 with earlier adoption permitted. The Corporation is applying the amendments to IAS 7 on January 1, 2017, which is expected to have an immaterial impact on its financial statements.

There are no other not-yet-effective IFRS or IFRIC interpretations that would be expected to have a material impact on the Corporation.

Funds flow from operations

Questfire uses "funds flow from operations" (cash from operating activities before changes in non-cash working capital and decommissioning costs incurred), a measure that is not defined under IFRS. Funds flow from operations should not be considered an alternative to, or more meaningful than, cash from operating activities, income (loss) or other measures determined in accordance with IFRS as an indicator of the Corporation's performance. Management uses funds flow from operations to analyze operating performance and leverage and believes it is a useful supplemental measure as it provides an indication of the funds generated by Questfire's principal business activities prior to consideration of changes in working capital and remediation expenditures.

Non-GAAP measures

This MD&A includes references to financial measures commonly used in the oil and natural gas industry. The terms "operating netback" (oil and natural gas sales less royalties and production, operating and transportation expenses, all expressed on a per-unit-of-production basis) and "funds flow netback" (operating netback less G&A and transaction expenses, E&E expenditures and realized gain or loss on risk management) are not defined under IFRS, which have been incorporated into Canadian GAAP, as set out in Part 1 of the Chartered Professional Accountants Canada Handbook – Accounting, are not separately defined under GAAP, and may not be comparable with similar measures presented by other companies. Operating netback is a per-unit-of-production measure that may be used to assess the Corporation's performance and efficiency.

Basis of Barrel of Oil Equivalent

Petroleum and natural gas reserves and production volumes are stated as a "barrel of oil equivalent" (boe), derived by converting natural gas to oil equivalency in the ratio of 6,000 cubic feet of gas to one barrel of oil. Boe may be misleading, particularly if used in isolation. A boe conversion ratio of 6,000 cubic feet of gas to one barrel of oil is based on energy equivalency, which is primarily applicable at the burner tip, and does not represent a value equivalency at the wellhead. Readers are cautioned that boe figures may be misleading, particularly if used in isolation.

Forward-Looking Statements

This document contains certain forward-looking statements. Forward-looking statements are subject to known and unknown risks, uncertainties and other factors that could influence actual results or events and cause them to differ materially from those stated, anticipated or implied. Such forward-looking statements necessarily involve risks including, without limitation, those associated with oil and natural gas exploration, property development, production, marketing and transportation, such as dry holes and non-commercial wells, facility and pipeline damage, loss of markets, volatility of commodity prices, currency fluctuations, imprecision of reserve estimates, production declines, health, safety and environmental risks, competition from other producers and the ability to access sufficient capital from internal and external sources. Forward-looking information typically includes statements with words such as “anticipate”, “believe”, “expect”, “plan”, “intend”, “estimate”, “propose”, “project”, or similar words suggesting future outcomes. The Corporation cautions readers and prospective investors in the Corporation’s securities not to place undue reliance on forward-looking information as, by its nature, it is 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 Corporation.

Forward-looking information typically involves substantial known and unknown risks and uncertainties, certain of which are beyond the Corporation’s control. Such risks and uncertainties include, without limitation: financial risk of marketing reserves at an acceptable price given market conditions; volatility in market prices for oil and natural gas; delays in business operations; pipeline restrictions; blowouts; the risk of carrying out operations with minimal environmental impact; industry conditions including changes in laws and regulations including the adoption of new environmental laws and regulations and changes in how they are interpreted and enforced; uncertainties associated with estimating oil and natural gas reserves; risks and uncertainties related to oil and gas interests and operations on aboriginal lands; economic risk of finding and producing reserves at a reasonable cost; uncertainties associated with partner plans and approvals; operational matters related to non-operated properties; increased competition for, among other things, capital, acquisitions of reserves and undeveloped lands; competition for and availability of qualified personnel or management; incorrect assessments of the value of acquisitions and exploration and development programs; unexpected geological, technical, drilling, construction, processing and transportation problems; availability of insurance; fluctuations in foreign exchange and interest rates; stock market volatility; general economic, market and business conditions; uncertainties associated with regulatory approvals; uncertainty of government policy changes; uncertainties associated with credit facilities and counterparty credit risk; changes in income tax laws, Crown royalty rates and incentive programs relating to the oil and gas industry; and other factors, many of which are outside the Corporation’s control. The Corporation’s actual results, performance or achievements could, therefore, differ materially from those expressed in, or implied by, these forward-looking estimates and whether or not any such actual results, performance or achievements transpire or occur, there can be no certainty as to what benefits or detriments the Corporation will derive therefrom.

The forward-looking information included herein is expressly qualified in its entirety by this cautionary statement. It is made as of the date hereof and the Corporation assumes no obligation to update or revise any forward-looking information to reflect new events or circumstances, except as required by law.

Abbreviations

The following summarizes the abbreviations used in this document:

Crude Oil and Natural Gas Liquids

bbl	barrel
Mbbl	thousand barrels
bbls/d	barrels per day
boe	barrel of oil equivalent
Mboe	thousand barrels of oil equivalent
boe/d	barrel of oil equivalent per day
NGL	natural gas liquids

Natural Gas

Mcf	thousand cubic feet
MMcf	million cubic feet
Mcf/d	thousand cubic feet per day
GJ	Gigajoule; 1 Mcf of natural gas is about 1.05 GJ
MMBtu	million British thermal units; 1 GJ is about 0.95 MMBtu

Other

AECO	the AECO Hub, a natural gas storage facility located in Suffield and Countess, Alberta
$000s	thousands of dollars
IFRS	International Financial Reporting Standards
IAS	International Accounting Standard

Corporate Information

BOARD OF DIRECTORS

RICHARD DAHL (1)(2)(3)
President & CEO
Questfire Energy Corp.
Calgary, Alberta

NEIL DELL (1)(3)(4)
Independent Businessman
Calgary, Alberta

ROGER MACLEOD (1)(2)(4)
Independent Businessman
Calgary, Alberta

JOHN RAMESCU (3)(4)
Vice President, Land
Questfire Energy Corp.
Calgary, Alberta

Notes:
(1) Audit Committee
(2) Corporate Governance Committee
(3) Reserves Committee
(4) Compensation Committee

OFFICERS

RICHARD DAHL
President & Chief Executive Officer

DARREN KISSER
Vice President, Engineering and Operations

FRED LAUDEL
Vice President, Exploration

JOHN RAMESCU
Vice President, Land

BRUCE SHEPARD
Vice President, Exploitation

RONALD WILLIAMS
Vice President, Finance & Chief Financial Officer

GRAHAM NORRIS
Corporate Secretary

HEAD OFFICE
Suite 1100, 350 – 7th Avenue S.W.
Calgary, Alberta
T2P 3N9

Telephone: 403-263-6688
Facsimile: 403-263-6683

AUDITORS
Collins Barrow Calgary LLP
Calgary, Alberta

BANKERS
Alberta Treasury Branches
TD Canada Trust

EVALUATION ENGINEERS
GLJ Petroleum Consultants Ltd.
Calgary, Alberta

LEGAL COUNSEL
DLA Piper (Canada) LLP
Calgary, Alberta

TRANSFER AGENT
Computershare Limited
Calgary, Alberta

STOCK EXCHANGE LISTING
TSX Venture Exchange
Symbol: Q.A