PetroFrontier

Management's Discussion & Analysis

December 31, 2022

PetroFrontier Corp. (the “Corporation”) is a public company, which is engaged in the business of exploring and developing petroleum and natural gas properties in western Canada. The Corporation has a fiscal year end of December 31, 2022.

This Management’s Discussion & Analysis (“MD&A”) is a review of how the Corporation performed during the period covered by the consolidated financial statements, and of the Corporation's financial condition and future prospects. The MD&A complements and supplements the consolidated financial statements of the Corporation and should be read in conjunction with the Corporation’s consolidated financial statements and the related notes for the years ended December 31, 2022 and 2021. The financial statements have been prepared in Canadian dollars in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board (“IASB”) and interpretations of the International Financial Reporting Interpretations Committee (“IFRIC”), which are also generally accepted accounting principles (“GAAP”) for publicly accountable enterprises in Canada.

The Corporation's Board of Directors has reviewed and approved the consolidated financial statements and MD&A, both of which are effective April 30, 2023.

Forward-Looking Statements

Certain statements contained in this document, including Management’s assessment of the Corporation’s future plans and operations, may constitute forward-looking statements. The use of any of the words "anticipate", "continue", "estimate", "expect", "may", "will", "project", "should", "believe", "plan" and similar expressions are intended to identify forward-looking statements. These statements involve known and unknown risks, uncertainties and other factors that may cause the actual results, performance or achievements of the Corporation, or industry results, to differ materially from those expressed or implied by such forward-looking statements. The Corporation believes the expectations reflected in these forward- looking statements are based on reasonable assumptions but no assurance can be given that these expectations will prove to be correct and the forward-looking statements included in this document should not be unduly relied upon. These statements speak only as of the date of this document.

Non-IFRS Measures

The financial data presented herein has been prepared in accordance with IFRS. The Corporation has also used certain measures of financial reporting that are commonly used as benchmarks within the oil and natural gas production industry in the following MD&A discussion. The measures are widely accepted measures of performance and value within the industry and are used by investors and analysts to compare and evaluate oil and natural gas exploration and producing entities. The most notable measure is “operating netback” which is a benchmark used in the crude oil and natural gas industry to measure the contribution of oil and natural gas sales calculated by deducting royalties and operating expenses and adding back lease rentals from non-producing properties from revenues on a dollar basis, divided by total production for the period on a boe or bbl basis. This measure is not defined under IFRS and should not be considered in isolation or as an alternative to conventional IFRS measures. This measure and its underlying calculations are not necessarily comparable or calculated in an identical manner to a similarly titled measure of another entity. When this measure is used, it is defined as “non IFRS” and should be given careful consideration by the reader.

Other terms used in this report are as follows:

bbl – barrel
bbls/d – barrels per day
CHOPS – Cold heavy oil produced with sand
WTI – West Texas Intermediate (a light oil reference price)
WCS – Western Canadian Select (a heavy oil reference price)
API – American Petroleum Institute

Corporate Overview

The Corporation is engaged in exploring for, and the production of, petroleum and natural gas in western Canada. The current core properties are Cold Lake and Wabasca, both conventional heavy oil projects.

Significant events which may impact the Corporation are described below in the section ***Subsequent Events***.

The Corporation has two wholly-owned inactive Australian subsidiaries, PetroFrontier (Australia) Pty Ltd and Texalta (Australia) Pty Ltd (collectively "PetroFrontier (Australia)"). When used herein, the term "Corporation" includes PetroFrontier (Australia) on a consolidated basis.

The Corporation operates from its offices located at 700, 903 – 8 Avenue SW, Calgary, Alberta, T2P 0P7.

The common shares of the Corporation trade on the TSX Venture Exchange under the trading symbol "PFC".

Overview of Consolidated Financial Results

The following selected financial data is derived from the audited consolidated financial statements of the Corporation and reference should be made to such financial statements for the years ended and as at December 31:

	2022	**2021**	**2020**
Income (loss) and comprehensive income (loss)	$ 578,906	$ (2,270,795)	$ (1,868,455)
Per common share (basic and diluted)	(0.00)	(0.01)	(0.01)
Working capital (deficiency)	(11,123,994)	(8,251,289)	(1,947,948)
Total assets	27,007,927	25,818,433	22,988,244
Total long-term liabilities	2,427,060	5,075,777	9,088,087
Shareholders' equity	$ 12,016,226	$ 10,939,768	$ 11,359,925

The Corporation's net loss is discussed further in the section *"Discussion of Operations"* and the working capital deficiency is discussed under *"Liquidity and Capital Resources"*.

Outlook and Current Environment

2022 was a considerably better year for PetroFrontier and the overall oil and gas industry. PetroFrontier saw its revenue double and realized a 64% year over year increase in production resulting from the completion and equipping of wells in early 2022 and certain targeted capital well workovers. Further, PetroFrontier significantly reduced its abandonment liabilities through its participation with the Cold Lake First Nations by abandoning (cutting and capping) 89 wellbores.

2023 has also started off well with our major lenders granting us a 2-year extension and significantly lowering the interest rate payable on our debt. Further, the Company is also pleased to announce, in conjunction with the issuance of these annual financial statements and MD&A, that PetroFrontier has engaged Mehran Joozdani, former Vice President, Heavy Oil Production and Exploitation for Husky Energy, as our new Chief Operating Officer. Mr. Joozdani has 25 years of oil and gas experience having started his career at Schlumberger and working his way up to the positions of Regional Operations Manager for both Canada and Central Asia before joining Husky. Mr. Joozdani will help lead PetroFrontier's transition from a delineation and reserves growth story to one of production growth utilizing multi-lateral horizontal drilling and enhanced oil recovery technology. Management's strategy, in conjunction with its capital raising efforts, is to commence this transition by kicking-off its initial multi-lateral well program after breakup and, subject to regulatory and stakeholder approvals, taking the initial steps to secure one or more small scaled enhanced oil recovery pilots. Both techniques have been used with great success to significantly improve production from, and recovery factors in, analogous Mannville formations in the Corporation's multi-zone core areas in Cold Lake and Wabasca.

Finally, the Board and management of PetroFrontier would like to thank its First Nation partners without whose support we would not have the opportunity to grow and develop such world class heavy oil plays.

Core properties

The Corporation has joint venture interests covering approximately 18 gross (16.5 net) sections arising under agreements with the wholly-owned energy companies of the Cold Lake First Nations ("CLFN"). As at December 31, 2022, 19 wells have been drilled under the joint ventures establishing multi-zone productivity and substantial reserves.

Likewise, PetroFrontier has a joint venture agreement with the wholly-owned energy company of the Bigstone Cree Nation ("BCN") dated May 7, 2018, that covers 1,024 gross (922 net) hectares in the Wabasca area of north-central Alberta. The Corporation's interests are located between CNRL's prolific Brintnell field currently producing approximately 50,000 bbls/d of heavy oil and Cenovus' proposed 10,000 bbls/d McMullen enhanced heavy oil recovery project.

Drilling Commitments

The Corporation obtained an extension to drill five earning wells at English Bay under an existing Cold Lake lease (the "English Bay Lease") to November 30, 2023. This drilling program is budgeted to cost approximately $3,200,000.

As set out under the Bigstone Development Agreement discussed below, the Corporation was required to spud five (5) test wells and complete, cap, plug or abandon the drilled wells. These wells were drilled by the respective expiry dates.

To meet its earning and continuance terms, further debt and/or equity financing will be required, otherwise leases may not be continued beyond their extended primary terms.

Site Rehabilitation Program

In May 2020, the Government of Alberta announced the Site Rehabilitation Program ("SRP") whereby qualified contractors (the "Contractors") could apply for grants to assist with the abandonment and reclamation activities of upstream oil and gas wells, pipelines and associated facilities.

The SRP will provide grant funding to successful Contractors in the oil field services sector who have entered into, and comply with, an oil field service contract with an oil and gas company, who has a qualified business. The grant payments are made directly to the Contractors.

Furthermore, the Corporation and its First Nation joint venture partner, Tri-Rez Energy Ltd., the wholly-owned energy company of Cold Lake First Nations, have identified up to 118 of the Corporation's wells that can be decommissioned and abandoned and 22 well sites that can be remediated and reclaimed under the SRP. The Cold Lake First Nations leases in which the Corporation has working interests are part of the SRP Period 6 in which $100 million in funding is available for applications received by March 31, 2022 for abandonment and reclamation activities on First Nations' lands and Metis settlements.

The Corporation and Tri-Rez Energy submitted applications for 118 wells and 22 well sites identified for abandonment, remediation and reclamation under SRP Period 6 with respect to which, $3,600,000 has been approved to date, of which 89 wells were ultimately approved and abandoned (cut and capped).

During the year ended December 31, 2022, $1,638,957 (net to the Corporation) of decommissioning liabilities were eliminated through the SRP program, which has been recorded within other income on the consolidated statements of loss and comprehensive loss.

Discussion of Operations

Revenue

2022	**Annual**	**Q4**	**Q3**	**Q2**	**Q1**
Revenue	7,516,486	1,403,557	$2,131,207	$2,165,951	$1,815,772
# bbls	89,428	23,451	25,972	19,653	20,352
Bbls/d	245	255	282	216	226
Realized revenue per bbl	$84.05	$59.85	$82.06	$110.21	$89.22
WCS -CAD$ per bbl	$97.11	$73.90	$92.25	$118.76	$103.18
Differential to WCS	13.5%	19.0%	11.0%	14.2%	13.5%

2021	**Annual**	**Q4**	**Q3**	**Q2**	**Q1**
Revenue	$3,085,698	$874,948	$902,745	$749,988	$558,017
# bbls	54,635	13,712	14,940	13,705	12,278
Bbls/d	150	149	162	151	136
Realized revenue per bbl	$56.48	$63.81	$60.42	$54.72	$45.45
WCS -CAD$ per bbl	$68.34	$76.14	$72.62	$67.13	$57.48
Differential to WCS	17.4%	16.2%	16.8%	18.5%	20.9%

Petroleum revenue for 2022 was $7,516,486 (2021- $3,085,698), an increase of $4,430,788 or 143.6%, with production averaging 245 bbls/d (2021 – 150 bbls/d). The Corporation realized an average price of $84.05 per bbl for 2022 (2021 - $56.48) while the WCS benchmark price for heavy oil averaged CAD$97.11 (2021 – CAD$68.34). The increase in revenue from 2021 to 2022 is attributable to an increase of 34,793 barrels of oil sold from a larger number of producing wells and from higher realized prices in 2022.

The realized sales price is lower than the WCS benchmark price as the Corporation's oil is of lower API gravity than that used in setting the WCS benchmark price.

Royalties

Royalty expense was $688,627 for 2022 (2021 – $259,593), being 9.2% and 8%, respectively of petroleum revenue for both years. Royalties are paid to Indian Oil and Gas Canada on behalf of the respective First Nation.

Production operating costs

Production operating costs were $5,151,638 ($57.61/boe) in 2022 compared to $2,557,627 ($46.81/boe) in 2021, an increase of $2,594,011 ($10.80/boe), or 101.4%. The operating cost increase in 2022 is primarily related to increased annual production. The increase in operating costs on a per boe basis is attributed to a return to regular operations after several COVID-19 cutbacks in 2021, initially higher production costs associated with initiating and optimizing production from a new field at Wabasca and to a general increase in field costs associated with the rising oil prices as well as to operational workover expenses that supported the increase to production.

General and administrative expense

The main components of the Corporation's general and administrative expenditures are as follows:

	Three months ended December 31		**Years ended December 31**	
	2022 ($)	**2021 ($)**	**2022 ($)**	**2021 ($)**
Salaries and benefits	185,930	166,073	747,526	656,910
Office	78,606	98,238	322,454	167,255
Professional fees	72,849	51,506	258,072	142,919
Corporate and regulatory	3,837	3,282	30,844	23,005
	341,222	**319,099**	**1,358,896**	**990,089**

Overall, general and administrative expenses increased by $368,807 from $990,089 in 2021 to $1,358,896 in 2022.

In 2022, salaries and wages increased by $90,616 as compared to 2021. The Corporation received the Canada Emergency Wage Subsidy ("CEWS") which reduced salaries by $nil in 2022 (2021 – $17,120). Salaries and wages were reinstated to near pre-COVID levels during 2022.

Overall, office costs increased to $322,454 in 2022 as compared to $242,377 in 2021. This $155,199 increase over last year is largely due to increased insurance expense and to computer and software costs. Relief provided by the Canada Emergency Rent Subsidy totaled $nil in 2022 (2021 -$3,145).

Professional fees increased by $155,199 in 2022 over fees in 2021. This increase is attributable to increases in audit and reservoir engineering fees, and to the addition of consulting fees related to the process of securing financing and to establishing an enhanced oil recovery strategy.

Depletion and depreciation

Assets were depleted by $672,740 in 2022 (2021 - $407,051). Depletion relates to the resource assets and is based on the unit-of-production method based on proven and probable reserves. The depletion expense per bbl in 2022 was $7.57 as compared to $7.46 in 2021.

Accretion on decommissioning liabilities

Accretion expense was $114,393 in 2022 (2021 - $67,408) and reflects the increase in the liability due to the passage of time. The accretion expense has decreased due to settlements from the SRP program (described below) and revisions to estimates of the liabilities.

Finance income and expense

		2022		**2021**
Interest on debentures		120,000		150,000
Interest on convertible note payable		87,925		87,496
Interest on loans		523,168		143,878
Accretion		134,913		401,343
Extension fee on convertible note payable		18,128		19,841
Extension fee on debenture payable		40,000		50,000
	$	**924,134**	**$**	**852,558**

Finance expense was $924,134 in 2022 as compared to $852,558 in 2021, an increase of $71,576. The increase in the expense in 2022 was impacted addition of an additional loan received in 2022 (described below under *Loans*).

Net income (loss)

The Corporation recorded a net income of $578,906 as compared to a loss of $2,270,795 in 2021. The increase in income reflects the government grant for the SRP program of $2,466,334 (recorded in Other income) netted against the increased share-based compensation and finance expenses.

Operating Netback

The following table details the Corporation's operating netback which is defined in a preceding section *"Non-IFRS Measures":*

The Corporation's operating netback increased marginally by $53,585 in Q4 2022 when compared to Q4 2021 despite the increase in production by 9,739 bbls or by 71%. This can be attributed to high field costs in the quarter.

Year Ended	**December 31, 2022**	**Per boe**	**December 31, 2021**	**Per boe**
Production (boe)	89,428		54,635	
Average daily production (boe/d)	245		150	
Petroleum and natural gas revenue	$7,516,486	$84.05	$3,085,698	$56.48
Royalties	$688,627	$7.70	$259,493	$4.75
Production operating costs	$5,151,638	$57.61	$2,362,627	$43.24
Less: non-producing lease costs	(270,810)		(292,298)	
Operational netback	$1,405,411	$21.77	$755,876	13.84

The Corporation's netback was $649,535 higher in 2022 as compared to 2021. The increase is mainly related to an increase realized price per boe of $22.76 and an increase to production volumes of 33.7% in 2022. Production costs were $14.37 higher per boe in 2022.

The petroleum revenue for the heavy oil produced at Cold Lake is based on the WCS Benchmark price.

Three Months ended	**December 31, 2022**	**Per boe**	**December 31, 2021**	**Per boe**
Production (boe)	23,451		13,712	
Average daily production (boe/d)	255		149	
Petroleum and natural gas revenue	$1,403,557	$59.85	$874,948	$63.81
Royalty expense	$127,597	$5.44	$67,363	$4.91
Production operating costs	$1,529,664	$65.23	$1,093,520	$79.75
Less: non-producing lease costs	(87,868)		(66,514)	
Operational netback	$(165,837)	$(7.07)	$(219,421)	$(16.00)

Details of quarterly pricing in 2022 and 2021 is as follows:

2022	**Q4**	**Q3**	**Q2**	**Q1**
WTI - $US/bbl	$82.65	$91.55	$108.41	$94.29
WCS Dollar Differential to WTI - US$/bbl	$28.22	$20.62	$15.41	$12.75
WCS % Differential	34.1%	22.5%	14.2%	13.5%

2021	**Q4**	**Q3**	**Q2**	**Q1**
WTI - $US/bbl	$77.19	$70.56	$66.12	$57.79
WCS Dollar Differential to WTI –US$/bbl	$16.75	$12.92	$11.44	$12.41
WCS % Differential	21.7%	18.3%	17.3%	21.5%

Changes to crude oil prices can have a significant impact on the bottom line. In this more favourable price environment, Management took steps to increase production in late 2021 by reactivating three (3) wells, and completing and equipping three (3) wells. These additional producing wells initially improved the netback given the effect of spreading fixed operating costs over a larger production base. In 2022, with continued high oil prices, the associated field costs also increased, ultimately reducing some the effect of the additional production.

Quarterly financial results

		Three months ended December 31, 2022		**Three months ended December 31, 2021**
Petroleum and natural gas revenue	$	1,403,557	$	874,948
Royalties		127,597		67,363
Net revenue		1,275,960		807,585
Expenses:				
Production operating costs		1,529,664		1,213,400
General & Administrative		341,222		319,096
Depletion and depreciation		170,453		86,632
Accretion		41,548		20,375
Share-based compensation		180,680		123,633
Finance costs		79,338		250,664
Interest and other revenue		(427,346)		(384,479)
Adjustments to government grant		(571,013)		-
Comprehensive loss	$	(68,586)	$	(821,736)

A significant factor in comparing revenue in Q4 2022 to Q4 2021 relates to the higher sales price in 2022. The realized price per boe dropped to $59.85 in 2022 compared to $63.81 in Q4 2021, but was offset by the increase of 9,739 barrels sold in Q4 2022 compared to Q4 2021.

Accretion was $41,548 in Q4 2022 as compared to $20,375 in Q4 2021 reflecting changes to the risk-free interest rates and to changes in estimates resulting from the SRP program.

The increase in share-based compensation expense relates to the options issued in late 2022.

The finance costs increased in Q4 2022 as compared to Q4 2021 as two additional loans were added during the year.

Financial Position Results

Cash

As at December 31, 2022, the Corporation had cash $543,139 as compared to cash of $1,023,936 as at December 31, 2021. The decrease in cash at year end reflects a dip in production and realized prices in November and December and also the need for further capital investment.

Trade and other receivables

The balance of trade and other receivables were $753,930 at December 31, 2022 as compared to $455,690 at December 31, 2022. The receivable balance was higher at December 31, 2022 as certain December sales were paid in early January 2023.

Prepaid Expenses and Deposits

Prepaid expenses and deposits at December 31, 2022 were $143,578 (December 31, 2021 - $71,973) and is primarily comprised of prepaid industry fees, insurance and rent.

Property and equipment

Capital expenditures during the year ended 2022 increased property and equipment by $2,248,489. These costs are a result of certain well workovers and due to the completion of the 3 wells that the Corporation completed and equipped 3 wells at the end of 2021.

Trade and other payables

Trade and other payables at December 31, 2022 were $2,818,503 as compared to $3,053,362 at December 31, 2021. The balance, which decreased slightly in 2022, is comprised primarily of the additional operating costs incurred in late 2022 as well as certain capital costs incurred at the beginning of 2022.

DEBT

Bank loan

In 2020, the Corporation received a bank loan of $60,000 that is guaranteed by the Canadian Government under the Canada Emergency Business Account program in response to the Covid-19 pandemic. The bank loan is interest-free and 25% of the initial tranche of $40,000 and 50% of the second tranche of $20,000 were eligible for loan forgiveness if fully repaid on or before December 31, 2022. No principal payments were required until December 31, 2022. During the year ended December 31, 2022, the loan repayment date was extended to December 31, 2023.

If the bank loan is not repaid by December 31, 2023, the bank loan may be converted into a two-year term loan at an interest rate of 5% per annum payable monthly with no principal payments until December 31, 2025.

Convertible note payable

	December 31, 2022	December 31, 2021
Balance, beginning of year	**$ 1,364,654**	**$ 1,242,122**
Accretion	10,224	15,195
Interest	87,925	87,496
Extension fee	18,128	19,841
Balance, end of year - current	**$ 1,480,931**	**$ 1,364,654**

Convertible Note

On June 3, 2019, the Corporation finalized a credit facility with a corporation, related by common directorship, (the "Lender"), which provides for a credit facility not exceeding $2,000,000. The advances under the credit facility bear interest at 8% per annum payable at maturity and are secured by a General Security Agreement.

The Lender will have the option to convert the advances under the credit facility into common shares of the Corporation ("Common Shares"). The conversion price per Common Share shall be: (i) $0.065 for the first year of the term of the loan; and (ii) $0.10 for the second year of the term of the loan.

On June 30, 2020, the Corporation entered into an amending agreement with Kasten to extend the convertible note payable until August 31, 2022 and revise the conversion price to (i) $0.05 for 12 months after the exchange feature; and, (ii) $0.10 for the remaining term until maturity. In addition, an annual extension fee of 2% of the amount outstanding under the convertible note will be payable to the Kasten. The terms and future cashflows under the amended agreement to the initial convertible note is not substantially different from the terms of the existing convertible note, therefore the amendment is considered to be a debt modification.

As a result, a loss on debt modification of $31,661 was recorded for the difference between the carrying value of the convertible note at the date of the amendment and the fair value of the cashflows under the amended terms. Subsequent to June 30, 2020, the convertible note is carried at amortized cost using the effective interest rate method.

The convertible note expired on August 31, 2022. Subsequent to the year ended December 31, 2022, the note was amended and extended (see subsequent events). From expiry to year-end, the note continued as a demand loan by written agreement and interest was accrued at a rate of 8% per annum.

Debenture

		December 31, 2022		December 31, 2021
Balance, beginning of year	$	**2,208,815**	$	2,404,846
Settlement in exchange for common shares *(note 11)*		**-**		(500,000)
Accretion after extinguishment		**6,866**		103,969
Accrued interest payable		**120,000**		150,000
Extension fee payable		**40,000**		50,000
Balance, end of year - current	**$**	**2,375,681**	**$**	2,208,815

On July 21, 2016, the Corporation had issued a 3% secured convertible debenture in the principal amount of $3,000,000 to Kasten. The debenture was to mature no later than June 30, 2019 and is secured against the property of the Corporation. In June 2019, the debenture holder extended, at no cost to the Corporation, the maturity date of the debenture for one year subject to a 60-day notice period dependent on certain events occurring, with interest payable at maturity and cancelled the conversion feature contained in the original debenture issued in 2016 ("Original Extending Agreement").

On remeasurement, the liability component of the debenture was recognized at its fair value based on a market interest rate of 10%. The difference between the face value of the debenture and the fair value, being $195,000, will be accreted over the life of the debenture.

Effective June 30, 2020, the Corporation entered into an "Amended Extending Agreement" where the maturity date of the debenture was extended for two years to August 31, 2022. The amendments included an extension fee to be payable at the maturity date equal to two percent (2%) of the principal amount outstanding, per year, a revision in the interest rate to 8% per annum, and an option to convert the principal amount of the debenture, extension fee and outstanding interest under the debenture into common shares of the Corporation at a conversion price of (i) $0.05 between June 30, 2020 and June 30, 2021; and (ii) $0.10 between July 1, 2021 and the maturity date.

The amount outstanding under the debenture was partially settled on September 24, 2020 by one million dollars ($1,000,000) by issuing 25,000,000 common shares at a price of $0.04 per share. During the year ended December 31, 2021, and pursuant to the conversion feature of the debenture, $500,000 of the resulting amount due under the debenture was converted into shares by issuing 10,000,000 common shares at $0.05.

As the terms and cash flows of the Amended Extending Agreement to the Original Extending Agreement was substantially different from the terms of the Original Extending Agreement, the amendment was considered to be a debt extinguishment. As a result of remeasurement, the liability component of the debenture was recognized at its fair value based on a market interest rate of 12.96%, with the residual of $53,591 being recorded as equity. Subsequent to June 30, 2020, the debenture is carried at amortized cost using the effective interest rate method.

The debenture expired on August 31, 2022. Subsequent to the year ended December 31, 2022, the debenture was amended and extended. From expiry to year-end, interest was accrued at a rate of 8% per annum.

Loans

		Loan #1		**Loan #2**		**Total**
Balance, December 30, 2020	**$**	**-**	**$**	**-**	**$**	**-**
Advances in the year		1,150,000		2,000,000		3,150,000
Accretion of debt issuance expense		-		282,179		282,179
Debt issuance costs		-		(400,000)		(400,000)
Interest		17,211		126,667		143,878)
Balance, December 31, 2021	**$**	**1,167,211**	**$**	**2,008,846**	**$**	**3,176,057**
Advances in the year		2,350,000		-		2,350,000
Repayment, including interest		-		(277,522)		(277,522)
Accretion of debt issuance expense		-		117,823		117,823
Interest		371,502		151,667		523,169
Balance, December 31, 2022	**$**	**3,888,713**	**$**	**2,000,814**	**$**	**5,889,527**

Loan #1

During the year ended December 31, 2021, the Corporation was advanced $1,150,000. This amount was initially intended to be part of a financing announced on October 8, 2021 and was to be used to commence completion operations on certain wells that have already been drilled by the Corporation, but had yet been completed, together with workover operations on certain wells that are currently shut-in. The loan was subsequently combined under one loan, under the terms of one year at an interest rate of 12%. Interest expense of $371,502 has been expensed for the year.

Subsequent to the year ended December 31, 2022, this loan became part of a financing that is discussed in detail in Subsequent Events *(note 19)* as the first tranche of the loan expired on October 31, 2022.

Loan #2

During the year ended December 31, 2021, the Corporation finalized a credit facility with a non-related corporation (the "Lender"), which provides for a credit facility not exceeding $2,000,000. The advances under the credit facility bear interest at 8% per annum payable at maturity and are secured by a General Security Agreement. The advances were to be used solely for the drilling of four (4) wells. The principal and interest mature on the earlier of twelve months from the date of the last advance, being May 2021 and April 30, 2022.

The Corporation paid a structuring fee of $400,000 equal to 20% of the total amount of the credit facility which was paid by the issuance of 5,333,332 common shares of the Corporation at the closing price of the Corporation's common shares on the date of the acceptance of the credit facility being $0.075.

During the year ended December 31, 2022, $250,000 plus interest was repaid and the loan expired on April 30, 2022. Subsequent to the year ended December 31, 2022, the note was amended and extended (see subsequent note 19). From expiry to year-end, interest was accrued at a rate of 8% per annum.

Decommissioning Liabilities

The Corporation's total decommissioning liability is estimated based on the Corporation's net ownership in wells and facilities and management's estimate of costs to abandon and reclaim those wells and facilities, as well as an estimate of the future timing of the costs to be incurred.

By their nature, these estimates are subject to measurement uncertainty and the effect on the financial statements could be significant. The total undiscounted amount of the estimated cash flows required to settle its decommissioning liabilities are approximately $5,469,125 (December 31, 2021 - $5,469,125) which will be settled over the operating lives of the underlying assets, estimated to occur primarily over the next ten years. Risk-free interest rates of 1.15% to 1.27% (2021 - credit adjusted interest rate of 1.15% to 1.27%) and an inflation rate of 2% (2020 – 2%) were used to calculate the decommissioning liability. Revisions to the decommissioning liabilities of $512,628 resulted from changes in estimates with an offsetting decrease to property and equipment. Settlement of the liability will be funded from general corporate funds at the time of retirement or removal.

Changes to the liabilities were as follows:

Decommissioning Liabilities		**2022**		**2021**
Balance, beginning of year	**$**	**5,015,777**	$	5,711,119
Revisions to previously recorded liabilities		**(299,153)**		(512,628)
Abandoned under SRP program (see below)		**(2,463,957)**		(352,054)
Additions		**-**		101,932
Accretion		**114,393**		67,408
		2,367,060		5,015,777
Current portion (note 15)		**-**		-
Balance, end of year	**$**	**2,367,060**	**$**	5,015,777

Site Rehabilitation Program

In May 2020, the Government of Alberta announced the Site Rehabilitation Program ("SRP") whereby qualified contractors (the "Contractors") could apply for grants to assist with the abandonment and reclamation activities of upstream oil and gas wells, pipelines and associated facilities.

The SRP will provide grant funding to successful Contractors in the oil field services sector who have entered into, and comply with, an oil field service contract with an oil and gas company, who has a qualified business. The grant payments are made directly to the Contractors.

Furthermore, the Corporation and its First Nation joint venture partner, Tri-Rez Energy Ltd., the wholly-owned energy company of Cold Lake First Nations, have identified up to 118 of the Corporation's wells that can be decommissioned and abandoned and 22 well sites that can be remediated and reclaimed under the SRP. The Cold Lake First Nations leases in which the Corporation has working interests are part of the SRP Period 6 in which $100 million in funding is available for applications received by March 31, 2022 for abandonment and reclamation activities on First Nations' lands and Metis settlements.

The Corporation and Tri-Rez Energy submitted applications for 118 wells and 22 well sites identified for abandonment, remediation and reclamation under SRP Period 6 with respect to which, $3,600,000 has been approved to date, of which 89 wells were ultimately approved and abandoned (cut and capped).

During the year ended December 31, 2022, $1,638,957 (net to the Corporation) of decommissioning liabilities were eliminated through the SRP program, which has been recorded within other income on the consolidated statements of loss and comprehensive loss.

Common share information

Issued – common shares

	Year Ended December 31, 2022		Year Ended December 31, 2021	
	Number of shares	**Amount ($)**	**Number of shares**	**Amount ($)**
Common Shares				
Balance, beginning of year	**233,685,112**	**135,383,515**	**213,372,197**	**134,110,046**
Issued for cash	-	-	4,979,583	373,469
Issued as payment of structuring fee	-	-	5,333,332	400,000
Issued in settlement of debt	-	-	10,000,000	500,000
Balance, end of year	**233,685,112**	**135,383,515**	**233,685,112**	**135,383,515**

There was no change to share capital in 2022.

Year ended December 31, 2021:

The Corporation issued 4,979,583 common shares at a price of $0.075 per common share as part of a private placement. Gross proceeds of $373,469 were used to fund development and additional working capital.

Payment of the $400,000 structuring fee for loan #2 was made by issuing 5,333,332 common shares.

At the date of this MD&A, there are 233,685,112 Common Shares outstanding.

Stock options

Officers and directors of the Corporation have been granted options to purchase common shares. Options granted have a term of five years to expiry and typically vest equally over a two-year period on the basis of one-third on the date of grant, one-third on the first and second anniversary date of the grant. The exercise price of each option equals the market price or greater of the Corporation's common shares on the date of grant.

The following table summarizes the changes to the Corporation's option plan:

	Year ended December 31, 2022		**Year ended December 31, 2021**	
	#	Weighted average exercise price	#	Weighted average exercise price
Outstanding, beginning of year	17,800,000	$ 0.068	14,400,000	$ 0.120
Granted	5,200,000	0.080	12,800,000	0.075
Expired	-	-	(9,400,000)	-
Outstanding, end of year	**23,000,000**	**$ 0.071**	**17,800,000**	**$ 0.068**
Exercisable, at year end	**15,266,667**	**$ 0.067**	**7,600,000**	**$ 0.064**

The following table summarizes stock options outstanding and exercisable under the plan at December 31, 2022.

Options outstanding (#)	**Exercise price**	**Weighted average remaining contractual life (years)**	**Exercisable Options (#)**	**Expiry Date**
5,000,000	$ 0.050	2.7	5,000,000	September 7, 2025
12,800,000	$ 0.075	3.6	8,533,333	August 11, 2026
5,200,000	$ 0.080	4.9	1,733,333	December 5027
17,800,000	**$ 0.071**	**3.7**	**15,266,667**	

The following table summarizes stock options outstanding and exercisable under the plan at December 31, 2021.

Options outstanding (#)	**Exercise price**	**Weighted average remaining contractual life (years)**	**Exercisable Options (#)**	**Expiry Date**
5,000,000	$ 0.050	3.7	3,333,333	September 7, 2025
12,800,000	$ 0.075	4.6	4,266,667	August 11, 2026
17,800,000	**$ 0.066**	**4.3**	**7,600,000**	

The fair value of the stock options issued have been estimated at the date of grant using the Black-Scholes option pricing model based on the following assumptions:

Date of grant	**December 5 2022**	**August 11, 2021**
Dividend yield	**-**	**-**
Expected volatility	**149%**	**145%**
Risk-free interest rate	**3.06%**	**1.09%**
Expected life	**5 years**	**5 years**
Forfeiture	**nil**	**nil**

During the year ended December 31, 2022, share-based compensation of $497,553 (2021 - $577,169).

Liquidity and capital resources

As at December 31, 2022, the Corporation had cash of $543,139 (December 31, 2021 –$1,023,936) reflecting proceeds from loan #1 described above, despite higher realized prices on increased production.

In 2021 the Corporation received proceeds from 2 loans and completed a private placement for proceeds of $373,469.

These undertakings, while significant, may not be sufficient in and of themselves to enable the Corporation to fund all aspects of future operations, and accordingly, management will need to pursue other financing alternatives to fund the Corporation so that it may continue as a going concern. The necessary financing may require the issuance of equity and/or debt instruments or farmout arrangements. There is no assurance that such initiatives may be successful.

The Corporation expects to generate funds from future operations in order to assist in funding general operations, however, the Corporation will require additional funds in order to fund the working capital deficiency and to meet the expenditures further described below under *Material Contracts, Commitments and Contingencies.*

The pace of future capital investment and the related financial liabilities incurred from the capital investment program will be dependent upon the Corporation's capacity to secure additional equity/debt financing or farmout arrangements on favorable terms. The Corporation had no defaults or breaches on its financial liabilities in 2021.

Subsequent events

Debt Restructure

Subsequent to the year ended December 31, 2022, the Corporation announced that it has arranged to extend a total $6,353,000 of its principal debt obligations for a period of two additional years. The debt obligations included demand loans related to a debenture that matured on August 31, 2022 and previous credit facilities which matured on August 31, 2022, April 30, 2022 and October 31, 2022. The agreements extend the repayment dates to March 31, 2025 and include that interest will be payable at a rate of 8% per annum and will be secured by general security agreements. The extension agreements provide that the Lenders will have the ability to convert the indebtedness for the first year at a price of $0.075 per common share, being the last closing price of Corporation's common shares, and at a price of $0.10 per common share for the second year, in accordance with the requirements of, and subject to approval by, the TSX Venture Exchange.

Material Contracts, Commitments and Contingencies

Office lease

The Corporation had an office rental arrangement that required monthly payments of $8,000 to May 31, 2022 terminable by the landlord or the Corporation upon 60 days written notice. In March 2022, the Corporation extended the arrangement to December 31, 2022. As the term of the lease is less than 12 months the payments have been expensed.

During the year ended December 31, 2022, the Corporation expensed $66,925, net of recoveries, relating to operating leases (2021 - $68,005).

The Corporation has entered into a new office rental arrangement for a three-year fixed term commencing January 1, 2023 that requires gross monthly payments of $10,812.

Drilling commitments

The Corporation obtained an extension to drill five earning wells at English Bay under an existing Cold Lake lease (the "English Bay Lease") by November 30, 2023. This drilling program is budgeted to cost approximately $3,200,000.

As set out under the Bigstone Development Agreement discussed below, the Corporation was required to spud five (5) test wells and complete, cap, plug or abandon the drilled wells. These wells were drilled by the respective expiry dates.

To meet its earning well terms, further debt and/or equity financing will be required, otherwise the English Bay Lease may not be continued beyond the November 20, 2023 extended primary term.

Decommissioning obligations

Pursuant to the Inactive Well Compliance Program the Alberta Energy Regulator (the "AER") identified 22 wells in which the Corporation has a working interest that required some form of surface and/or downhole reclamation work. As a result of the Covid-19 pandemic, the AER has extended the date for compliance of the reclamation work and the Corporation is anticipating financial assistance for the reclamation work under the Site Rehabilitation Program as discussed in further detail in Decommissioning Liabilities *(note 10)*. The Corporation had estimated the reclamation work for these 22 wells would cost approximately $330,000 and that amount was previously included in the current portion of decommissioning liabilities on the consolidated statements of financial position at December 31, 2020.

Litigation

During the year ended December 31, 2014, Macquarie Capital Markets Canada Ltd. filed a Statement of Defense and Counterclaim against the Corporation in response to a Statement of Claim filed by the Corporation against Macquarie in the Court of Queen's Bench of Alberta on July 7, 2014. The Corporation has not recorded a contingent liability associated with the Counterclaim as the Corporation is of the opinion the Counterclaim is without merit. The Corporation is continuing with its lawsuit against Macquarie and its defense of the Counterclaim.

Development Agreement

On May 9, 2018, the Corporation entered into an agreement (the "Bigstone Development Agreement") with Bigstone Oil & Gas Ltd., the wholly owned energy Corporation of the Bigstone Cree Nation, for consideration of $250,000. The Bigstone Development Agreement provides for the development of an initial 3,040 acres of oil and gas rights from surface to the base of the Mannville in the Wabasca area of north-central Alberta under lease to Bigstone Oil & Gas Ltd. (the "Lease"). The Lease provides for an Alberta Provincial Crown equivalent royalty with a minimum rate of 10%. Under the terms of the Bigstone Development Agreement, the Corporation, as operator, has the right to earn a 90% before payout working interest and 50% after payout working interest in the five earning wells drilled in the first quarter of 2021 and a 50% working interest in the balance of the Lease.

The Corporation commenced developing the property by drilling one earning well in 2020, constructing a new 2.2 km road and multi-well drilling pad from which up to 8 wells can be drilled. Four (4) additional wells were drilled off the multi-well pad in the first quarter of 2021, satisfying its earning terms under the Bigstone Development Agreement.

During the year end December 31, 2021, with the discovery of economic recoverable reserves the Corporation transferred approximately $1.6 million of E&E assets to property and equipment. In accordance with the Corporation's accounting policy, all costs were assessed for impairment at the date of transfer to property and equipment.

Financial Instruments and Other Instruments

The Corporation's financial instruments consist of cash, trade and other receivables, trade and other payables, convertible notes payable and the debenture. It is management's opinion that the Corporation is not exposed to significant interest, currency or credit risks arising from these financial instruments and that the fair value of these financial instruments approximates their carrying values, as applicable.

Interest rate risk

At December 31, 2022 and 2021, the Corporation had no outstanding floating interest rate debt and is not exposed to interest rate risk at this time.

Liquidity risk

Liquidity risk relates to the risk the Corporation will encounter difficulty in meeting obligations associated with financial liabilities. The financial liabilities on its statement of financial position are limited to trade and other payables, convertible note payable and the debenture, all of which are current in nature.

With a working capital deficiency of $11,423,994 at December 31, 2021 (2021 – $8,251,289), the Corporation will require increased production from its petroleum properties and/or the continued support of its debenture holder and additional financing in order to fund its existing financial liabilities and ongoing operating and general administrative expenses.

The pace of future capital investment and the related financial liabilities incurred from the capital investment program will be dependent upon the Corporation's capacity to secure additional equity/debt financing or farmout arrangements on favorable terms.

Market risk

Market risk is comprised of currency risk, interest rate risk and other price risks which consist primarily of fluctuations in petroleum and natural gas prices. The current bank loan is interest free until December 31, 2022 and there was no bank debt as at December 31, 2019. Therefore, there is no current direct exposure to fluctuations in interest rates. The Corporation is exposed to fluctuations in commodity prices which affects the Corporation's revenue and any adverse fluctuations in interest rates, and commodity prices may indirectly affect the Corporation's ability to obtain equity financing and future bank debt, if required, and on favorable terms. The Corporation does not have any derivatives in place to manage price risk.

Summary of Quarterly Results (unaudited)

Fiscal Quarter Ended - $	December 31, 2022	September 30, 2022	June 30, 2022	March 31, 2022
Revenue	1,403,557	2,131,207	2,165,951	1,815,772
Net Income (loss)	(68,585)	118,117	483,991	45,385
Net income (loss) per share	(0.00)	0.00	0.00	0.00
Fiscal Quarter Ended - $	**December 31, 2021**	**September 30, 2021**	**June 30, 2021**	**March 31, 2021**
Revenue	874,948	902,745	749,988	558,017
Net loss	(841,188)	(617,728)	(314,749)	(281,880)
Net loss per share	(0.00)	0.00	0.00	0.00

In 2022, the Corporation's revenue benefited from higher realized oil prices and increased production. Certain operating workovers in the fourth quarter increased the operating costs that contributed to the higher net loss in that period. Increased production from additional wells and workovers contributed to the higher revenues in the first three quarters of 2022, while certain wells that were temporarily inactive during the fourth quarter impacted the revenue and resulting loss in Q4.

Related parties

Until February 28, 2021, the Corporation was related to Kasten Energy Inc. ("Kasten") when a director of the Corporation was also a director of Kasten. Pursuant to the Agreement of Purchase & Sale regarding the Kasten assets, Kasten acts as a bare trustee which includes forwarding monthly cash receipts from certain petroleum and natural gas sales to the Corporation. Other related party transactions are as follows:

- Interest expense on the Kasten debenture in 2021, while the Corporation was related to Kasten, was $26,667 and was recorded in the consolidated statement of loss and comprehensive loss.
- Convertible note payable #2 in the amount of $1,293,751 is owing to Kasten and was related by a common director until February 28, 2021. Interest expense in 2021, while the Corporation was related to Kasten, was $17,170 and was recorded in the consolidated statements of loss and comprehensive loss.
- The Corporation recovered rent and other office expenses from corporations related by a common director in 2022 of $14,136 (2021 - $12,834).

Off Balance Sheet Arrangements

The Corporation had no guarantees or off-balance sheet arrangements except for certain lease agreements that were entered into in the normal course of operations. All leases are treated as operating leases whereby the lease payments are included in operating expenses or general and administrative expenses depending on the nature of the lease. No asset or liability value has been assigned to these leases on the balance sheet as at December 31, 2022. The total future obligation from these operating leases is described above in the section "Material Contracts, Commitments and Contingencies".

Accounting Standards Adopted in 2021 and Future Amendments

Future accounting standards and pronouncements

Onerous Contracts—Cost of Fulfilling a Contract (Amendments to IAS 37)

The amendments to IAS 37 specify which costs an entity includes in determining the cost of fulfilling a contract for the purpose of assessing whether the contract is onerous. Costs that relate directly to a contract can either be incremental costs of fulfilling that contract (examples would be direct labour, materials) or an allocation of other costs that relate directly to fulfilling contracts (an example would be the allocation of the depreciation charge for an item of property, plant and equipment used in fulfilling the contract).

Classification of Liabilities as Current or Non-current (Amendments to IAS 1)

The amendments to IAS1 provide a more general approach to the classification of liabilities based on the contractual arrangements in place at the reporting date.

These amendments are effective for reporting periods beginning on or after January 1, 2023.

Business Risks and Uncertainties

The Corporation's business is subject to risks inherent in oil and natural gas exploration and development operations. In addition, there are risks associated with the Corporation's current and future operations in the jurisdictions in which it operates. The Corporation has identified certain risks pertinent to its business including: exploration and reserve risks, drilling and operating risks, changes to regulatory requirements, costs and availability of materials and services, capital markets and the requirement for additional capital, loss of or changes to joint venture or related agreements, economic and sovereign risks, reliance on joint venture partners, market risk, volatility of future oil and natural gas prices and foreign currency risk. Management seeks to reduce such risks by employing professionals and utilizing consultants and contractors to conduct the business of the Corporation in strict compliance with corporate governance, operating, safety, health and environmental requirements and best practices.

Further, in this regard, management also places great emphasis on fostering and maintaining a strong working relationship with its partners, CLFN and its wholly-owned energy company, with respect to the on-going development of CLFN lands.

Limited Operating and Earnings History

The Corporation has no earnings history. The Corporation's future business plans may require significant expenditure, particularly capital expenditure, in the establishment of Canadian oil and gas operations. Any future profitability from the Corporation's business will be dependent upon the successful acquisition of new lands, and there can be no assurance that the Corporation will achieve profitability in the future.

Investment Risks

The timing and extent of revenues is variable and uncertain and accordingly the Corporation is unable to predict when, if at all, profitability will be achieved. An investment in the Common Shares is highly speculative and should only be made by persons who can afford a significant or total loss of their investment.

History of Losses

Historically the Corporation has incurred losses from operations. As at December 31, 2022, the Corporation had a cumulative deficit of $131,259,646. There can be no assurance that the Corporation will achieve profitability in the future. In addition, should the Corporation be unable to continue as a going concern, realization of assets and settlement of liabilities other than in the normal course of business may be at amounts significantly different from those in the financial statements.

Cash Flow Used in Operations

In 2022 the Corporation used cash from operations of $168,453 (2021 - $337,419). The Corporation generally has a history of negative cash flow from operations, that together with the Corporation's inability to generate positive operating cash inflow, could have a material adverse impact on its business, operations and prospects in the future. There is still uncertainty at this time what the long term effects of COVID–19 will be on future operations of the Corporation.

Competition

Oil and gas exploration is intensely competitive in all phases and involves a high degree of risk. The Corporation competes with numerous other participants in the search for, and the acquisition of, oil and natural gas properties. The Corporation's competitors include oil and natural gas companies that have substantially greater financial resources, staff and facilities than those of the Corporation. The Corporation's ability to add reserves in the future will depend not only on its ability to explore and develop properties, but also on its ability to select and acquire suitable producing properties or prospects for exploratory drilling. Competitive factors in the distribution and marketing of oil and natural gas include price and methods and reliability of delivery. Competition may also be presented by alternate fuel sources.

Operational Dependence

In the future, the Corporation may enter into operations in which it is not the operator or which may be dependent or effected by the activities or conduct of third parties. As such, the Corporation may have limited ability to exercise influence or control over the operation of such assets or their associated costs, which could adversely affect the Corporation's financial performance. Therefore, the Corporation's return on such operations will depend upon a number of factors that may be outside of the Corporation's control, including the timing and amount of capital expenditures, an operator's or other third party's expertise and financial resources, the approval of other participants, the selection of technology and risk management practices.

Reliance on Key Personnel

The Corporation's success will depend in large measure on the performance of the Board and other key personnel. The loss of services of such individuals could have a material adverse effect on the Corporation. The Corporation does not have key person insurance in effect for management. The contributions of these individuals to the immediate operations of the Corporation are likely to be of central importance. In addition, there can be no assurance that the Corporation will be able to continue to attract and retain all personnel necessary for the development and operation of its business. Investors must rely upon the ability, expertise, judgment, discretion, integrity and good faith of the management of the Corporation.

Assessments of Value of Acquisitions

Acquisitions of oil and natural gas issuers and oil and natural gas assets are typically based on engineering and economic assessments made by independent engineers and the Corporation's own assessments. These assessments will include a series of assumptions regarding such factors as recoverability and marketability of oil and gas, future prices of oil and gas and operating costs, future capital expenditures and royalties and other government levies which will be imposed over the producing life of the reserves. Many of these factors are subject to change and are beyond the Corporation's control. In particular, the prices of, and markets for, oil and natural gas products may change from those anticipated at the time of making such assessment. In addition, all such assessments involve a measure of geological and engineering uncertainty which could result in lower than anticipated production and reserves. Initial assessments of acquisitions may be based on reports by a firm of independent engineers that are not the same as the firm that the Corporation may use for its year-end reserve evaluations. Because each of these firms may have different evaluation methods and approaches, these initial assessments may differ significantly from the assessments of the firm used by the Corporation. Any such instance may offset the return on and value of the Common Shares.

Estimate of Fair Market Value

There are numerous uncertainties inherent in an estimate of fair market value including many factors beyond the Corporation's control. The valuations herein represent estimates only. In general, estimates are based upon a number of variable factors and assumptions, such as engineering and geophysical information pertaining to hydrocarbon potential, current material contracts of the Corporation, production history of competitors on similar land positions, access to lands, availability, timing and amount of capital expenditures, marketability of oil and natural gas, royalty rates, the assumed effects of regulation by governmental agencies, and future operating costs, all of which may vary from actual results. All such estimates are to some degree speculative and are only attempts to define the degree of speculation involved.

Insurance

Oil and natural gas exploration, development and production operations are subject to all the risks and hazards typically associated with such operations, including hazards such as fire, explosion, blowouts, cratering, sour gas releases and spills, each of which could result in substantial damage to oil and natural gas wells, production facilities, other property and the environment or in personal injury. However, such insurance has limitations on liability that may not be sufficient to cover the full extent of such liabilities. In addition, such risks may not be insurable in all circumstances or, in certain circumstances, the Corporation may elect not to obtain insurance to deal with specific risks due to the high premiums associated with such insurance or other reasons. The payment of any such uninsured liabilities would reduce the funds available to the Corporation. The occurrence of a significant event that the Corporation is not fully insured against, or the insolvency of the insurer of such event, could have a material adverse effect on the Corporation's financial position, results of operations or prospects. The Corporation believes it is adequately insured for normal risks.

Corporate Matters

The Corporation does not anticipate the payment of any dividends on the Common Shares for the foreseeable future. Certain directors and officers of the Corporation are also directors and officers of other oil and natural gas companies involved in natural resource exploration and development, and conflicts of interest may arise between their duties as directors and officers of the Corporation and as directors and officers of such other companies. Such conflicts must be disclosed in accordance with and are subject to such other procedures and remedies as applicable under, the Alberta Business Corporations Act.

Title to Properties

Title to oil and natural gas interests is often not capable of conclusive determination without incurring substantial expense. Although title reviews will be done according to industry standards prior to the purchase of most oil and natural gas producing properties or the commencement of drilling wells, such reviews do not guarantee or certify that an unforeseen defect in the chain of title will not arise to defeat the claim of the Corporation. To the extent title defects do exist, it is possible the Corporation may lose all or a portion of its right, title, estate and interest in and to the properties to which the title relates.

Additional Funding Requirements

The Corporation will require additional financing from time to time in order to carry out oil and natural gas exploration and development activities. Failure to obtain such financing on a timely basis could cause the Corporation to have limited ability to expend the capital necessary to undertake or complete future exploration programs, forfeit its interest in certain properties, miss certain acquisition opportunities and reduce or terminate its operations. There can be no assurance that debt or equity financing or cash generated by operations will be available or sufficient to meet these requirements or for other corporate purposes or, if debt or equity financing is available, that it will be on terms acceptable to the Corporation. Moreover, future activities may require the Corporation to alter its capitalization significantly.

Dilution

The Corporation may make future acquisitions or enter into financing or other transactions involving the issuance of securities of the Corporation, which may be dilutive to existing shareholders.

Environmental

All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of federal, provincial and local laws and regulations. Environmental legislation provides for, among other things, restrictions and prohibitions on spills, releases or emissions of various substances produced in association with oil and natural gas operations. The legislation also requires that wells and facility sites be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. Compliance with such legislation can require significant expenditures and a breach may result in the imposition of fines and penalties, some of which may be material.

Environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liability and the potential for increased capital expenditures and operating costs. The discharge of oil, natural gas or other pollutants into the air, soil or water may give rise to liabilities to governments and third parties and may require the Corporation to incur costs to remedy such discharge.

Statutory provisions require petroleum tenement lands to be protected and rehabilitated to ensure that environmental damage is avoidable or minimal where authorized. These provisions may require approvals and consents to be obtained before certain lands may be accessed and explored. In addition, each state and territory government may impose a wide range of obligations on tenement holders to ensure that petroleum operations comply with various environmental standards and requirements.

No assurance can be given that environmental laws will not result in a curtailment of future production (if any) or a material increase in the costs of production, development or exploration activities or otherwise adversely affect the Corporation's financial condition, results of operations or prospects.

Changes in Legislation

Legislation and regulations continue to be introduced by government and government agencies concerning the security of industrial facilities, including oil and natural gas facilities. The Corporation's operations may be subject to such laws and regulations. Presently, it is not possible to accurately estimate the costs the Corporation could incur to comply with any such laws or regulations, but such expenditures could be substantial.

Income Taxes

The Corporation will file all required income tax returns and believes that it will be in full compliance with the provisions of the *Income Tax Act* (Canada) and all other applicable tax legislation. However, such returns are subject to reassessment by applicable taxation authorities. In the event of a successful reassessment of the Corporation, whether by re-characterization of exploration and development expenditures or otherwise, such reassessment may have an impact on current and future taxes payable.

Integrity of Disclosure

The Corporation's management maintains appropriate information systems, procedures and controls to ensure that information used internally and disclosed externally is complete and reliable.

The Board is responsible for ensuring that management fulfills its responsibilities. The Audit Committee fulfills its role of ensuring the integrity of the reported information through its review of the audited consolidated financial statements. The Board approves the annual audited consolidated financial statements and MD&A on the recommendation of the Audit Committee.

The Corporation has approved a series of policy papers that include Code of Business Conduct and Ethics, Whistle Blower Policy and Procedures, Insider Trading and Reporting Guidelines, Disclosure Policy and Board Control System. Terms of References define Audit Committee and Compensation and Governance Committees. The Corporation has a defined Board Mandate.

Additional Information

Additional information on the Corporation can be accessed at www.sedar.com or from the Corporation's website at www.petrofrontier.com or by contacting the Corporation at PetroFrontier Corp., Suite 700, 903 - 8th Avenue S.W. Calgary, Alberta, Canada T2P 0P7.

Directors

Michael Hibberd
Chairman of the
Board of Directors
Calgary, Alberta

Kenneth L. DeWyn
Educator
Calgary, Alberta

Kelly Kimbley
President
Calgary, Alberta

Officers

Kelly Kimbley
CEO and President

Jana Lillies
Chief Financial Officer

Ulrich Wirth
Vice-President
Exploration

Omar El-Hajjar
Vice-President
Operations

David Orr
Vice-President
Business Development

Corporate Head Office

700, 903 – 8 Avenue S.W.
Calgary, Alberta T2R 0P7

Trustee and Transfer Agent

Computershare Trust Company

Solicitors

DS Lawyers

Auditors

MNP LLP