Questfire Energy Corp. – Financial and Operating Highlights

	Three months ended December 31, 2015	2014	Year ended December 31, 2015	2014
Financial				
Oil and natural gas sales	**$ 9,405,900**	$ 15,918,460	**$ 40,717,011**	$ 71,619,004
Funds flow from operations	**2,627,473**	5,210,979	**11,543,473**	23,113,274
Per share, basic	**0.15**	0.30	**0.67**	1.51
Per share, diluted	**0.11**	0.24	**0.48**	0.83
Income (loss)	**(1,152,161)**	1,600,035	**(10,386,781)**	24,795,298
Per share, basic	**(0.07)**	0.09	**(0.60)**	1.62
Per share, diluted	**(0.07)**	0.08	**(0.60)**	0.92
Capital expenditures	**82,743**	2,863,699	**4,955,048**	19,206,548
Property dispositions	**$ -**	$ -	**-**	3,792,346
Working capital deficit *(end of year)* (1)			**9,653,400**	4,787,471
Long-term contract obligation *(end of year)* (2)			**14,155,697**	14,500,145
Long-term bank debt *(end of year)*			**41,406,473**	39,000,000
Shareholders' equity *(end of year)*			**$ 14,251,344**	$ 23,913,511
Shares outstanding *(end of year)*				
Class A			**17,318,001**	17,318,001
Class B			**550,440**	550,440
Options outstanding *(end of year)*			**3,566,000**	2,676,000
Weighted-average basic shares outstanding	**17,318,001**	17,318,001	**17,318,001**	15,267,001
Weighted-average diluted shares outstanding	**17,318,001**	21,549,892	**17,318,001**	28,452,243
Class A share trading price				
High	**$ 1.44**	$ 2.51	**$ 1.95**	$ 2.75
Low	**0.30**	1.70	**0.30**	0.95
Close	**$ 0.59**	$ 1.76	**$ 0.59**	$ 1.76
Operations (3)				
Production				
Natural gas *(Mcf/d)*	**23,245**	24,868	**21,741**	23,585
Natural gas liquids (NGL) *(bbls/d)*	**674**	712	**647**	674
Crude oil *(bbls/d)*	**512**	644	**606**	498
Total *(boe/d)*	**5,060**	5,501	**4,877**	5,103
Benchmark prices				
Natural gas				
AECO *(Cdn$/GJ)*	**$ 2.34**	$ 3.42	**$ 2.55**	$ 4.28
Crude oil				
WTI *(US$/bbl)*	**42.18**	73.15	**48.80**	93.00
Canadian Light *(Cdn$/bbl)*	**52.55**	75.11	**57.45**	94.18
Average realized prices (4)				
Natural gas *(per Mcf)*	**2.57**	3.74	**2.78**	4.65
NGL *(per bbl)*	**31.74**	51.38	**34.24**	65.52
Crude oil *(per bbl)*	**41.02**	67.23	**47.89**	85.06
Operating netback *(per boe)* (5)	**6.89**	13.78	**8.48**	17.63
Funds flow netback *(per boe)*	**$ 5.64**	$ 10.30	**$ 6.49**	$ 12.41

(1) Working capital deficit includes risk management contract assets and convertible Class B share liabilities of $Nil and $5,086,857, respectively (December 31, 2014 –$2,366,210 and $Nil, respectively). Excluding this, the working capital deficit would be $4,566,543 (December 31, 2014 – $7,153,681).

(2) Long-term contract obligation excludes current portion of $344,448 (December 31, 2014 – $300,242), which is included in working capital deficit.

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

(4) Before hedging.

(5) See "Non-GAAP measures".

2015 Corporate Highlights

- Achieved average production of 4,877 boe per day for the year, 74 percent natural gas. Production was down by approximately 4 percent from 2014 due to an estimated average of 344 boe per day of production restrictions on the Nova Gas Transmission Ltd. (NGTL) system throughout 2015.
- Achieved sales of $40.7 million and funds flow from operations of $11.5 million ($0.67 per basic share).
- Exercised capital spending discipline with total capital expenditures of $5.0 million, well within funds flow of $11.5 million.
- Drilled and completed the Corporation's first horizontal multi-stage fractured Falher gas well in the Morningside area of central Alberta.
- Incurred full-year operating costs of $11.79 per boe, achieving a 19.5 percent reduction from 2014 operating costs of $14.64 per boe.
- General and Administrative (G&A) costs were $5.1 million or $2.86 per boe, a reduction of 15 percent from 2014 G&A costs of $6.0 million or $3.23 per boe.
- At year-end, corporate working interest reserves were 15.15 million boe proved developed producing (PDP), 19.86 million boe total proved (TP) and 31.45 million boe proved plus probable (2P). Based on annualized fourth quarter 2015 average production of 5,060 boe per day, the Corporation's reserve life index (RLI) at year-end 2015 was 17.0 years for 2P reserves, 10.8 years for TP reserves and 8.2 years for PDP reserves.
- Incurred all-in finding and development (F&D) costs of $4.90 per boe for PDP, $3.78 per boe for TP and $10.85 per boe for 2P reserve additions, including all future development capital (FDC) and technical revisions. Based on the 2015 operating netback of $8.48 per boe, Questfire's recycle ratios are 1.73 for PDP, 2.24 for TP and 0.78 for 2P reserve additions.

President's Message

Two-thousand fifteen was an extremely challenging year for the oil and gas industry, with the term "lower for longer" joining the popular lexicon to describe what appears to be happening with commodity prices. The hoped-for improvement of oil and natural gas prices did not materialize in 2015 for a number of reasons, including a much warmer than average winter across North America. Natural gas prices plummeted to near 20-year lows and oil prices dropped into the low US$30's per bbl WTI range by the end of 2015. Forward hedging options became limited in 2015 as the forward strip prices declined quickly and sharply for both natural gas and oil.

Questfire, accordingly, adopted cautious positioning in 2015. We concentrated our efforts on reducing all costs, minimizing capital spending and maintaining production, taking full advantage of our very low-decline production base. Operating costs and G&A costs were reduced by a significant 20 percent and 15 percent, respectively, from 2014 levels and continue to decline into 2016. In February of this year we implemented an across-the-board salary reduction of 20 percent which, given that approximately half of our G&A costs are staff salaries, facilitates a further 10 percent reduction in our go-forward G&A costs.

Capital spending of $5.0 million included mandatory and maintenance capital such as the replacement and repair of flood-damaged pipelines at Lookout Butte for approximately $1.0 million and the drilling of one net horizontal multi-stage fractured Falher gas well in the Morningside area of central Alberta for $2.5 million. Without the NGTL production restrictions of approximately 344 boe per day our production would have averaged approximately 5,200 boe per day for the year, which would have been up slightly year-over-year. Considering this included drilling only one well and compared to the 5,103 boe per day average production for 2014, the low-decline nature of Questfire's production base is clearly illustrated.

Although our capital spending in 2015 was limited, the Questfire team focused their efforts on creating value. Drilling comprised one, 100 percent working interest, high-impact horizontal gas well located at 1-11-42-28W4M in the Morningside field. The 1-11 well came on-production in mid-October 2015 at approximately 300 boe per day of liquids-rich natural gas and has proved up a further 9 gross (7.9 net) horizontal drilling locations on the play, contributing a significant portion of our booked reserve additions for 2015. A second significant project involved reservoir limits testing and a reservoir simulation study conducted on the Elkton G pool at Carstairs. This has established the potential for a gas cycling light oil enhanced oil recovery (EOR) project in this 70 percent working interest, operated pool. At year-end approximately 1.3 MMboe of net incremental probable oil reserves were booked by GLJ Petroleum Consultants Ltd. for this project. Also of significant value is the Corporation's drilling inventory, which includes over 380 net locations as of year-end 2015, the majority of which are high working interest and operated.

Questfire continued to add reserves efficiently in 2015 with F&D costs, shown in the highlights above, that will likely be in the top-performing decile for the industry. It is important to note that since Questfire's inception in 2010 only $10.7 million of equity has been raised by the Corporation. In five years the Questfire team managed to turn this limited amount of capital into a 5,000+ boe per day, low-decline production base with over 380 net drilling prospects, which has generated over $65 million in field operating income (oil and natural gas sales less royalties, production and operating, and transportation expenses) since 2013. At year-end 2015 our all-in finding, development and acquisition (FD&A) costs since inception, including all FDC, have been $5.97 per boe for PDP reserves, $5.83 per boe for TP reserves and $5.63 per boe for 2P reserves. These metrics place Questfire in the most efficient decile of western Canada's oil and gas industry and again demonstrate that the Questfire team are able value creators.

In December, due to lower commodity price forecasts, our bank lines were reduced from $55 million to $45 million. While our year-end debt of $41.4 million is within this new limit, it does not afford Questfire the flexibility to spend capital incremental to its cash flow. At year-end the Questfire management team recognized the potential for "lower for longer" commodity prices which are largely causing the significant headwinds facing the Canadian oil and gas industry. These headwinds also include a lack of markets for our production due to competition from the United States, reduced availability of debt financing from Canadian banks, investor uncertainty, and reduced equity investment available. The latter issues are largely due to adverse provincial and federal government policies such as the Alberta royalty review, new carbon taxes, grandiose yet vague climate change policies, increases in general taxation, increasing delays in project approvals, lengthened timelines for LNG and oil export projects, and a general lack of support for the industry.

Fortunately, in spite of these many headwinds, Questfire continues to have options. Our base production decline is low, our cost structure has been reduced significantly and will continue to decline, our drilling inventory of over 380 net locations is an all-time high, with the majority being high-working-interest and operated, our year-end F&D costs are expected to show top-decile industry performance and our experienced management team is committed with a high ownership. We have identified a number of enhanced oil opportunities and we have a significant royalty income stream and mid-stream type assets such as the third-party fee-generating Crystal Lake pipeline system. Because of these many options, the management team and Board of Directors agreed that proactively engaging an experienced financial advisor would be the best and quickest course of action to evaluate all options with the goal of maximizing shareholder value. Accordingly, subsequent to year-end, Macquarie Capital Markets Canada Ltd. was engaged as a financial advisor and a Strategic Alternatives process was announced in early March. This process was launched proactively by Questfire to efficiently evaluate the many available options. This ongoing process is under the control of Questfire and may include but is not limited to a strategic financing, merger or other business combination, sale of the Corporation or a portion of the Corporation's assets, or any combination thereof.

As with all of our activities throughout 2015 and, indeed, with everything we have done since Questfire's founding, the goal of this process is to maximize value. Going forward the Questfire team will continue to work on reducing all costs, spend within funds flow and pursue all options to create value for the Corporation's shareholders.

On behalf of the Board of Directors,

(Signed) "Richard Dahl"

Richard H. Dahl
President and Chief Executive Officer
April 26, 2016

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 26, 2016 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, 2015 and 2014. 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 the section 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 symbols Q.A and Q.B.

Financial and Operating Results

Production

	Three months ended December 31,		Year ended December 31,	
	2015	2014	**2015**	2014
Daily average volume				
Natural gas *(Mcf/d)*	**23,245**	24,868	**21,741**	23,585
NGL *(bbls/d)*	**674**	712	**647**	674
Crude oil *(bbls/d)*	**512**	644	**606**	498
Total sales *(boe/d)*	**5,060**	5,501	**4,877**	5,103
Total sales *(boe)*	**465,534**	506,108	**1,779,933**	1,862,620
Production weighting				
Natural gas	**77%**	75%	**74%**	77%
NGL	**13%**	13%	**13%**	13%
Crude oil	**10%**	12%	**13%**	10%
	100%	100%	**100%**	100%

Production decreased during the 2015 periods from the 2014 comparative periods largely due to third-party natural gas gathering system interruptions for maintenance. Production declines during 2015 were partially offset by production added through drilling activity during the second half of 2014 as well as the Morningside well drilled in the third quarter of 2015. Crude oil production increased for 2015 over 2014 as the 2014 drilling programme predominantly targeted crude oil production. The Corporation continues to experience a low production decline profile, with an overall decline rate of 15 percent.

Sales

	Three months ended December 31,		Year ended December 31,	
	2015	2014	**2015**	2014
	$	$	**$**	$
Natural gas	**5,505,749**	8,567,648	**22,037,826**	40,031,904
NGL	**1,968,139**	3,370,241	**8,085,658**	16,121,411
Crude oil	**1,932,012**	3,980,571	**10,593,527**	15,465,689
Total	**9,405,900**	15,918,460	**40,717,011**	71,619,004
Average realized prices before hedging				
Natural gas *($/Mcf)*	**2.57**	3.74	**2.78**	4.65
NGL *($/bbl)*	**31.74**	51.38	**34.24**	65.52
Crude oil *($/bbl)*	**41.02**	67.23	**47.89**	85.06
Combined average *($/boe)*	**20.20**	31.45	**22.88**	38.45

The Corporation's sales were lower for all major products in the three months and year ended December 31, 2015 than in the comparative 2014 periods due to significant declines in reference pricing.

Natural gas prices realized were lower in both periods of 2015 than in the comparative 2014 periods due to an abnormally cold winter in 2013-2014, leading to large draws of natural gas from storage and comparatively higher pricing. There was significant injection into underground storage during 2015, particularly as a result of incremental production from the Marcellus shale in the Northeastern United States, influencing demand and pricing in the Canadian market.

The Corporation, like almost all of the upstream oil and natural gas sector in Western Canada, experienced lower prices for NGL products than in the prior year's comparative periods. Propane pricing was negative for much of the second and third quarters of 2015, partially as a result of the Cochin pipeline reversal, which previously shipped propane out of Western Canada and now ships condensate into Alberta, stranding some propane in the province, as well as decreased demand in the United States resulting from increased liquids-rich natural gas production.

Crude oil pricing remained depressed in comparison to the 2014 periods as a result of a supply-demand imbalance, as member states of the Organization of Petroleum Exporting Countries (OPEC) maintained their production levels. The OPEC decision signals a desire to protect market share as opposed to supporting prices. Lower prices have resulted in significant reductions in 2015 capital spending in the energy industry, with clear signs of reduced activity, including a steep decline in the active drilling rig count in the United States, which fell to multi-decade lows subsequent to year-end, and very low rig utilization rates in Canada.

During the third quarter of 2015 there was initial evidence of declining North American production volumes, including reduced shale gas production in the United Sates, which had experienced virtually uninterrupted growth for over a decade. This general trend is anticipated to continue until oil and natural gas prices recover to levels that generate positive full-cycle returns. In the meantime, low prices will continue to stimulate demand for both major commodities. Lower oil production and higher demand are needed to re-balance the crude oil market.

The timing of market rebalancing for either commodity remains unknown. Over the short term, the Corporation anticipates continued elevated levels of price volatility. On the oil side, a significant factor is the unknown impact of drilled but uncompleted shale oil wells, as well as inventory levels, in the United States. The pricing required to encourage companies to complete these wells is unknown, as is how significantly the resulting new production would offset declining overall production. It is expected that there will be continued price volatility for the next several quarters as the various dynamics play out, which may not provide substantially higher realized prices for Questfire until mid-2016 or 2017. During the most recent quarter, crude oil prices, which are benchmarked in U.S. dollars, declined, with realized prices benefiting from a strengthening of the U.S. dollar relative to the Canadian dollar, which increases the Canadian price received on Questfire's crude oil.

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 50 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,	
	2015	2014	**2015**	2014
	$	$	**$**	$
Royalties	**481,399**	1,965,087	**2,945,794**	9,744,194
Per boe	**1.03**	3.88	**1.66**	5.23
Percentage of sales	**5.1%**	12.3%	**7.2%**	13.6%

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 than for the comparative periods as a result of lower commodity reference pricing used by the Alberta government to calculate royalties.

The Government of Alberta released its royalty review report on January 29, 2016, which contained key highlights of a proposed Modernized Royalty Framework (MRF) that will be effective on January 1, 2017. These highlights include no changes to the royalty structure of wells drilled prior to 2017 for a 10-year period from the royalty program's implementation date, 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 internal rate of return for any given play compared to the current royalty framework. The royalty review report did not provide details regarding post-payout royalty rates. The changes proposed to conventional oil and gas royalties will require further consultation between industry and government to fully understand their impacts. These changes to the Alberta provincial royalty structure could have a significant impact on Questfire's financial condition, results of operations and cash flows. An increase in the royalty rates applicable could make future capital expenditures or existing operations uneconomic.

Production and Operating Expense

	Three months ended December 31,		Year ended December 31,	
	2015	2014	**2015**	2014
	$	$	**$**	$
Production and operating expense	**5,240,410**	6,549,554	**20,988,872**	27,266,216
Per boe	**11.26**	12.94	**11.79**	14.64

Production and operating expenses decreased on a total and per-boe basis from the comparative periods in 2014 due to concentrated field efforts throughout the Corporation's properties to reduce operating costs, as well as due to new wells that came on production during the second half of 2014 and third quarter of 2015 with lower per-boe operating costs. Management continues to look at production and operating costs to identify additional savings. The savings from these future efforts is unknown and may not be significant due to the extent of savings achieved to date, as well as the size of fixed costs such as property taxes and lease rentals. To date in 2016, an estimated 10 percent in additional cost reductions has been achieved.

Transportation Expense

	Three months ended December 31,		Year ended December 31,	
	2015	2014	**2015**	2014
	$	$	**$**	$
Transportation expense	**475,739**	432,019	**1,685,686**	1,765,327
Per boe	**1.02**	0.85	**0.95**	0.95

Transportation expense was largely consistent over the comparative periods.

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 the commodity price environment that began during the fourth quarter of 2014 continued in 2015. If crude oil and natural gas prices decline significantly from present levels and remain low for an extended period, the carrying value of Questfire's assets may 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. As a result of the substantial slowdown across the energy sector, Questfire expects to see moderate additional reductions in demand for and, in turn, the costs of labour, services and materials. This may create additional opportunities to improve the Corporation's cost structure.

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 risk exposure inherent in movements in the price of natural gas was managed by Questfire in 2015 through the use of derivatives with investment-grade counterparties. No risk management contracts were entered into during 2015 as management believes current oil and natural gas prices are below industry full-cycle costs.

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, 2015, Questfire had no outstanding risk management contracts.

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 income (loss) and comprehensive income (loss).

	Three months ended December 31, 2015	2014	Year ended December 31, 2015	2014
	$	$	**$**	$
Realized gain (loss) on risk management contracts	**831,249**	(108,329)	**2,624,507**	(2,977,123)
Per boe	**1.79**	(0.21)	**1.47**	(1.60)
Unrealized gain (loss) on risk management contracts	**(676,649)**	3,046,597	**(3,390,491)**	3,640,317
Per boe	**(1.45)**	6.02	**(1.90)**	1.95

During the three months and year ended December 31, 2015, the realized gains on risk management contracts are associated with natural gas commodity prices being lower than the put contract price. The unrealized losses were a result of risk management premiums as well as the reduction of the number of months remaining in the risk management contracts, which resulted in unrealized gains being converted to realized gains.

Most risk management contracts entered into during 2014 were purchased puts. These provided downside price protection while allowing Questfire to realize all pricing upside in return for payment of the put option premium. This can be viewed as being similar to an insurance contract, with a premium paid in return for protection against negative events. Fixed-price contracts, although free of direct costs such as contract premiums, impose opportunity costs in the form of foregone pricing upside. Fixed-price contracts erase all exposure to pricing upside, while so-called costless collars limit the producer's pricing upside to the higher figure (the purchaser's call option). The Corporation did not enter into any risk management contracts in 2015 as a result of decreasing commodity prices.

It is Questfire's intention to purchase put options and costless collars in the future when commodity prices are higher.

General and Administrative (G&A) Expense

	Three months ended December 31, 2015	2014	Year ended December 31, 2015	2014
	$	$	**$**	$
G&A	**1,107,189**	1,138,142	**5,093,196**	6,016,485
G&A cash expense per boe	**2.38**	2.25	**2.86**	3.14
Non-cash G&A (office lease amortization) per boe	**-**	-	**-**	0.09
Total expense per boe	**2.38**	2.25	**2.86**	3.23

G&A expenses were lower than in the comparative periods in 2014 predominantly due to the elimination of bonuses in 2015, and an allocation of the portion of G&A expenses attributable to supporting exploration and evaluation (E&E) activities to E&E.

Share-Based Compensation

	Three months ended December 31, 2015	2014	Year ended December 31, 2015	2014
	$	$	**$**	$
Share-based compensation	**200,365**	172,474	**724,614**	567,645
Per boe	**0.43**	0.34	**0.41**	0.30

The increase in share-based compensation from the comparative periods in 2014 is a result of stock options issued in 2014 as well as in 2015. These options were issued in association with the Corporation increasing staffing as a result of its major acquisition conducted in April 2013, as well as the issuance of new options for existing employees and directors.

On November 20, 2015, 935,000 outstanding stock options with exercise prices ranging between $1.25 and $2.60 per Class A share granted to non-executive officer employees and consultants were repriced to an exercise price of $1.00 per Class A share. No options held by executive officers or directors were repriced. This repricing was done to reward staff for their efforts in reducing operating expenses to the end of the third quarter of 2015 that exceeded those of Questfire's peer companies on both a percentage and dollars-per-boe basis. The Board of Directors concluded that repricing of existing stock options was an ideal approach for staff, the Corporation, and shareholders as it allowed the Corporation to reward staff while conserving the Corporation's cash.

The Corporation granted 275,000 and 950,000 options in the respective three months and year ended December 31, 2015 at exercise prices between $1.00 and $1.68 per Class A share. The non-executive officer employee options granted with exercise prices in excess of $1.00 per Class A share were subsequently repriced to $1.00 on November 20, 2015. There were 3,566,000 options outstanding at December 31, 2015 and 3,488,500 as of the date of this MD&A. There were 1,886,000 options exercisable at December 31, 2015.

Exploration and Evaluation (E&E) Expenditures

	Three months ended December 31, 2015	2014	Year ended December 31, 2015	2014
	$	$	**$**	$
E&E expense	**639,670**	514,350	**1,219,228**	898,652
Per boe	**1.37**	1.02	**0.68**	0.48

The increase in E&E expenditures recognized over the comparative 2014 periods is due to $338,731 of E&E expenditures recognized in the fourth quarter of 2015 for mineral rights voluntarily relinquished by the Corporation as a result of low commodity prices.

Depletion and Depreciation (D&D)

	Three months ended December 31, 2015	2014	Year ended December 31, 2015	2014
	$	$	**$**	$
D&D	**2,880,401**	4,412,478	**11,554,711**	14,211,486
Per boe	**6.19**	8.72	**6.49**	7.63

The Corporation experienced decreased D&D from the comparative periods in 2014, resulting from a lower depletion rate on a per-boe basis in 2015 due to reserve increases in several CGUs. 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 upon acquisition of the assets in April 2013, and continued by the Corporation's low finding and development costs per boe in subsequent years.

Property and Equipment Impairment

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, 2015, the Corporation recorded a property and equipment impairment of $3,000,000 (year ended December 31, 2014 – $Nil) pertaining to the Open Lake CGU. As commodity price volatility remains above average, impairment charges or recoveries can be expected in future periods. During the fourth quarter of 2015, the Corporation reversed the property and equipment impairments recorded for the Brazeau River and Crossfield CGUs, of $0.7 million and $0.8 million, respectively. The Brazeau River CGU impairment reversal was a result of general reserve additions in the fourth quarter of 2015, while the Crossfield CGU impairment reversal was a result of reserve additions pertaining to the Elkton G Oil Unit gas cycling project.

Other Income

	Three months ended December 31, 2015	2014	Year ended December 31, 2015	2014
	$	$	**$**	$
Gain on sale of assets	**-**	12,447	**-**	1,999,410
Per boe	**-**	0.02	**-**	1.07
Gain on repurchase of Class B shares	**-**	-	**-**	7,294,966
Per boe	**-**	-	**-**	3.92
Gain on repurchase of convertible debentures	**-**	-	**-**	17,722,983
Per boe	**-**	-	**-**	9.52

The majority of the gain on sale of assets in 2014 pertains to the sale of the Corporation's Turner Valley interests, part of the Crossfield CGU, for proceeds of $3,752,297, or approximately $61,500 per flowing boe. The non-core, non-operated, low-working-interest Turner Valley assets were producing approximately 61 boe per day net at the time of sale on May 1, 2014, which was comprised of 5 bbls per day of crude oil, 23 bbls per day of NGL and 195 Mcf per day of natural gas.

The remaining gain on sale of assets in 2014 is the entire proceeds received on disposition of various pieces of spare equipment. There may be additional spare inventory that is disposed of in future periods, but this is anticipated to be significantly smaller than the 2014 sales.

The gain on repurchase of Class B shares during the second quarter of 2014 was for the repurchase of 1,505,400 Class B shares, by way of an issuer bid, which closed on May 5, 2014.

The gain on repurchase of convertible debentures during the first quarter of 2014 related to the debentures issued in 2013, with a $32.6 million face value ($31.3 million book value), which were issued in consideration of the 2013 acquisition of producing assets from Advantage Oil & Gas Ltd. On March 26, 2014, an agreement was reached to repurchase all of the 2013 debentures for consideration of $13.6 million, resulting in a gain of $17.7 million.

Finance Expense

	Three months ended December 31,		**Year ended December 31,**	
	2015	2014	**2015**	2014
	$	$	**$**	$
Interest on convertible debentures	**-**	-	**-**	540,808
Interest on bank debt	**515,546**	427,749	**1,718,095**	1,710,278
Interest on long-term contract obligation	**503,098**	544,300	**2,026,058**	1,578,090
Financing costs	**-**	-	**75,000**	591,345
Cash finance expense	**1,018,644**	972,049	**3,819,153**	4,420,521
Accretion on decommissioning provision	**407,564**	422,121	**1,731,861**	2,014,871
Accretion on Class B share liability	**108,436**	99,482	**420,072**	807,574
Accretion on convertible debentures	**-**	-	**-**	372,871
Non-cash finance expense	**516,000**	521,603	**2,151,933**	3,195,316
Total finance expense	**1,534,644**	1,493,652	**5,971,086**	7,615,837
Per boe	**3.30**	2.95	**3.36**	4.09

Convertible debenture interest and accretion decreased from the year ended December 31, 2014 due to the repurchase of the 2013 debentures on March 26, 2014 and the conversion into Class A shares of all of the remaining 2012 debentures on June 30, 2014, resulting in no convertible debenture accretion or interest during 2015.

Interest on the long-term contract obligation and financing costs relate 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 the 2013 debentures, 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 for 17.5 years, after which beneficial ownership will revert to Questfire.

Accretion on the decommissioning provision decreased in 2015 from the 2014 comparative periods due to longer forecast reserve lives for the East Central and Red Deer CGUs in the December 31, 2014 reserve report.

Accretion on the Class B shares decreased from the year December 31, 2014 because on May 5, 2014, the Corporation repurchased 1,505,400 Class B shares for $3.9 million. Class B share accretion for the fourth quarter is higher in 2015 than in 2014 due to the increased balance on which accretion is calculated. As of the date of this report, there were 550,440 Class B shares outstanding.

Deferred Income Tax

Deferred income tax recovery was $351,156 and $3,049,379, respectively, in the three months and year ended December 31, 2015, compared to expenses of $591,384 and $6,418,417 in the respective comparative periods in 2014. The reversal from expenses to recoveries is a result of the Corporation incurring losses in 2015 versus realizing income in 2014.

Income (Loss)

The Corporation incurred losses of $1,152,161 ($0.07 per share basic and diluted) and $10,386,781 ($0.60 per share basic and diluted), respectively, for the three months and year ended December 31, 2015, compared to income of $1,600,035 ($0.09 per share basic and $0.08 per share diluted) and $24,795,298 ($1.62 per share basic and $0.92 per share diluted) for the respective comparative periods in 2014. The current periods' losses resulted primarily from lower realized commodity prices. The income in the three months and year ended December 31, 2014 resulted primarily from a combination of the gain on repurchase of the Class B shares in the second quarter of 2014, the gain on repurchase of 2013 debentures in the first quarter of 2014, and from higher realized commodity prices.

Selected Annual Information

Years ended December 31,	**2015**	2014	2013 (1)
	$	$	$
Oil and natural gas sales	**40,717,011**	71,619,004	40,537,638
Royalties	**(2,945,794)**	(9,744,194)	(5,304,284)
Net revenues	**37,771,217**	61,874,810	35,233,354
Funds flow from operations	**11,543,473**	23,113,274	11,919,693
Per share, basic	**0.67**	1.51	0.92
Per share, diluted	**0.48**	0.83	0.25
Income (loss)	**(10,386,781)**	24,795,298	(2,178,474)
Per share, basic	**(0.60)**	1.62	(0.17)
Per share, diluted	**(0.60)**	0.92	(0.17)
Total assets	**115,610,438**	133,863,233	133,177,378
Total non-current financial liabilities (2)	**55,562,170**	58,166,930	46,090,945

(1) The results for 2013 include the effects of the acquisition of producing assets from Advantage Oil & Gas Ltd. for the period May 1, 2013 to December 31, 2013. The assets acquired comprised substantially all of the Corporation's activities during this period.

(2) Excludes decommissioning provisions and deferred tax liabilities.

Supplemental Quarterly 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,	
	2015	2014	**2015**	2014
	$	$	**$**	$
Income (loss)	**(1,152,161)**	1,600,035	**(10,386,781)**	24,795,298
Non-cash items:				
Unrealized loss (gain) on risk management	**676,649**	(3,046,597)	**3,390,491**	(3,640,317)
Share-based compensation	**200,365**	172,474	**724,614**	567,645
E&E	**338,731**	-	**338,731**	-
D&D	**2,880,401**	4,412,478	**11,554,711**	14,211,486
Impairment (reversal) of property and equipment	**(1,500,000)**	-	**3,000,000**	-
Acquired office lease amortization	**-**	-	**-**	162,267
Deferred income tax expense (recovery)	**(351,156)**	591,384	**(3,049,379)**	6,418,417
Repurchase of Class B shares	**-**	-	**-**	(7,294,966)
Repurchase of convertible debentures	**-**	-	**-**	(17,722,983)
Finance expense	**1,534,644**	1,493,652	**5,971,086**	7,615,837
Gain on sale of assets	**-**	(12,447)	**-**	(1,999,410)
Funds flow from operations	**2,627,473**	5,210,979	**11,543,473**	23,113,274

Netback Analysis

	Three months ended December 31, 2015	2014	Year ended December 31, 2015	2014
	$/boe	$/boe	**$/boe**	$/boe
Average sales price	**20.20**	31.45	**22.88**	38.45
Royalties	**(1.03)**	(3.88)	**(1.66)**	(5.23)
Production and operating expense	**(11.26)**	(12.94)	**(11.79)**	(14.64)
Transportation expense	**(1.02)**	(0.85)	**(0.95)**	(0.95)
Operating netback	**6.89**	13.78	**8.48**	17.63
G&A [1]	**(2.38)**	(2.25)	**(2.86)**	(3.14)
E&E [2]	**(0.65)**	(1.02)	**(0.49)**	(0.48)
Realized gain (loss) on risk management	**1.79**	(0.21)	**1.47**	(1.60)
Bad debt expense	**(0.01)**	-	**(0.11)**	-
Funds flow netback	**5.64**	10.30	**6.49**	12.41
Finance expense	**(3.30)**	(2.95)	**(3.36)**	(4.09)
Gain on sale of assets	**-**	0.02	**-**	1.07
Gain on repurchase of Class B shares	**-**	-	**-**	3.92
Gain on repurchase of convertible debentures	**-**	-	**-**	9.52
Office lease amortization	**-**	-	**-**	(0.09)
D&D	**(6.19)**	(8.72)	**(6.49)**	(7.63)
Share-based compensation	**(0.43)**	(0.34)	**(0.41)**	(0.30)
Unrealized gain (loss) on risk management	**(1.45)**	6.02	**(1.90)**	1.95
Impairment of property and equipment	**3.23**	-	**(1.69)**	-
E&E non-cash items	**(0.72)**	-	**(0.19)**	-
Deferred income tax (expense) recovery	**0.75**	(1.17)	**1.71**	(3.45)
Income (loss) per boe	**(2.47)**	3.16	**(5.84)**	13.31

(1) Excludes the office lease amortization included below.

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

Selected Quarterly Information

Three months ended	**Dec. 31, 2015**	Sept. 30, 2015	June 30, 2015	March 31, 2015	Dec. 31, 2014	Sept. 30, 2014	June 30, 2014	March 31, 2014
Financial ($000s, except per share amounts and share numbers)								
Oil and natural gas sales	**9,406**	9,854	10,603	10,854	15,918	17,614	17,131	20,956
Funds flow from operations	**2,627**	2,628	3,236	3,052	5,211	5,102	4,410	8,390
Per share, basic *($)*	**0.15**	0.15	0.19	0.18	0.30	0.29	0.33	0.65
Per share, diluted *($)*	**0.11**	0.11	0.14	0.13	0.24	0.24	0.19	0.18
Income (loss)	**(1,152)**	(5,330)	(1,904)	(2,000)	1,600	648	8,172	14,375
Per share, basic *($)*	**(0.07)**	(0.31)	(0.11)	(0.12)	0.09	0.04	0.61	1.11
Per share, diluted *($)*	**(0.07)**	(0.31)	(0.11)	(0.12)	0.08	0.03	0.36	0.32
Capital expenditures	**83**	2,310	914	1,649	2,864	9,927	3,240	3,176
Total assets *(end of quarter)*	**115,610**	119,845	125,498	129,884	133,863	137,201	131,663	140,599
Working capital deficit *(end of quarter)*	**9,653**	7,544	4,166	4,103	4,787	10,479	5,464	44,617
Long-term contract obligation *(end of quarter)* (1)	**14,156**	14,246	14,334	14,418	14,500	14,480	14,574	14,665
Non-current bank debt *(end of quarter)*	**41,406**	39,062	40,590	40,774	39,000	37,000	37,000	-
Shareholders' equity *(end of quarter)*	**14,251**	15,203	20,361	22,089	23,914	22,141	21,309	10,414
Weighted-average basic shares outstanding *(000s)*	**17,318**	17,318	17,318	17,318	17,318	17,298	13,418	12,963
Weighted-average diluted shares outstanding *(000s)*	**17,318**	17,318	17,318	17,318	21,550	18,838	23,062	48,344
Operations								
Production								
Natural gas *(Mcf/d)*	**23,245**	20,684	20,690	22,341	24,868	23,936	22,123	23,392
NGL *(bbls/d)*	**674**	627	599	689	712	712	601	669
Crude oil *(bbls/d)*	**512**	522	605	790	644	507	434	406
Total *(boe/d)*	**5,060**	4,596	4,652	5,203	5,501	5,208	4,722	4,974
Average realized prices *($)*								
Natural gas *(per Mcf)*	**2.57**	2.95	2.73	2.87	3.74	4.16	4.83	5.97
NGL *(per bbl)*	**31.74**	31.72	40.87	33.25	51.38	63.87	66.24	82.05
Crude oil *(per bbl)*	**41.02**	50.13	58.72	42.51	67.23	91.40	95.62	94.48
Operating netback *(per boe)*	**6.89**	8.65	9.53	8.96	13.78	15.74	16.74	24.87
Funds flow netback *(per boe)*	**5.64**	6.22	7.65	6.52	10.30	10.65	10.26	18.74

(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,	
	2015	2014	**2015**	2014
	$	$	**$**	$
Land	**14,127**	237,859	**69,307**	331,310
Geological and geophysical	**9,650**	2,856	**32,452**	406,771
Drilling and completions	**26,986**	1,642,695	**2,845,595**	12,333,379
Production equipment and facilities	**13,733**	926,061	**1,532,466**	4,869,426
Well workovers and recompletions	**18,247**	54,228	**472,911**	1,161,658
Office equipment	**-**	-	**2,317**	104,004
	82,743	2,863,699	**4,955,048**	19,206,548

At December 31, 2015, the Corporation had E&E assets of $1,340,456 (December 31, 2014 – $1,679,187). This included 101,232 net acres of undeveloped land.

At December 31, 2015, the Corporation had gross property and equipment of $146,145,913. 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 2015, Questfire spent approximately $2.5 million on drilling and completing its first 100 percent working interest horizontal Falher gas well in the Morningside field of central Alberta, which spud on August 26th, and came on production in mid-October producing at approximately 300 boe per day of liquids-rich natural gas. The remainder was spent on mandatory spending related to the sales line upgrades at the Corporation's Lookout Butte field and for facility maintenance and optimization projects and completing and equipping an oil well which had been drilled late in the fourth quarter of 2014.

Share Capital and Option Activity

As at the date hereof, the Corporation had 17,318,001 Class A shares, 550,440 Class B shares, and 3,433,500 stock options outstanding. Each Class B share is convertible (at Questfire's option) into Class A shares at any time before November 30, 2016. The number of Class A shares to be issued upon conversion of one Class B share is calculated by dividing $10 by the greater of $1 and the 30-day weighted-average market price of the Class A shares. If conversion has not occurred by the close of business on November 30, 2016, the Class B shares become convertible (at the shareholder's option) into Class A shares on the same basis. Effective at the close of business on December 31, 2016, all remaining Class B shares will be automatically converted into Class A shares.

Liquidity and Capital Resources

At December 31, 2015, the Corporation had a working capital deficit of $9,653,400. Funds flow from operations for the three months and year ended December 31, 2015 were $2,627,473 and $11,543,473, respectively. Full-year funds generated from operations are in excess of the current working capital deficit. Funds generated from operations during 2016 are anticipated to be used for debt reductions as well as a limited amount of capital expenditures.

The significant decline in commodity prices has 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 is in a position to resume its planned capital program as soon as commodity prices improve.

The Corporation's credit facility is a committed facility, which operates as a revolving facility for a 364-day term, extendible annually for a further 364-day revolving period, subject to a one-year term-out period should the lender not agree to an annual extension. The current conversion or extension date is May 31, 2016. 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 the ongoing cost reduction measures that management has been undertaking for the past year and a half. The Corporation's management expects that the lender will extend the credit facility; there is no assurance, however, that it will do so. Should the lender not extend the loan or reduce the amount available under the facility, the Corporation would need to seek alternative sources of debt or equity financing, or sell assets.

The credit facility had $41.4 million drawn and $3.6 million undrawn at December 31, 2015. The facility bears interest at a range of prime plus 1 percent to prime plus 4 percent per annum, depending on the Corporation's adjusted senior debt (which excludes amounts under the long-term contract obligation) to EBITDA ratio as defined by the agreement. The facility requires the Corporation to maintain, at the end of each quarter, a maximum consolidated net debt of $47.5 million (for purposes of the covenant, this is calculated as long-term bank debt and working capital, excluding convertible Class B shares and risk management contracts), and to maintain a debt to EBITDA ratio, as defined by the agreement, of less than 5.00:1 at December 31, 2015, March 31, 2016, and June 30, 2016; 4.50:1 at September 30, 2016; 3.50:1 at December 31, 2016; and 3.0:1 thereafter, and is secured by all of the Corporation's assets.

The Corporation's long-term contract obligation relates to the facilities joint venture agreement with a third party, to which the Corporation pays an annual facility fee of $2,326,300 for 17.5 years. Questfire has the option to terminate the joint venture agreement on payment of an amount which will provide the partner with a compound annual yield on its investment of 13.25 percent to the later of 48 months or the date the option is exercised. Upon the payment of aggregate facility fees to the partner of a minimum of $19.5 million, the partner has the option to sell back to Questfire its beneficial interest in the facilities for the sum equal to the total remaining scheduled facility payments, discounted at 17.5 percent to the time of exercise.

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.

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 to maintain flexibility in funding its capital programs. Future liquidity depends primarily on funds flow generated from operations, drawing on existing credit facilities and accessing debt and equity markets.

Going Concern

Due to the current commodity environment internal forecasts indicate the Corporation may breach its debt to EBITDA financial covenant in 2016. Additionally, forecasted funds flow from operations, when combined with cash finance expense and anticipated decommissioning costs and property and equipment expenditures, are negative in 2016 when using strip pricing forecasts. These factors contribute to the uncertainty as to the determination of the borrowing base in May 2016. As such, the Corporation has included a note on going concern uncertainty in its financial statements. Management's attention remains focused on managing the resources of the Corporation 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 the fourth quarter of 2015, the Government of Alberta released its Climate Leadership Plan which will affect all consumers and businesses that contribute to carbon emissions in Alberta. This plan includes imposing carbon pricing that is applied across all sectors, starting at $20 per tonne on January 1, 2017 and moving to $30 per tonne on January 1, 2018; the phase-out of coal-fired power generation by 2030, a cap on oil sands emissions production of 100 megatonnes; and a 45 percent reduction in methane emissions by the oil and gas sector by 2025. Questfire expects the Climate Leadership Plan to increase the cost of operating its properties located in Alberta and is evaluating the expected impact of this plan on its operations.

Commitments

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

	2016	2017	2018	2019	2020	Thereafter
	$	$	$	$	$	$
Office lease base rent	803,254	803,254	803,254	468,565	-	-

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 $5,064 and $41,054 were incurred by Questfire to the law firm in the respective three months and year ended December 31, 2015 (three months and year ended December 31, 2014 – $84,590 and $339,064, respectively), of which $4,776 and $40,766, respectively (three months and year ended December 31, 2014 – $84,590 and $185,041, respectively), was related to general and administrative expenses and $287 for both periods (three months and year ended December 31, 2014 – $Nil and $154,023, respectively) was related to financing expense. At December 31, 2015, $12,988 (December 31, 2014 – $22,050) related to these amounts was included in accounts payable and accrued liabilities and was due under normal credit terms.

Hedging

At December 31, 2015, the Corporation had no hedges in place relating to future periods (see "Risk Management" above). Subsequent to the end of the year, the Corporation entered into a new risk management contract as follows:

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$2.01/GJ

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, 2015 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, 2015 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, 2016 and have not been applied in preparing the financial statements for the year ended December 31, 2015. 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.

There are no other IFRS or IFRIC interpretations that are not yet effective 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, however, 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 term "operating netback" (oil and natural gas sales less royalties, production and operating, and transportation expenses) is not defined under IFRS, which have been incorporated into GAAP, as set out in Part 1 of the Chartered Professional Accountants Canada Handbook – Accounting, and may not be comparable with similar measures presented by other companies. Operating netback is a per-unit-of-production measures 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, which under current commodity price conditions is approximately 15 to 25 Mcf to 1 bbl. 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 actual results or events 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 contains 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. Readers are further cautioned not to place undue reliance on forward-looking statements, as no assurances can be given as to future results, levels of activity or achievements.

Forward-looking information may involve 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 such actual results, performance or achievements transpire or occur, or if any of them do so, 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. One Mcf of natural gas is about 1.05 GJ
MMBtu	million British thermal units. One GJ is about 0.95 MMBtu.

Other

AECO	refers to 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
Symbols: Q.A and Q.B