WestFire ENERGY LTD

ANNUAL INFORMATION FORM

FOR THE YEAR ENDED

DECEMBER 31, 2011

March 26, 2012

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SCHEDULES

ABBREVIATIONS

Oil and Natural Gas Liquids		Natural Gas	
Bbl	barrel	Mcf	thousand cubic feet
Bbls	barrels	MMcf	million cubic feet
Mbbls	thousand barrels	Mcf/d	thousand cubic feet per day
MMbbls	million barrels	MMcf/d	million cubic feet per day
Mstb	1,000 stock tank barrels	Mmbtu	million British Thermal Units
Bbls/d	barrels per day	Bcf	billion cubic feet
BOPD	barrels of oil per day	GJ	Gigajoule
NGLs	natural gas liquids		
STB	standard tank barrels		

Other

AECO	Alberta Energy Company interconnect with Nova system, the Canadian benchmark for natural gas pricing.
API	American Petroleum Institute
°API	an indication of the specific gravity of crude oil measured on the API gravity scale. Liquid petroleum with a specified gravity of 28° API is generally referred to as light crude oil.
BOE	barrel of oil equivalent of natural gas and crude oil on the basis of 1 BOE for 6 Mcf of natural gas (this conversion factor is an industry accepted norm and is not based on either energy content or current prices). **Disclosure provided herein in respect of BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 Mcf:1 Bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Given that the value ratio based on the current price of crude oil as compared to natural gas is significantly different from the energy equivalency of 6:1, utilizing a conversion on a 6:1 basis may be misleading as an indication of value.**
BOE/d	barrel of oil equivalent per day
m3	cubic metres
MBOE	1,000 barrels of oil equivalent
$M or $000s	thousands of dollars
MM	Million
WTI	West Texas Intermediate, the reference price paid in U.S. dollars at Cushing, Oklahoma for crude oil of standard grade

Where any disclosure of reserves data is made in this Annual Information Form (or the Schedules hereto) that does not reflect all reserves of WestFire, the reader should note that the estimates of reserves and future net revenue for individual properties or groups of properties may not reflect the same confidence level as estimates of the reserves and future net revenue for all properties, due to the effects of aggregation.

CONVERSIONS

To Convert From	To	Multiply By
Mcf	Cubic metres	28.174
Cubic metres	Cubic feet	35.494
Bbls	Cubic metres	0.159
Cubic metres	Bbls oil	6.290
Feet	Metres	0.305
Metres	Feet	3.281
Miles	Kilometres	1.609
Kilometres	Miles	0.621
Acres	Hectares	0.405
Hectares	Acres	2.471

CONVENTIONS

A reference in this Annual Information Form to "**WestFire**", the "**Company**" or the "**Corporation**" means WestFire Energy Ltd. Certain other terms used herein but not defined herein are defined in National Instrument 51-101 *Standards of Disclosure for Oil and Gas Activities* ("**NI 51-101**") and in the Canadian Oil and Gas Evaluation ("**COGE**") Handbook Volume I. Unless otherwise specified, information in this Annual Information Form is as at the end of the Corporation's most recently completed financial year, being December 31, 2011. All dollar amounts herein are in Canadian dollars, unless otherwise stated.

FORWARD-LOOKING STATEMENTS

Certain statements contained herein including, without limitation, financial and business prospects and financial outlook, the potential results of the strategic alternative review process and enhancement of shareholder value; disclosure intentions with respect to the strategic alternative review process; reserve and production estimates, drilling and re-completion plans, timing of drilling, re-completion and tie in of wells, tax horizon, timing of development of undeveloped reserves, productive capacity of wells and productive capacity of wells and capital expenditures and the timing thereof may be forward looking statements. Words such as "may", "will", "should", "could", "anticipate", "believe", "expect", "intend", "plan", "potential", "continue" and similar expressions may be used to identify these forward looking statements. These statements reflect management's current beliefs and are based on information currently available to management. Forward looking statements involve significant risk and uncertainties. A number of factors could cause actual results to differ materially from the results discussed in the forward looking statements including, but not limited to, risks associated with oil and gas exploration, development, exploitation, production, marketing and transportation, loss of markets, volatility of commodity prices, currency fluctuations, imprecision of reserve estimates, environmental risks, competition from other producers, inability to retain drilling rigs and other services, incorrect assessment of the value of acquisitions, failure to realize the anticipated benefits of acquisitions, delays resulting from or inability to obtain required regulatory approvals and ability to access sufficient capital from internal and external sources and the risk factors outlined under "Risk Factors" and elsewhere herein. The recovery and reserve estimates of WestFire's reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. As a consequence, actual results may differ materially from those anticipated in the forward-looking statements. Readers are cautioned that the foregoing list of factors is not exhausted. Additional information on these and other factors that could affect WestFire's operations and financial results are included in reports on file with Canadian securities regulatory authorities and may be accessed through the SEDAR website (www.sedar.com) and at WestFire's website (www.WestFireenergy.com). **Although the forward looking statements contained herein are based upon what management believes to be reasonable assumptions, management cannot assure that actual results will be consistent with these forward looking statements. Investors should not place undue reliance on forward looking statements. These forward looking statements are made as of the date hereof and the Corporation assumes no obligation to update or review them to reflect new events or circumstances except as expressly required by applicable securities laws**.

Forward looking statements and other information contained herein concerning the oil and gas industry and the Corporation's general expectations concerning this industry are based on estimates prepared by management using data from publicly available industry sources as well as from reserve reports, market research and industry analysis and on assumptions based on data and knowledge of this industry which the Corporation believes to be reasonable. However, this data is inherently imprecise, although generally indicative of relative market positions, market shares and performance characteristics. While the Corporation is not aware of any misstatements regarding any industry data presented herein, the industry involves risks and uncertainties and is subject to change based on various factors.

CORPORATE STRUCTURE

Name, Address and Incorporation

WestFire Energy Ltd.

Head Office:	Registered Office:
Suite 1400, 440-2nd Avenue S.W.	2400, 525 – 8th Avenue S.W.
Calgary, Alberta T2P 5E9	Calgary, Alberta T2P 1G1

WestFire was amalgamated under the *Business Corporations Act* (Alberta) (the "**ABCA**") on June 30, 2011.

Intercorporate Relationships

WestFire has no subsidiaries.

GENERAL DEVELOPMENT OF THE BUSINESS

Three Year History

The general development of WestFire's business over the last three completed financial years that include events, such as acquisitions or dispositions, or conditions that have had an influence on that development, are described below.

On June 18, 2009, WestFire acquired certain oil and gas assets of Ramparts Energy Ltd. from 1218995 Alberta Ltd. for $7,946,457 in exchange for 447,059 Common Shares valued at $4.25 per share. The majority of these oil and gas assets acquired by WestFire are located in the Redwater area of Alberta.

On June 30, 2009, WestFire completed: a non-brokered private placement of 5,267,480 Common Shares at a price of $3.50 per share; and a non-brokered private placement of 362,809 Common Shares issued on a "flow through" basis for $4.25 per share for aggregate gross proceeds of $19,978,118.

On October 30, 2009, WestFire entered into an asset purchase and sale agreement with a Court-appointed receiver whereby WestFire agreed to acquire certain oil and gas properties of Action Energy Inc. for $30.0 million. The acquisition closed on December 18, 2009 and added approximately 625 BOE/d of production.

On November 2, 2009, WestFire entered into an arrangement agreement with Exceed Energy Inc. ("**Exceed**") whereby WestFire agreed to acquire all of the outstanding shares of Exceed. As part of the transaction, Exceed completed a $45,040,000 bought deal private placement common share financing. The common shares of Exceed and the shares issued pursuant to the private placement were subsequently exchanged, pursuant to this transaction, for 645,229 Common Shares. The Exceed shares were de-listed from the TSX Venture Exchange on December 23, 2009 and the Common Shares were listed on the Toronto Stock Exchange under the symbol "WFE" on December 24, 2009.

On April 30, 2010, WestFire completed a strategic Viking oil acquisition in the Provost area of Alberta for approximately $7.5 million in cash, prior to any working capital adjustments. This acquisition added an additional 85 BOE/d of production.

On March 9, 2011, WestFire completed a public offering of 4,862,000 Common Shares at a price of $9.05 for gross proceeds of $44,001,100.

On June 30, 2011, WestFire acquired all of the outstanding shares of Orion Oil & Gas Corporation ("**Orion**") in consideration for the issuance of approximately 22,527,938 Common Shares and 15,613,689 non-listed, non-voting convertible shares of ("**Non-Voting Convertible Shares**") WestFire (the "**Orion Acquisition**").

On December 9, 2011, WestFire completed a strategic Viking oil acquisition in the Redwater area of Alberta, for approximately $40.3 million in cash, prior to any working capital adjustments. This acquisition added an additional 600 BOE/d of production.

Strategic Alternative Review Process

On December 19, 2011 the Board of Directors initiated a process to identify, examine and consider a range of strategic alternatives available to the Company with a view to enhancing shareholder value.

Strategic alternatives may include, but are not limited to, a sale of all or a material portion of the assets of WestFire, either in one transaction or in a series of transactions, the outright sale of the Company, or merger or other transaction involving WestFire and a third party. For the purposes of considering strategic alternatives, WestFire has established a special committee consisting of independent directors, John Brussa (Chair), Christopher Fong and Roger Thomas and the Company's Executive Chairman, Ed Chwyl (being a non-voting member) to oversee the process. WestFire has engaged Cormark Securities Inc. as its financial advisor in connection with the process.

The Board of Directors has determined that the Company's shares trade at a significant discount to the value of its underlying assets, especially given its high quality, low cost, operated asset base, which generates operating netbacks that are top quartile in industry, its strong balance sheet, its fully funded 2012 capital expenditure program, its large undeveloped land position and its multi-year drilling inventory with over 1,000 net prospective locations in its three core Viking light oil resource play project areas at Redwater and Provost, Alberta and Plato, West Central Saskatchewan. WestFire's Viking development at Redwater and Provost continues to exceed the Company's expectations and WestFire continues to be encouraged with recent results at Plato.

This strategic alternative review process has not been initiated as a result of receiving any offer and there are no assurances that a transaction will be undertaken. It is WestFire's current intention not to disclose developments with respect to the process unless and until the Board of Directors has approved a specific transaction or otherwise determines that disclosure is necessary. The Company cautions that there are no assurances or guarantees that the process will result in a transaction or, if a transaction is undertaken, the terms or timing of such transaction. The Company has not established a definitive schedule to complete its identification, examination and consideration of strategic alternatives.

Significant Acquisitions

Other than the Orion Acquisition described under the heading "General Development of the Business – Three Year History", WestFire did not complete any significant acquisitions during its most recently completed financial year for which disclosure is required under Part 8 of National Instrument 51-102 – Continuous Disclosure Obligations. WestFire has filed a Form 51-102F4 in respect of the Orion Acquisition.

DESCRIPTION OF THE BUSINESS

General

The Corporation is engaged in the acquisition, development and production of crude oil and natural gas in Western Canada.

WestFire's strategy for growth includes an active acquisition, exploitation and development program.

For the majority of its core area projects, WestFire strives to maintain 100% ownership in order to control operatorship, infrastructure and timing of capital projects and spending. Occasionally, WestFire will attempt to spread risk and build alliances by seeking joint venture partners, where appropriate. The partners are expected to be of similar size, have similar acquisition and development strategies and have the ability to offer reciprocal opportunities.

Specialized Skill and Knowledge

Drawing on significant experience in the oil and gas business, WestFire's management team has a demonstrated track record of bringing together all of the key components to a successful acquisition and development company: strong technical skills; expertise in planning and financial controls; ability to execute on business development opportunities; capital markets expertise; and an entrepreneurial spirit that allows WestFire to effectively identify, evaluate and execute on value added initiatives.

Competitive Conditions

Companies operating in the petroleum industry must manage risks which are beyond the direct control of company personnel. Among these risks are those associated with exploration, environmental damage, access to third party pipelines and facilities, commodity prices, foreign exchange rates and interest rates.

The oil and natural gas industry is intensely competitive and WestFire is required to compete with a substantial number of other entities which may have greater technical or financial resources. With the maturing nature of the Western Canadian Sedimentary Basin, the access to new prospects is becoming more and more competitive and complex.

WestFire will attempt to enhance its competitive position by operating in areas where its technical personnel are able to reduce some of the risks associated with exploration, production and marketing because they are familiar with the areas of operation. Management believes that WestFire will be able to explore and develop new production and reserves with the objective of increasing its cash flow and reserve base. See "*Risk Factors – Competition*".

Cycles

The Corporation's business is generally cyclical. The exploration and development of oil and natural gas reserves is dependent on access to areas where drilling is to be conducted. Seasonal weather variation, including freeze up and break up affect access in certain circumstances. See "*Risk Factors – Seasonality*".

Environmental Protection

The oil and natural gas industry is currently subject to environmental regulations pursuant to a variety of provincial and federal legislation. Compliance with such legislation can require significant expenditures or result in operational restrictions. Breach of such requirements may result in suspension or revocation of necessary licenses and authorizations, civil liability for pollution damage and the imposition of material fines and penalties, all of which might have a significant negative impact on earnings and overall competitiveness. See "*Industry Conditions – Environmental Regulation*" and "*Risk Factors – Environmental*".

Employees

As at December 31, 2011, WestFire had 49 full time employees and 11 consultants, all of whom were located at its office in Calgary. In addition, WestFire had 21 full time employees and 22 contract operators in various field locations.

Reorganizations

Other than disclosed herein under "*General Development of the Business – Three Year History*", WestFire has not completed any material reorganization within the three most recently completed financial years or completed during the current financial year. No material reorganization is currently proposed for the current financial year. See "*General Development of the Business – Three Year History*".

Environmental, Health and Safety Policies

Environmental protection and employee health and safety are core values recognized and supported by the Corporation. The Corporation actively supports these areas by integrating the essential principles and practices through its environmental management systems and employee occupational health and safety programs. The Corporation ensures policies and procedures are fully integrated with and within all operating units by advising and educating employees, suppliers and contractors in the safe use, transportation, storage and disposal of products and materials. The Corporation promotes and enhances safety and environmental awareness and protection through the implementation and communication of the Corporation's environmental management and employee occupational health and safety programs policies and procedures. Effective committee structures are established in the Corporation's operations to allow for employee participation and development of Corporate policies and programs which provide employees with job orientation, training, instruction and supervision necessary to assist them in conducting their activities in an environmentally responsible and safe manner.

The Corporation develops emergency response teams and preparedness plans in conjunction with local authorities, emergency services and the communities it operates in, in order to ensure prompt response to an environmental incident should it arise. Environmental assessments are undertaken for new projects or when acquiring new properties or facilities to identify, assess and minimize environmental risks and operational exposures. The Corporation conducts audits of operations to confirm compliance with internal standards and to stimulate improvement in practices where needed. Accurate documentation is maintained to support internal accountability and measure operational performance against recognized industry indicators to ensure the objectives of the policies and programs are achieved.

The Corporation also faces environmental, health and safety risks in the normal course of its operations due to the handling and storage of hazardous substances. The Corporation's environmental and occupational health and safety management systems are designed to identify, prevent and control such risks in the Corporation's business and ensure immediate action is taken to mitigate the extent of any environmental, health or safety impacts from such operations. A key aspect of these systems is the performance of annual environmental and occupational health and safety audits.

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

Date of Statement

The statement of reserves data and other oil and gas information set forth below (the "**Statement**") is dated March 26, 2012. The effective date of the Statement is December 31, 2011 and the preparation date of the Statement is March 13, 2012.

Disclosure of Reserves Data

The reserves data set forth below (the "**Reserves Data**") is based upon an evaluation by GLJ Petroleum Consultants Ltd. ("**GLJ**") with an effective date of December 31, 2011 contained in GLJ's report dated March 13, 2012 evaluating the crude oil, natural gas liquids and natural gas reserves of the Corporation as at December 31, 2011 (the "**GLJ Report**"). The Reserves Data summarizes the crude oil, natural gas liquids and natural gas reserves of the Corporation and the net present values of future net revenue for these reserves using forecast prices and costs. The Reserves Data conforms with the standards required by NI 51-101. The Corporation engaged GLJ to provide an evaluation of proved and proved plus probable reserves and no attempt was made to evaluate possible reserves.

All of the Corporation's reserves are in Canada and, specifically, in the provinces of Alberta, Saskatchewan and British Columbia.

The Report of Management and Directors on Oil and Gas Disclosure in Form 51-101F3 and the Report on Reserves Data by Independent Qualified Reserves Evaluator in Form 51-101F2 are attached as Schedules "A" and "B", respectively.

It should not be assumed that the estimates of future net revenues presented in the tables below represent the fair market value of the reserves. There is no assurance that the forecast prices and costs assumptions will be attained and variances could be material. The recovery and reserve estimates of the Corporation's crude oil, natural gas liquids and natural gas reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual crude oil, natural gas and natural gas liquid reserves may be greater than or less than the estimates provided herein.

Reserves Data (Forecast Prices and Costs)

SUMMARY OF OIL AND GAS RESERVES
AND NET PRESENT VALUES OF FUTURE NET REVENUE
AS OF DECEMBER 31, 2011
FORECAST PRICES AND COSTS

	LIGHT AND MEDIUM OIL		HEAVY OIL		CONVENTIONAL NATURAL GAS		NATURAL GAS LIQUIDS	
RESERVES CATEGORY	**Gross (Mbbl)**	**Net (Mbbl)**	**Gross (Mbbl)**	**Net (Mbbl)**	**Gross (MMcf)**	**Net (MMcf)**	**Gross (Mbbl)**	**Net (Mbbl)**
PROVED								
Developed Producing	4,480	3,961	525	483	40,018	34,899	2,718	1,800
Developed Non-Producing	236	200	62	56	7,333	6,501	548	369
Undeveloped	7,962	6,968	155	138	16,584	15,062	1,558	1,156
TOTAL PROVED	12,678	11,129	741	677	63,934	56,462	4,824	3,325
PROBABLE								
TOTAL PROVED PLUS	8,301	7,134	397	349	24,496	21,321	1,604	1,042
PROBABLE	20,979	18,263	1,138	1,026	88,430	77,783	6,428	4,366

NET PRESENT VALUES OF FUTURE NET REVENUE

	BEFORE INCOME TAXES DISCOUNTED AT (%/year)					AFTER INCOME TAXES DISCOUNTED AT (%/year) [(1)]				
RESERVES CATEGORY	**0% (M$)**	**5% (M$)**	**10% (M$)**	**15% (M$)**	**20% (M$)**	**0% (M$)**	**5% (M$)**	**10% (M$)**	**15% (M$)**	**20% (M$)**
PROVED										
Producing	454,728	378,456	325,819	287,431	258,219	454,728	378,456	325,819	287,431	258,219
Developed Non-Producing	66,433	47,554	36,436	29,243	24,249	66,433	47,554	36,436	29,243	24,249
Undeveloped	398,278	270,983	189,276	134,312	95,904	328,557	222,923	154,813	108,786	76,483
TOTAL PROVED	919,440	696,993	551,530	450,986	378,372	849,719	648,933	517,068	425,460	358,951
TOTAL PROBABLE	600,031	382,651	264,175	193,224	147,537	451,931	284,973	194,594	140,809	106,405
TOTAL PROVED PLUS PROBABLE	1,519,471	1,079,644	815,705	644,210	525,909	1,301,650	933,905	711,662	566,269	465,357

Note:

(1) The after-tax net present value of the WestFire's oil and gas properties reflects the tax burden on the properties on a stand-alone basis and without the Corporation's tax pools. It does not consider the corporate tax situation, or tax planning. It does not provide an estimate of the value at the level of the corporation, which may be significantly different. WestFire's financial statements and the management's discussion and analysis should be consulted for information at the level of the corporation.

TOTAL FUTURE NET REVENUE (UNDISCOUNTED) AS OF DECEMBER 31, 2011 FORECAST PRICES AND COSTS

RESERVES CATEGORY	REVENUE (M$)	ROYALTIES (M$)	OPERATING COSTS (M$)	DEVELOPMENT COSTS (M$)	ABANDONMENT COSTS (M$)	FUTURE NET REVENUE BEFORE INCOME TAXES (M$)	INCOME TAXES (M$)	FUTURE NET REVENUE AFTER INCOME TAXES (M$)[1]
Proved Reserves	2,188,548	334,325	564,994	342,592	27,197	919,440	69,721	849,719
Proved Plus Probable Reserves	3,452,996	543,199	880,530	476,664	33,132	1,519,471	217,821	1,301,650

Note:

(1) The after-tax net present value of the WestFire's oil and gas properties reflects the tax burden on the properties on a stand-alone basis and without the Corporation's tax pools. It does not consider the corporate tax situation, or tax planning. It does not provide an estimate of the value at the level of the corporation, which may be significantly different. WestFire's financial statements and the management's discussion and analysis should be consulted for information at the level of the corporation.

NET PRESENT VALUE OF FUTURE NET REVENUE BY PRODUCTION GROUP AS OF DECEMBER 31, 2011 FORECAST PRICES AND COSTS

RESERVES CATEGORY	PRODUCTION GROUP	FUTURE NET REVENUE BEFORE INCOME TAXES (discounted at 10%/year)[1][2][3][4] (M$)	($/Boe)
Proved Reserves	Light and Medium Crude Oil [5]	328,027	26.76
	Heavy Oil [5]	17,461	25.37
	Conventional Natural Gas [6]	206,043	17.77
	Total	551,530	22.47
Proved Plus Probable Reserves	Light and Medium Crude Oil [5]	530,718	26.32
	Heavy Oil [5]	25,449	24.39
	Conventional Natural Gas [6]	259,538	16.84
	Total	815,705	22.28

Notes:

(1) Other Company revenue and costs not related to a specific production group have been allocated proportionately to the above noted production groups. Unit values are based on Company Net Reserves.

(2) Estimated future abandonment costs related to a property have been taken into account by GLJ in determining reserves that should be attributed to a property and, in determining the aggregate future net revenue therefrom, there was deducted the reasonable estimated future well abandonment costs. No allowance was made, however, for reclamation of well sites or the abandonment and reclamation of any facilities.

(3) The forecast price and cost assumptions assume the continuance of current laws and regulations.

(4) The extent and character of all factual data supplied to GLJ were accepted by GLJ as represented. No field inspection was conducted.

(5) Including solution gas and other by-products.

(6) Including by-products but excluding solution gas.

Pricing Assumptions

Forecast Prices Used in Estimates

Forecast prices and costs are those:

(a) generally acceptable as being a reasonable outlook of the future; and

(b) if and only to the extent that, there are fixed or presently determinable future prices or costs to which we are legally bound by a contractual or other obligation to supply a physical product, including those for an extension period of a contract that is likely to be extended, those prices or costs rather than the prices and costs referred to in paragraph (a).

The forecast cost and price assumptions assume increases in wellhead selling prices and take into account inflation with respect to future operating and capital costs. Crude oil and natural gas benchmark reference pricing, inflation and exchange rates utilized by GLJ in the GLJ Report were GLJ's forecasts as follows:

SUMMARY OF PRICING AND INFLATION RATE ASSUMPTIONS
FORECAST PRICES AND COSTS

	OIL			**CONVENTIONAL NATURAL GAS**					
Year	**WTI at Cushing Oklahoma ($US/Bbl)**	**Edmonton City Gate ($Cdn/Bbl)**	**Heavy Crude (12 API) at Hardisty**	**Natural Gas AECO Average Price ($Cdn/ Mcf)**	**Pentanes Plus Edmonton Par ($Cdn/ Bbl)**	**Butanes Edmonton Par ($Cdn/Bbl)**	**Propane Edmonton Par ($Cdn/ Bbl)**	**Inflation Rates(1) %/Year**	**Exchange Rate(2) ($US/ $Cdn)**
Forecast									
2012	97.00	97.96	72.37	3.49	107.76	76.41	58.78	2.0	0.980
2013	100.00	101.02	73.60	4.13	108.09	78.80	60.61	2.0	0.980
2014	100.00	101.02	74.51	4.59	105.06	78.80	60.61	2.0	0.980
2015	100.00	101.02	74.51	5.05	105.06	78.80	60.61	2.0	0.980
2016	100.00	101.02	74.51	5.51	105.06	78.80	60.61	2.0	0.980
2017	100.00	101.02	74.51	5.97	105.06	78.80	60.61	2.0	0.980
2018	101.35	102.40	75.54	6.21	106.49	79.87	61.44	2.0	0.980
2019	103.38	104.47	77.09	6.33	108.65	81.49	62.68	2.0	0.980
2020	105.45	106.58	78.67	6.46	110.84	83.13	63.95	2.0	0.980
2021	107.56	108.73	80.28	6.58	113.08	84.81	65.24	2.0	0.980
2022+			Escalated oil, gas and product prices at 2% per year thereafter						

Notes:

(1) Inflation rates for forecasting prices and costs.
(2) Exchange rates used to generate the benchmark reference prices in this table.
(3) Weighted average historical prices realized by the Corporation for the year ended December 31, 2011, were $93.67/Bbl for light and medium crude oil, $66.85/Bbl for heavy oil, $3.85/Mcf for natural gas and $66.46/Bbl for natural gas liquids.

Reconciliation of Changes in Reserves

**RECONCILIATION OF GROSS RESERVES
BY PRINCIPAL PRODUCT TYPE
FORECAST PRICES AND COSTS**

	LIGHT AND MEDIUM OIL			HEAVY OIL			CONVENTIONAL NATURAL GAS			NGL		
FACTORS	**Proved (Mbbl)**	**Probable (Mbbl)**	**Proved Plus Probable (Mbbl)**	**Proved (Mbbl)**	**Probable (Mbbl)**	**Proved Plus Probable (Mbbl)**	**Proved (MMcf)**	**Probable (MMcf)**	**Proved Plus Probable (MMcf)**	**Proved (Mbbl)**	**Probable (Mbbl)**	**Proved Plus Probable (Mbbl)**
December 31, 2010	4,525	3,965	8,490	1,039	573	1,612	14,656	8,429	23,085	178	112	290
Discoveries	20	(20)	0	80	17	97	8	(8)	0	0	(0)	0
Extensions	3,432	1,012	4,443	30	45	75	1,053	875	1,928	6	12	17
Infill Drilling	1,346	224	1,569	0	0	0	2,219	842	3,061	228	97	325
Improved Recovery	0	0	0	0	0	0	0	0	0	0	0	0
Technical Revisions	224	220	444	(233)	(203)	(437)	(1,477)	(1,249)	(2,726)	63	(1)	62
Acquisitions	4,062	2,920	6,982	25	5	30	52,635	16,163	68,799	4,632	1,393	6,025
Dispositions	0	0	0	(1)	(35)	(36)	(21)	(5)	(26)	(1)	(0)	(1)
Economic Factors	(3)	(19)	(22)	(2)	(5)	(7)	(823)	(553)	(1,376)	(4)	(9)	(13)
Production	(927)	0	(927)	(196)	0	(196)	(4,315)	0	(4,315)	(278)	0	(278)
December 31, 2011	12,678	8,301	20,979	741	397	1,138	63,934	24,496	88,430	4,824	1,604	6,428

Note: The Corporation has no unconventional reserves (Bitumen, Synthetic Crude Oil, Natural Gas from Coal, etc.).

Note:

(1) Gross Reserves in the tables above are the Corporation's interest share before deduction of royalties and without including any royalty interests of the Corporation.

Additional Information Relating to Reserves Data

Undeveloped Reserves

The following tables set forth the proved undeveloped reserves and the probable undeveloped reserves, each by product type, attributed to that were first attributed in each of the most recent three financial years and, in the aggregate, before that time, based on forecast prices and costs. "First Attributed" refers to reserves first attributed at year-end of the corresponding fiscal year.

Proved Undeveloped Reserves

	Light and Medium Oil (Mbbl)		Heavy Oil (Mbbl)		Conventional Natural Gas (MMcf)		NGLs (Mbbl)	
Year	**First Attributed**	**Cumulative at Year End**	**First Attributed**	**Cumulative at Year End**	**First Attributed**	**Cumulative at Year End**	**First Attributed**	**Cumulative at Year End**
2009	912	952	170	170	444	461	0	0
2010	1,316	2,672	349	379	868	1,492	10	13
2011	6,293	7,962	30	155	15,690	16,584	1,551	1,558

Probable Undeveloped Reserves

	Light and Medium Oil (Mbbl)		Heavy Oil (Mbbl)		Conventional Natural Gas (MMcf)		NGLs (Mbbl)	
Year	**First Attributed**	**Cumulative at Year End**	**First Attributed**	**Cumulative at Year End**	**First Attributed**	**Cumulative at Year End**	**First Attributed**	**Cumulative at Year End**
2009	1,767	2,035	415	496	1,997	2,634	17	22
2010	2,634	3,480	124	361	1,129	2,075	19	28
2011	5,636	6,937	45	214	8,077	9,397	535	554

In general, once proved and/or probable undeveloped reserves are identified they are included in WestFire's development plans. Normally, the Corporation plans to develop its proved and probable undeveloped reserves within two years. A number of factors that could result in delayed or cancelled development are as follows:

- changing economic conditions (due to pricing, operating and capital expenditure fluctuations);
- changing technical conditions (production anomalies (such as water breakthrough, accelerated depletion));
- multi-zone developments (such as a prospective formation completion may be delayed until the initial completion is no longer economic);
- a larger development program may need to be spread out over several years to optimize capital allocation and facility utilization; and
- surface access issues (landowners, weather conditions, regulatory approvals).

Significant Factors or Uncertainties

The process of evaluating reserves is inherently complex. It requires significant judgments and decisions based on available geological, geophysical, engineering and economic data. These estimates may change substantially as additional data from ongoing development activities and production performance becomes available and as economic conditions impacting oil and gas prices and costs change. The reserve estimates contained herein are based on current production forecasts, prices and economic conditions and other factors and assumptions that may affect the reserve estimates and the present worth of the future net revenue therefrom. These factors and assumptions include, among others: (i) historical production in the area compared with production rates from analogous producing areas; (ii) initial production rates; (iii) production decline rates; (iv) ultimate recovery of reserves; (v) success of future development activities; (vi) marketability of production; (vii) effects of government regulations; and (viii) other government levies imposed over the life of the reserves.

As circumstances change and additional data becomes available, reserve estimates also change. Estimates are reviewed and revised, either upward or downward, as warranted by the new information. Revisions are often required due to changes in well performance, prices, economic conditions and government restrictions. Revisions to reserve estimates can arise from changes in year-end prices, reservoir performance and geologic conditions or production. These revisions can be either positive or negative.

The Corporation does not anticipate any unusually high development costs or operating costs, the need to build a major pipeline or other major facility before production of reserves can begin, or the need to enter into contractual obligations to produce and sell a significant portion of production at prices substantially below those which could be realized but for those contractual obligations.

Future Development Costs

The following table sets forth development costs deducted in the estimation of the Corporation's future net revenue attributable to the reserve categories noted below:

	Forecast Prices and Costs (M$)	
Year	Proved Reserves	Proved Plus Probable Reserves
2012	111,737	126,476
2013	111,973	151,725
2014	61,042	106,205
2015	48,076	71,157
2016	4,639	15,306
Thereafter	5,126	5,795
Total Undiscounted	342,592	476,664

The future development costs are capital expenditures required in the future for WestFire to convert proved undeveloped reserves and probable reserves to proved developed producing reserves. Future abandonment costs are also taken into account. The abandonment costs undiscounted are as follows: forecast prices and costs – proved reserves $27.2 million; and forecast prices and costs – proved plus probable reserves $33.1 million.

On an ongoing basis, WestFire will use internally generated cash flow from operations, debt and new equity issues and farm-outs or similar arrangements if available on favourable terms to finance its capital expenditure program. The cost of funding is not expected to have any material effect on disclosed reserves or future net revenue nor make the development of a property uneconomic for the Corporation.

Other Oil and Gas Information

Oil and Gas Properties

The following is a description of the Corporation's oil and natural gas properties, plants, facilities and installations as at December 31, 2011. Unless otherwise indicated, production stated is gross production to the Corporation and reflects average daily production during the month of December 2011. The reserve amounts are stated, before deduction of royalties, as at December 31, 2011 based on forecast costs and prices as evaluated in the GLJ Report. See "*Statement of Reserves Data and Other Oil and Gas Information*". **The estimates of reserves and future net revenue for individual properties may not reflect the same confidence level as estimates of reserves and future net revenue for all properties, due to the effects of aggregation.** Unless otherwise specified, gross and net acres and well count information are as at December 31, 2011.

Redwater – East Central Alberta

The Redwater area is located approximately 50 kilometres northeast of the city of Edmonton, Alberta. WestFire holds an average 87 percent working interest in 31,281 gross (27,069 net) undeveloped acres of land.

WestFire's development and production activities in the Redwater area are primarily directed toward light oil in the Viking formation with lesser emphasis on the Ellerslie light oil play. The lands in the Redwater area were obtained through four strategic acquisitions; Racing (September, 2008), assets from a court-appointed Receiver (May, 2009), Orion (July, 2011) and assets from a major independent (December, 2011) and through participation at select Crown land sales.

GLJ assigned 8,787 MBOE of proved reserves and 13,996 MBOE of proved plus probable reserves to the Redwater area effective December 31, 2011. During 2011, the Redwater area provided WestFire with average production of 2,415 BOE/d (including 1,632 Mcf/d gas) from 377 gross (351.7 net) wells. As at December 31, 2011, substantially all of WestFire's production in the Redwater area is operated by WestFire. WestFire transports and processes substantially all of its own production in the Redwater area.

During 2011, WestFire drilled 51 gross (50 net) Viking horizontal light oil wells at Redwater.

West Central Saskatchewan

The west central Saskatchewan area is roughly centered on the town of Kindersley, Saskatchewan. Currently, WestFire holds an average 92 percent working interest in 108,851 gross (100,004 net) undeveloped acres of land.

WestFire's exploration, development and production activities in the Plato and Dodsland areas of west central Saskatchewan are focused entirely on light oil in the Viking formation. In addition to its Crown land position, WestFire has entered into two lease option deals with a major North American resource company. These deals provide WestFire access to approximately 95 gross (95 net) sections of land in the Plato and Dodsland areas. During 2011, WestFire entered into a farmout deal with a private Canadian company on its Dodsland lease option acreage.

GLJ assigned 4,416 MBOE of proved reserves and 7,730 MBOE of proved plus probable reserves to the Viking core areas of west central Saskatchewan effective December 31, 2011. During 2011, the Dodsland/Plato area provided WestFire with average production of 485 BOE/d (including 664 Mcf/d gas) from 220 gross (209.7 net) wells. The majority of this production is from the Viking formation. The majority of WestFire's Viking production in west central Saskatchewan is operated by WestFire. The majority of WestFire's west central Saskatchewan production is transported by WestFire and is processed at its wholly-owned facilities.

During 2011, WestFire drilled 24 gross (16.5 net) Viking horizontal light oil wells at Plato and Dodsland.

Kaybob South, West Central Alberta

The Kaybob South Beaverhill Lake Unit No. 1 (“Unit”) is located approximately 10 kilometres southwest of the town of Fox Creek, Alberta. WestFire is operator of the Unit and holds a 90.7 percent working interest.

WestFire's development and production activities in the Unit are entirely directed toward liquids-rich natural gas in the Swan Hills member of the Beaverhill Lake Formation. WestFire’s interest in the Unit was obtained through the corporate acquisition of Orion Oil and Gas on June 30, 2011.

GLJ assigned 10,763 MBOE of proved reserves and 14,212 MBOE of proved plus probable reserves to the Unit effective December 31, 2011. During 2011, the Unit provided WestFire with average production of 1,398 BOE/d (including 4,341 Mcf/d gas) from 34 gross (30.1 net) wells. As at December 31, 2011, all of WestFire's production in the Unit is operated by WestFire. WestFire gathers its own production from the Unit and transports it to the SEMCams-operated KA Plant for processing.

Since acquiring its Unit working interest in 2011, WestFire has drilled two gross (1.8 net) Swan Hills liquids-rich natural gas wells.

Oil And Gas Wells

The following table sets forth the number and status of wells in which the Corporation had a working interest as at December 31, 2011.

	Oil Wells				Conventional Natural Gas Wells			
	Producing		Non-Producing		Producing		Non-Producing	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Alberta	495	462.3	47	40.1	153	125.4	76	51.5
Saskatchewan	264	237.9	33	25.0	24	18.2	17	14.1
British Columbia	0	0	0	0	0	0	1	0.3
Total	759	700.2	80	65.1	177	143.6	94	65.9

Properties With No Attributed Reserves

The following table sets out the Corporation's unproved properties as at December 31, 2011.

	Undeveloped Acres	
	Gross	**Net**
Alberta	150,562	110,148
British Columbia	3,300	1,031
Saskatchewan	109,331	141,584
Total	263,193	211,663

The Corporation expects that rights to explore develop and exploit 38,905 net acres of its undeveloped land holdings (valued at $4,324,318) will expire by December 31, 2012; a portion may be continued. WestFire plans to submit applications to continue selected portions of the above acreage, and may consider the possibility of drilling on selected portions of such expiring acreage.

Significant Factors or Uncertainties Relevant to Properties With No Attributed Reserves

See "Additional Information Relating to Reserves Data – Significant Factors or Uncertainties" above.

Forward Contracts

WestFire entered into contracts for management of commodity price risk. Commodity price risk is the risk that the fair value of future cash flows will fluctuate as a result of changes in commodity prices.

As of December 31, 2011, the Company had outstanding crude oil contracts as follows:

Type	Volume	Price per barrel or GJ (Cdn $)	Commencement date	Termination date
Swap (WTI)	350	$90.70	January 2012	March 2012
Costless Collar (WTI)	350	$80.00-$99.00	January 2012	March 2012
Swap (WTI)	750	$97.45	January 2012	June 2012
Costless Collar (WTI)	750	$90.00-$102.00	January 2012	June 2012
Costless Collar (WTI)	200	$95.00-$115.85	January 2012	December 2012
Swap (WTI)	200	$90.60	January 2012	December 2012
Swap (WTI)	350	$91.10	April 2012	June 2012
Costless Collar (WTI)	350	$80.00-$100.45	April 2012	June 2012
Swap (WTI) (1)	500	$105.10	April 2012	December 2012
Swap (WTI)	500	$91.25	July 2012	December 2012
Costless Collar (WTI)	500	$85.00-$95.05	July 2012	December 2012
Swap (WTI)	500	$92.75	July 2012	December 2012
Costless Collar (WTI)	100	$85.00-$97.90	July 2012	December 2012
Costless Collar (WTI)	400	$85.00-$99.15	July 2012	December 2012
Swap (WTI)	500	$91.25	July 2012	December 2012

Type	Volume	Price per barrel or GJ (Cdn $)	Commencement date	Termination date
Costless Collar (WTI)	500	$85.00-$95.05	July 2012	December 2012
Swap (WTI)	500	$92.75	July 2012	December 2012
Costless Collar (WTI)	100	$85.00-$97.90	July 2012	December 2012
Costless Collar (WTI)	400	$85.00-$99.15	July 2012	December 2012
Swap (WTI) (1)	500	$106.40	July 2012	December 2012
Swap (WTI) (1)	500	$105.10	January 2013	June 2013
Costless Collar (WTI)	400	$85.00-$109.05	January 2013	September 2013
Swap (WTI)	600	$97.05	January 2013	December 2013
Swap (WTI) (1)	1,600	$100.30	January 2013	December 2013

Note:

(1) Entered into subsequent to year end

Additional Information Concerning Abandonment and Reclamation Costs

The following sets forth certain information regarding WestFire's anticipated abandonment and reclamation costs for surface leases, wells, facilities and pipelines.

(a) WestFire has estimated the cost to perform well abandonment and reclamation by taking into account well depths, geographical location, existing well status, tangible assets and environmental factors. A well's abandonment is scheduled to occur after the Total Proved plus Probable production forecast deems the well no longer capable of production. Where possible, a well's abandonment is scheduled as part of a multi-well program to achieve an economy of scale.

(b) The total number of wells in which WestFire will incur this cost is 1,134 gross (997.6 net) wells.

(c) The expected cost to be incurred, net of salvage value is $31.4 million without discount and $15.8 million using a discount rate of 10%.

(d) Of the abandonment and reclamation costs disclosed in paragraph (c) above, $33.1 million undiscounted and $11.7 million discounted at 10% were deducted by GLJ as abandonment costs in the Total Proved plus Probable evaluation. The GLJ evaluation includes abandonments for wells WestFire has not drilled to date, does not include the abandonment of leases, facilities or pipelines and does not include the salvage or reclamation for existing wells, leases, facilities or pipelines.

(e) $4.4 million of the $31.4 million of undiscounted abandonment and reclamation costs disclosed in paragraph (c) above are expected to be paid in the next three financial years by WestFire.

Tax Horizon

Depending upon production, commodity prices and capital spending levels, WestFire does not currently anticipate paying current cash income taxes in the next two years.

Costs Incurred

The following table summarizes cash and non-cash capital expenditures (including corporate acquisitions and capitalized general and administrative expenses) incurred by WestFire with respect to the WestFire assets for the year ending December 31, 2011.

	Capital Expenditures ($000s)
Property acquisition costs	
Proved properties	385,336
Unproved properties	-
Development Costs	146,068
Exploration Costs	11,071
Total	542,475

Exploration and Development Activities

The following table sets forth the gross and net exploratory and development wells on the WestFire assets in which WestFire participated during the year ending December 31, 2011.

	Development Wells		**Exploration Wells**		**Total Wells**	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
Light and Medium Oil	97	85.5	-	-	97	85.5
Heavy Oil	16	16.0	-	-	16	16.0
Natural Gas	2	1.8	-	-	2	1.8
Standing	-	-	-	-	-	-
Exploratory Strat Tests	-	-	16	16.0	16	16.0
Total	115	103.3	16	16.0	131	119.3

Production Estimates

The following table sets out the gross volume of production estimated for the year ending December 31, 2012 in the estimates of WestFire's future net revenue from gross proved producing, total proved and proved plus probable reserves as estimated in the GLJ Report. Two properties, Kaybob South and Redwater, contribute over 20% of the Company's total production.

	Entity	Light and Medium Oil	Heavy Oil	Conventional Natural Gas	Natural Gas Liquids	Oil Equivalent
		(Bbls/d)	(Bbls/d)	(Mcf/d)	(Bbls/d)	(Bbls/d)
PROVED PRODUCING						
	Kaybob South	-	-	7,558	951	2,210
	Redwater	1,266	-	736	6	1,395
	Other Properties	1,725	409	8,765	65	3,660
TOTAL: PROVED PRODUCING		2,992	409	17,059	1,022	7,266
TOTAL PROVED						
	Kaybob South	-	-	7,630	960	2,232
	Redwater	2,216	-	1,069	7	2,401
	Other Properties	2,496	462	9,179	69	4,557
TOTAL: TOTAL PROVED		4,712	462	17,878	1,036	9,190
PROVED PLUS PROBABLE						
	Kaybob South	-	-	7,713	970	2,256
	Redwater	2,378	-	1,128	7	2,573
	Other Properties	2,904	492	9,624	73	5,073
TOTAL: PROVED PLUS PROBABLE		5,282	492	18,465	1,051	9,902

Production History

The following table discloses, on a quarterly basis for the last four completed quarters, certain information in respect of production, product prices received, royalties paid, production costs and resulting netback for the WestFire assets.

	Quarter Ended			
	2011			
	December 31	September 30	June 30	March 31
Average Daily Production [(1)]				
Gas (Mcf/d)	16,376	17,766	6,392	6,580
Crude Oil and NGL's (Bbls/d)	5,872	5,499	2,243	1,676
Combined (Boe/d)	8,601	8,460	3,308	2,773
Average Prices Received [(2)]				
Gas ($/Mcf)	3.36	4.19	4.70	4.72
Crude Oil and NGL's ($/Bbl)	87.14	84.18	89.04	72.09
Combined ($/Boe)	74.13	67.05	72.70	55.03
Royalties Paid				
Gas ($/Mcf)	(0.26)	0.44	(0.15)	0.28
Crude Oil and NGL's ($/Bbl)	11.71	14.29	8.17	8.11
Combined ($/Boe)	7.49	10.21	5.24	5.57
Production Costs [(3)]				
Gas ($/Mcf)	0.58	0.54	1.54	1.79
Crude Oil and NGL's ($/Bbl)	25.35	27.61	18.42	24.52
Combined ($/Boe)	16.83	16.57	13.89	17.42
Netback Received [(4)]				
Gas ($/Mcf)	0.43	0.44	3.45	2.80
Crude Oil and NGL's ($/Bbl)	62.31	56.27	63.67	40.66
Combined ($/Boe)	43.63	38.71	50.27	31.73

Notes:

(1) Before deduction of royalties.
(2) After deduction of transportation costs.
(3) Operating expenses are composed of direct costs incurred to operate both oil and gas wells. A number of assumptions have been made in allocating these costs between oil, natural gas and natural gas liquids production. Operating recoveries associated with operated properties were excluded from operating costs and accounted for as a reduction to general and administrative costs.

(4) Netbacks are calculated by subtracting royalties, operating costs and losses/gains on commodity and foreign exchange contracts from revenues.

The following table sets forth the average daily production volumes for the year ended December 31, 2011 for each of the important fields comprising the WestFire assets.

Area	**Conventional Natural Gas (Mcf/d)**	**Crude Oil and NGL's (Bbls/d)**	**Boe (Boe/d)**
Redwater/Provost, Alberta	1,632	2,143	2,415
Kaybob/Bigstone, Alberta	5,093	679	1,527
West central Saskatchewan	664	374	485
Lloydminster, Alberta	196	497	529
Alberta gas	3,897	117	765
Other Properties	346	29	88
Total	11,822	3,839	5,809

WestFire's production for the year ended December 31, 2011 with respect to the properties comprising the WestFire assets was 33.9% natural gas and 66.1% crude oil and NGL's.

For the year ended December 31, 2011, 13.6% of the gross revenue with respect to the properties comprising the WestFire assets was derived from natural gas production and 86.4% of the gross revenue was derived from crude oil and NGL's.

WestFire currently plans to market 100% of its natural gas, crude oil and NGL's to a third party based on daily indexed prices.

DIVIDENDS

WestFire has not declared any cash dividends or distributions on the outstanding Common Shares. The Board of Directors of WestFire will determine the actual timing, payment and amount of dividends, if any, that may be paid by WestFire from time to time based upon, among other things, the cash flow, results of operations and financial conditions of WestFire, the needs for funds to finance ongoing operations and other business considerations as the board of directors of WestFire considers relevant. Payment of dividends may be subject to the consent of the Corporation's lenders from time to time.

DESCRIPTION OF CAPITAL STRUCTURE

General Description of Capital Structure

The Corporation is authorized to issue an unlimited number of Common Shares, an unlimited number of non-voting common shares ("**Non-Voting Shares**") and an unlimited number of non-voting convertible shares (the "**Non-Voting Convertible Shares**"). The following is a description of the rights, privileges, restrictions and conditions attaching to the share capital of the Corporation.

Common Shares

The holders of Common Shares are entitled to one vote for each Common Share held on all matters to be voted on by such holders and are entitled to receive *pro rata*, such dividends as may be declared by the board of directors of the Corporation out of funds legally available therefore and to receive pro rata, the remaining property of the Corporation on dissolution.

Non-Voting Shares

The holders of Non-Voting Shares are entitled to receive notice and attend shareholder meetings but shall not, except as required by law, be entitled to vote on any matter and are entitled to receive *pro rata*, such dividends as may be declared by the board of directors of the Corporation, out of funds legally available therefore and to receive *pro rata*, the remaining property of the Corporation on dissolution.

Non-Voting Convertible Shares

The holders of Non-Voting Convertible Shares are entitled to receive notice of and to attend at any meeting of the shareholders of the Corporation but are not entitled to vote at any such meeting, except with respect to such matters and in the manner as to which voting rights are accorded to the holders of specified classes of shares pursuant to the provisions of the ABCA.

The holders of the Non-Voting Convertible Shares are entitled to receive dividends if, as and when declared by the Board of Directors equally, on a share-for-share basis, with the holders of Common Shares

In the event of liquidation, dissolution or winding-up of the affairs of the Corporation, whether voluntary or involuntary, or in the event of any other distribution of assets of the Corporation among its shareholders for the purpose of winding up its affairs, or in the event of a reduction or redemption of the capital stock of the Corporation, the holders of the Non-Voting Convertible Shares are entitled to receive an amount per share equal to that amount that is the fair market value of any property received by the Corporation as consideration for the issuance of such Non-Voting Convertible Shares divided by the number of Non-Voting Convertible Shares issued, in lawful money of Canada, the whole before any amount will be paid by the Corporation or any assets of the Corporation will be distributed to holders of Common Shares. After payment to the holders of the Non-Voting Convertible Shares of the amount so payable to them in accordance with the foregoing, they will not be entitled to share in any further distribution of property or assets of the Corporation.

Each holder of Non-Voting Convertible Shares has the right to transfer to any Person all or any of the holder's Non-Voting Convertible Shares, provided (i) the transferee would not be a Control Person (as defined below) of the Corporation after giving effect to the transfer and (ii) such transfer was made in compliance with all applicable securities laws.

Each holder of Non-Voting Convertible Shares has the right to convert all or any of the holder's Non-Voting Convertible Shares into Common Shares at the Conversion Ratio in the following circumstances:

(i) at any time, provided that the holder would not be a Control Person of the Corporation after giving effect to the conversion; or

(ii) upon a Change of Control Transaction, regardless of whether or not such Change of Control Transaction has been approved by the board of directors of the Corporation.

Each Non-Voting Convertible Share will be deemed to convert into Common Shares at the Conversion Ratio immediately upon the sale, transfer, conveyance or other disposition of such Non-Voting Convertible Share, whether by way of a sale, transfer, conveyance or other disposition that is exempt from the prospectus requirements under applicable securities laws, or a distribution to the public or a secondary offering completed by way of prospectus, provided that the transferee would not be a Control Person of the Corporation after giving effect to the sale, transfer, conveyance or other disposition and the conversion of such Non-Voting Convertible Shares.

The Corporation has the right, following the date that is three years after the issuance date of the Non-Voting Convertible Shares, at its sole option to require that holders of Non-Voting Convertible Shares convert all issued and outstanding Non-Voting Convertible Shares held by them into Common Shares.

For the purposes of the foregoing:

"**CDS**" means the CDS Clearing and Depository Services Inc. and its successors;

"**CDS Participant**" means a broker, dealer, bank, other financial institution or other person who, directly or indirectly, from time to time, effects book-based transfers with CDS and pledges of securities deposited with CDS;

"**Change of Control Transaction**" means any of the following:

(iii) an amalgamation, merger, business combination, consolidation, recapitalization, reorganization, liquidation, dissolution or winding-up in respect of the Corporation or any other transaction of the Corporation with another Corporation or entity, other than a wholly-owned subsidiary, or an arrangement pursuant to the *Business Corporations Act* (Alberta) involving the Corporation or another transaction pursuant to which a Person, or group of Persons acting jointly or in concert, acquires all of the issued and outstanding Common Shares;

(iv) the direct or indirect sale, lease or other disposition (or any long-term supply arrangement, licence or other arrangement having the same economic effect as a sale) of all or substantially all of the consolidated assets, revenues or earnings, as applicable, or undertaking of the Corporation;

(v) the direct or indirect acquisition by any Person, or group of Persons acting jointly or in concert, of voting control or direction over an aggregate of 50% or more of the outstanding Common Shares, by take-over bid, issuance of Common Shares or otherwise; or

(vi) any similar transaction or series of transactions involving the Corporation or any of its subsidiaries, directly or indirectly.

"**Control Person**" means (a) a person or company who holds more than 20 per cent of the voting rights attached to all outstanding voting securities of the Corporation, or (b) each person or company in a combination of persons or companies, acting in concert by virtue of an agreement, arrangement, commitment or understanding, which holds more than 20 per cent of the voting rights attached to all outstanding voting securities of the Corporation;

"**Conversion Ratio**" means the number of Common Shares issuable upon conversion of each Non-Voting Convertible Share, which shall initially be one Common Share, subject to adjustment in accordance with the terms or the Non-Voting Convertible Shares;

"**Exchange**" means the Toronto Stock Exchange or, if applicable, such other stock exchange on which the Common Shares are principally traded; and

"**Person**" means an individual, partnership, corporation, trust, unincorporated association, joint venture or other entity and includes a group of Persons acting jointly or in concert.

Constraints

There are currently no constraints imposed on the ownership of securities of the Corporation to ensure that WestFire has a required level of Canadian ownership.

Ratings

WestFire has not asked for and received a stability rating, or to the knowledge of WestFire, has received any other kind of rating, including, a provisional rating, from one or more approved rating organizations for securities of WestFire that are outstanding and which continue in effect.

MARKET FOR SECURITIES

Trading Price and Volume

The Common Shares trade on the Toronto Stock Exchange (the "**TSX**") under the symbol WFE. The following is the price ranges and volume traded or quoted on the TSX on a monthly basis for each month of the most recently completed financial year.

	Common Shares		
	Price Range		
	High ($/share)	Low ($/share)	Trading Volume
2011			
January	8.04	6.81	3,505,231
February	9.99	8.02	6,350,249
March	9.27	7.46	2,635,076
April	8.81	7.66	3,851,082
May	8.57	6.93	3,487,399
June	7.71	6.36	2,624,030
July	8.15	6.96	2,506,302
August	7.26	5.33	3,596,759
September	6.46	4.21	2,275,313
October	5.35	3.51	3,216,796
November	5.36	4.22	2,392,737
December	5.85	4.61	4,683,500

Prior Sales

Other than options to acquire Common Shares, there is no class of securities of WestFire that is outstanding and not listed or quoted on a marketplace.

ESCROWED SECURITIES AND SECURITIES SUBJECT TO CONTRACTUAL RESTRICTION ON TRANSFER

To the Company's knowledge, as of December 31, 2011, there were no securities of any class of WestFire held in escrow or that are subject to a contractual restriction on transfer other than as set forth under the heading "Material Contracts".

DIRECTORS AND OFFICERS

Name, Occupation and Security Holding

The names, province or state, and country of residence, positions and offices held with the Corporation, and principal occupation of the directors and executive officers of the Corporation are set out below and, in the case of directors, the period each has served as a director of the Corporation.

Name, Province or State and Country of Residence	Position and Office Held	Principal Occupation During the Five Preceding Years	Director Since
Ed Chwyl[(2)(3)] British Columbia, Canada	Director and Executive Chairman	Lead Independent Director of Baytex Energy Corp. (previously Baytex Energy Ltd.) (Baytex Energy Trust) since February 17, 2009. Prior thereto, Chairman of the Board of Directors of Baytex Energy Ltd. (Baytex Energy Trust) since 2003.	December 13, 2007
Lowell E. Jackson Alberta, Canada	President, Chief Executive Officer and Director	President and Chief Executive Officer of WestFire since December 2007. Prior thereto, President and Chief Executive Officer of Real Resources Inc. from 1997 to 2007.	December 13, 2007
John A. Brussa[(2)] Alberta, Canada	Director	Partner, Burnet, Duckworth & Palmer LLP (law firm).	December 13, 2007
Raymond T. Chan[(1)] Alberta, Canada	Director	Executive Chairman of Baytex Energy Corp. (previously Baytex Energy Ltd.) (Baytex Energy	December 13, 2007

Name, Province or State and Country of Residence	Position and Office Held	Principal Occupation During the Five Preceding Years	Director Since
		Trust) since January 1, 2009. Prior thereto, President of Baytex Energy Ltd. (Baytex Energy Trust) from September 2003 to November 2007 and Chief Executive Officer of Baytex Energy Ltd. (Baytex Energy Trust) from September 2003 to December 2008.	
Michael McGovern[(1)(2)(3)] Texas, U.S.A.	Director	Executive Advisor to Cadent Energy Partners LLC since January 2008. Prior thereto, President and Chief Executive Officer of Pioneer Companies Inc. from 2002 to 2007.	July 4, 2008
Christopher L. Fong[(1)(3)] Alberta, Canada	Director	Independent businessman since May 2009. Prior thereto Global Head Corporate Banking, Energy with RBC Capital Markets.	March 29, 2010
Roger Thomas[((2)(3)] Alberta, Canada	Director	Independent businessman since June 2009. Prior thereto Executive Vice President, North America of Nexen Inc.	June 30, 2011
Frank P. Muller Alberta, Canada	Senior Vice President, Exploration	Senior Vice President of WestFire since December 2007. Prior thereto, Senior Vice President, Exploration of Real Resources Inc. from 2001 to 2007.	N/A
Darrin R. Drall Alberta, Canada	Vice President, Engineering	Vice President, Engineering of WestFire since January 2008. Prior thereto, Vice President, Engineering and Operations of Burmis Energy Inc. from July 2006 to January 2008. Prior thereto, Vice President, Corporate Development of Burmis Energy Inc. from January 2003 to July 2006.	N/A
Christopher J. Bennett Alberta, Canada	Vice President, Land	Vice President, Land since October 2010. Prior thereto Vice President Land and Contracts of West Energy Ltd. from December 2005 to May 2010; prior thereto Manager, Land and Contracts of West Energy Ltd. from September 2005 to November 2005; prior thereto Partner of Thackray Burgess (a law firm) from June 1997 to August 2005.	N/A
Jeff Holmgren Alberta, Canada	Vice President, Finance and Chief Financial Officer	Vice President, Finance and Chief Financial Officer since November 2011. Prior thereto auditor at Ernst & Young LLP from 2010 to 2011; prior thereto Vice President Finance and Chief Financial Officer of Rodinia Oil Corp. from 2008 to 2010 while concurrently Vice President Finance and Chief Financial Officer of Petro Frontier Corp. from 2009 to 2010; prior thereto Senior Financial Analyst at Progress Energy Trust from 2004-2008.	N/A
Cameron King Alberta, Canada	Vice President, Operations	Vice President, Operations since November 2011. Prior thereto Senior Advisor, Business	N/A

Name, Province or State and Country of Residence	Position and Office Held	Principal Occupation During the Five Preceding Years	Director Since
		Development for PennWest Exploration from June 2011 to November 2011, prior thereto Senior Operations Manager for PennWest Exploration from November 2008 to June 2011.	
Alan T. Pettie Alberta, Canada	Secretary	Partner, Burnet, Duckworth & Palmer LLP (law firm).	N/A

Notes:

(1) Member of the Audit Committee.
(2) Member of the Corporate Governance and Compensation Committee
(3) Member of the Reserves, Safety and Environmental Committee.
(4) WestFire does not have an executive committee of its board of directors.

The term of office of each director expires at the next annual meeting of the shareholders of the Corporation.

As of the date of this Annual Information Form, the directors and executive officers of WestFire, as a group, beneficially owned, or controlled or directed, directly or indirectly, 1,920,536 Common Shares or approximately 2.3% of the issued and outstanding Common Shares.

Cease Trade Orders, Bankruptcies, Penalties or Sanctions

Cease Trade Orders

To WestFire's knowledge, other than as disclosed herein, no director or executive officer of the Corporation is, as at the date hereof, or was within 10 years before the date hereof, a director, chief executive officer or chief financial officer of any issuer (including the Corporation) that: (a) was subject to an order that was issued while the director or executive officer was acting in the capacity as director, chief executive office or chief financial officer; or (b) was subject to an order that was issued after the director or executive officer ceased to be a director, chief executive officer or chief financial officer and which resulted from an event that occurred while that person was acting in the capacity as director, chief executive officer or chief financial officer. For the purposes of the above, "order" means a cease trade order, an order similar to a cease trade order or an order that denied the relevant company access to any exemption under securities legislation that was in effect for a period of more than 30 consecutive days.

Bankruptcies

To WestFire's knowledge, other than as disclosed herein, no director or executive officer of the Corporation, or a shareholder holding a sufficient number of securities of the Corporation to affect materially the control of the Corporation (a) is, as at the date hereof, or has been, within the 10 years before the date hereof, a director or executive officer of any issuer (including the Corporation) that, while that person was acting in that capacity, or within a year of that person ceasing to act in that capacity, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets or (b) has, within the 10 years before the date hereof, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or become subject to or instituted any proceedings, arrangement or compromise with creditors, or had a receiver, receiver manager or trustee appointed to hold the assets of the director, executive officer or shareholder.

Michael McGovern was the Chief Executive Officer and a director of Coho Energy, Inc. ("**Coho**"), a corporation engaged in oil and gas exploitation, exploration and development, from April 2000 to December 2002. Coho filed for bankruptcy on February 6, 2002 and its assets were sold and the proceeds were distributed to Coho's secured creditors. Michael McGovern was also a director of Tronox, Inc. ("**Tronox**"). Tronox has filed for bankruptcy and is currently considering a sale and re-organization.

Penalties or Sanctions

To WestFire's knowledge, other than as disclosed herein**,** no director or executive officer of the Corporation, or a shareholder holding a sufficient number of securities of the Corporation to affect materially the control of the Corporation, has been subject to (a) any penalties or sanctions imposed by a court relating to securities legislation or by a securities regulatory authority or has entered into a settlement agreement with a securities regulatory authority or (b) any other penalties or sanctions imposed by a court or regulatory body that would likely be considered important to a reasonable investor in making an investment decision.

Conflicts of Interest

The directors or officers of the Corporation may also be directors or officers of other oil and gas companies or otherwise involved in natural resource exploration and development and situations may arise where they are in a conflict of interest with the Corporation. Conflicts of interest, if any, which arise will be subject to and governed by procedures prescribed by the ABCA which require a director or officer of a corporation who is a party to, or is a director or an officer of, or has a material interest in any person who is a party to, a material contract or proposed material contract with the Corporation disclose his or her interest and, in the case of directors, to refrain from voting on any matter in respect of such contract unless otherwise permitted under the ABCA.

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

Legal Proceedings

There are no legal proceedings WestFire is or was a party to, or that any of its property is or was the subject of, during WestFire's financial year, nor are any such legal proceedings known to WestFire to be contemplated, that involves a claim for damages, exclusive of interest and costs, exceeding 10% of the current assets of WestFire.

Regulatory Actions

There are no:

(a) penalties or sanctions imposed against WestFire by a court relating to securities legislation or by a securities regulatory authority during WestFire's financial year;

(b) other penalties or sanctions imposed by a court or regulatory body against WestFire that would likely be considered important to a reasonable investor in making an investment decision; and

(c) settlement agreements WestFire entered into before a court relating to securities legislation or with a securities regulatory authority during WestFire's financial year.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

There is no material interest, direct or indirect, of any (a) director or executive officer of WestFire; (b) person or company that beneficially owns, or controls or directs, directly or indirectly, more than 10% of any class or series of WestFire's voting securities; and (c) associate or affiliate of any of the persons or companies referred to in (a) or (b) in any transaction within the three most recently completed financial years or during the current financial year that has materially affected or is reasonably expected to materially affect WestFire.

TRANSFER AGENTS AND REGISTRARS

Valiant Trust Company of Canada, at its principal offices in Calgary, Alberta and Toronto, Ontario, is the transfer agent and registrar of the Common Shares.

WestFire acts as the transfer agent and registrar of the Non-Voting Shares.

MATERIAL CONTRACTS

Except for contracts entered into in the ordinary course of business, the Corporation has not entered into any material contracts within the most recently completed financial year or before WestFire's most recently completed financial year which are still in effect other than the Investor Agreement (as defined below).

In connection with WestFire's acquisition of Orion, WestFire and Sprott Resource Corp. ("**SRC**") entered into an investor agreement (the "**Investor Agreement**"). Pursuant to the Investor Agreement, SRC has agreed that, without the prior written consent of WestFire:

(i) it will not sell its Common Shares acquired by it pursuant to the Arrangement or its Common Shares acquired upon the conversion of Non-Voting Convertible Shares for a period beginning on the effective date of the Arrangement (the "**Effective Date**") and ending on the earlier of (i) the date that is 18 months following the Effective Date, and (ii) the date of the completion of a "Change of Control Transaction" (as defined in the Investor Agreement); and

(ii) it will not sell its Non-Voting Convertible Shares, in a single transaction or series of related transactions, to one or more purchasers, unless the aggregate gross proceeds due to SRC as a result of such transaction(s) exceed CDN$10,000,000.

The Investor Agreement also provides for certain "drag-along" rights in the event of a change of control of WestFire for the benefit of WestFire and certain "demand registration" rights for the benefit of SRC. The Non-Voting Convertible Shares are substantially similar to the Common Shares except that they:

(i) carry no voting rights;

(ii) are transferable to any Person and convertible (in whole or in part) into Common Shares on a one-for-one basis provided the transfer or conversion, as the case may be, would not result in the transferee or holder, respectively, holding 20% or more of the voting rights attached to all voting securities of WestFire; and

(iii) in the event of a liquidation of WestFire, the holders of Non-Voting Convertible Shares will be entitled only to an amount that is equal to the fair market value of any property received by WestFire as consideration for the issuance of such shares before any assets shall be distributed to holders of Common Shares.

See "Description of Capital Structure – Non-Voting Convertible Shares".

INTERESTS OF EXPERTS

Names of Experts

The only persons or companies who are named as having prepared or certified a report, valuation, statement or opinion described or included in a filing, or referred to in a filing, made under National Instrument 51-102 by the Corporation during, or relating to, the Corporation's most recently completed financial year, and whose profession or business gives authority to the report, valuation, statement or opinion made by the person or company, are PricewaterhouseCoopers LLP, the Corporation's independent auditors, and GLJ, the Corporation's independent engineering evaluators.

Interests of Experts

To the Corporation's knowledge, no registered or beneficial interests, direct or indirect, in any securities or other property of the Corporation or of one of the Corporation's associates or affiliates (i) were held by GLJ, when GLJ prepared the report, valuation, statement or opinion in question, (ii) were received by GLJ after GLJ prepared the report, valuation, statement or opinion in question, or (iii) is to be received by GLJ.

Neither GLJ nor any director, officer or employee of GLJ is or is expected to be elected, appointed or employed as a director, officer or employee of the Corporation or of any associate or affiliate of the Corporation.

WestFire's auditors are PricewaterhouseCoopers LLP, Chartered Accountants, who have prepared an independent auditors' report dated March 26, 2012 in respect of WestFire's financial statements as at December 31, 2011 and December 31, 2010 and for each of the years in the two year period ended December 31, 2011. PricewaterhouseCoopers LLP has advised that they are independent with respect to WestFire within the meaning of the Rules of Professional Conduct of the Institute of Chartered Accountants of Alberta.

INDUSTRY CONDITIONS

Companies operating in the oil and natural gas industry are subject to extensive regulation and control of operations (including land tenure, exploration, development, production, refining and upgrading, transportation, and marketing) as a result of legislation enacted by various levels of government and with respect to the pricing and taxation of oil and natural gas through agreements among the governments of Canada, Alberta, British Columbia and Saskatchewan, all of which should be carefully considered by investors in the oil and gas industry. It is not expected that any of these regulations or controls will affect the Corporation's operations in a manner materially different than they will affect other oil and natural gas companies of similar size. All current legislation is a matter of public record and the Corporation is unable to predict what additional legislation or amendments may be enacted. Outlined below are some of the principal aspects of legislation, regulations and agreements governing the oil and gas industry in western Canada.

Pricing and Marketing

Oil

The producers of oil are entitled to negotiate sales contracts directly with oil purchasers, with the result that the market determines the price of oil. Oil prices are primarily based on worldwide supply and demand. The specific price depends in part on oil quality, prices of competing fuels, distance to market, value of refined products, the supply/demand balance and contractual terms of sale. Oil exporters are also entitled to enter into export contracts with terms not exceeding one year in the case of light crude oil and two years in the case of heavy crude oil, provided that an order approving such export has been obtained from the National Energy Board of Canada (the "**NEB**"). Any oil export to be made pursuant to a contract of longer duration (to a maximum of 25 years) requires an exporter to obtain an export licence from the NEB.

Natural Gas

The price of the vast majority of natural gas produced in western Canada is now determined through highly liquid market hubs such as the Alberta "NIT" (Nova Inventory Transfer) hub rather than through direct negotiation between buyers and sellers. Natural gas exported from Canada is subject to regulation by the NEB and the Government of Canada. Exporters are free to negotiate prices and other terms with purchasers, provided that the export contracts must continue to meet certain other criteria prescribed by the NEB and the Government of Canada. Natural gas (other than propane, butane and ethane) exports for a term of less than two years or for a term of two to 20 years (in quantities of not more than 30,000 m^3/day) must be made pursuant to an NEB order. Any natural gas export to be made pursuant to a contract of longer duration (to a maximum of 25 years) or for a larger quantity requires an exporter to obtain an export licence from the NEB.

The governments of Alberta, British Columbia and Saskatchewan also regulate the volume of natural gas that may be removed from those provinces for consumption elsewhere based on such factors as reserve availability, transportation arrangements and market considerations.

The North American Free Trade Agreement

The North American Free Trade Agreement ("**NAFTA**") among the governments of Canada, the United States and Mexico became effective on January 1, 1994. In the context of energy resources, Canada continues to remain free to determine whether exports of energy resources to the United States or Mexico will be allowed, provided that any export restrictions do not: (i) reduce the proportion of energy resources exported relative to the total supply of goods of the party maintaining the restriction as compared to the proportion prevailing in the most recent 36 month period; (ii) impose an export price higher than the domestic price (subject to an exception with respect to certain measures which only restrict the volume of exports); and (iii) disrupt normal channels of supply. All three signatory countries are prohibited from imposing a minimum or maximum export price requirement in any circumstance where any other form of quantitative restriction is prohibited. The signatory countries are also prohibited from imposing a minimum or maximum import price requirement except as permitted in enforcement of countervailing and anti-dumping orders and undertakings. NAFTA requires energy regulators to ensure the orderly and equitable implementation of any regulatory changes and to ensure that the application of those changes will cause minimal disruption to contractual arrangements and avoid undue interference with pricing, marketing and distribution arrangements, all of which are important for Canadian oil and natural gas exports.

Royalties and Incentives

General

In addition to federal regulation, each province has legislation and regulations which govern royalties, production rates and other matters. The royalty regime in a given province is a significant factor in the profitability of oil sands projects, crude oil, natural gas liquids, sulphur and natural gas production. Royalties payable on production from lands other than Crown lands are determined by negotiation between the mineral freehold owner and the lessee, although production from such lands is subject to certain provincial taxes and royalties. Royalties from production on Crown lands are determined by governmental regulation and are generally calculated as a percentage of the value of gross production. The rate of royalties payable generally depends in part on prescribed reference prices, well productivity, geographical location, field discovery date, method of recovery and the type or quality of the petroleum product produced. Other royalties and royalty-like interests are, from time to time, carved out of the working interest owner's interest through non-public transactions. These are often referred to as overriding royalties, gross overriding royalties, net profits interests, or net carried interests.

Occasionally the governments of the western Canadian provinces create incentive programs for exploration and development. Such programs often provide for royalty rate reductions, royalty holidays or royalty tax credits and are generally introduced when commodity prices are low to encourage exploration and development activity by improving earnings and cash flow within the industry.

Alberta

Producers of oil and natural gas from Crown lands in Alberta are required to pay annual rental payments, currently at a rate of $3.50 per hectare, and make monthly royalty payments in respect of oil and natural gas produced.

Royalties are currently paid pursuant to "The New Royalty Framework" (implemented by the *Mines and Minerals (New Royalty Framework) Amendment Act, 2008*) and the "Alberta Royalty Framework", which was implemented in 2010.

Royalty rates for conventional oil are set by a single sliding rate formula which is applied monthly and incorporates separate variables to account for production rates and market prices. Effective January 1, 2011, the maximum royalty payable under the royalty regime was set at 40%. The royalty curve for conventional oil announced on May 27, 2010 amends the price component of the conventional oil royalty formula to moderate the increase in the royalty rate at prices higher than $\$535/m^3$ compared to the previous royalty curve.

Royalty rates for natural gas under the royalty regime are similarly determined using a single sliding rate formula incorporating separate variables to account for production rates and market prices. Effective January 1, 2011, the maximum royalty payable under the royalty regime was set at 36%. The royalty curve for natural gas announced on May 27, 2010 amends the price component of the natural gas royalty formula to moderate the increase in the royalty rate at prices higher than $5.25/GJ compared to the previous royalty curve.

Oil sands projects are also subject to the Alberta's royalty regime. Prior to payout of an oil sands project, the royalty is payable on gross revenues of an oil sands project. Gross revenue royalty rates range between 1-9% depending on the market price of oil, determined using the average monthly price, expressed in Canadian dollars, for WTI crude oil and Cushing, Oklahoma: rates are 1% when the market price of oil is less than or equal to $55 per barrel and increase for every dollar of market price of oil increase to a maximum of 9% when oil is priced at $120 or higher. After payout, the royalty payable is the greater of the gross revenue royalty based on the gross revenue royalty rate of 1-9% and the net revenue royalty based on the net revenue royalty rate. Net revenue royalty rates start at 25% and increase for every dollar of market price of oil increase above $55 up to 40% when oil is priced at $120 or higher. In addition, concurrently with the implementation of the New Royalty Framework, the Government of Alberta renegotiated existing contracts with certain oil sands producers that were not compatible with the current royalty regime.

Producers of oil and natural gas from freehold lands in Alberta are required to pay annual freehold production taxes. The level of the freehold production tax is based on the volume of monthly production and a specified rate of tax for both oil and gas.

The Innovative Energy Technologies Program (the "**IETP**"), which is currently in place, has the stated objectives of increasing recovery from oil and gas deposits, finding technical solutions to the gas over bitumen issue, improving the recovery of bitumen by in-situ and mining techniques and improving the recovery of natural gas from coal seams. The IETP provides royalty adjustments to specific pilot and demonstration projects that utilize new or innovative technologies to increase recovery from existing reserves.

The Government of Alberta currently has in place two royalty programs, both of which commenced in 2008 and are intended to encourage the development of deeper, higher cost oil and gas reserves. A five-year program for conventional oil exploration wells over 2,000 metres provides qualifying wells with up to a $1 million or 12 months of royalty relief, whichever comes first, and a five-year program for natural gas wells deeper than 2,500 metres provides a sliding scale royalty credit based on depth of up to $3,750 per metre. On May 27, 2010, the natural gas deep drilling program was amended, retroactive to May 1, 2010, by reducing the minimum qualifying depth to 2,000 metres, removing a supplemental benefit of $875,000 for wells exceeding 4,000 metres that are spudded subsequent to that date, and including wells drilled into pools drilled prior to 1985, among other changes.

On November 19, 2008, the Government of Alberta announced the introduction of a five-year program of transitional royalty rates with the intent of promoting new drilling. The five-year transition option is designed to provide lower royalties at certain price levels in the initial years of a well's life when production rates are expected to be the highest. Under this program, companies drilling new natural gas or conventional deep oil wells (between 1,000 and 3,500 m) are given a one-time option, on a well-by-well basis, to adopt either the new transitional royalty rates or those outlined in the royalty regime. These options expired on February 15, 2011 and on January 1, 2014, all producers operating under the transitional royalty rates will automatically become subject to the royalty regime. The revised royalty curves for conventional oil and natural gas will not be applied to production from wells operating under the transitional royalty rates.

On March 3, 2009, the Government of Alberta announced a three-point incentive program in order to stimulate new and continued economic activity in Alberta. One aspect of the program was a drilling royalty credit program which provided up to a $200 per metre royalty credit for new wells. The drilling credit program applied to wells that were drilled between April 1, 2009 and March 31, 2010 and has not been extended for wells drilled after March 31, 2010. Another aspect of the program was a new well royalty program which provided for a maximum 5% royalty rate for eligible new wells for the first twelve (12) productive months or until the regulated "volume cap" was reached. The *New Well Royalty Regulation*, providing for the permanent implementation of this incentive program, was approved by an Order-in-Council on March 17, 2011.

In addition to the foregoing, the Government of Alberta has implemented certain initiatives intended to accelerate technological development and facilitate the development of unconventional resources (the "**Emerging Resource and Technologies Initiative**"). Specifically:

Coalbed methane wells will receive a maximum royalty rate of 5% for 36 producing months on up to 750 MMcf of production, retroactive to wells that began producing on or after May 1, 2010;

Shale gas wells will receive a maximum royalty rate of 5% for 36 producing months with no limitation on production volume, retroactive to wells that began producing on or after May 1, 2010;

Horizontal gas wells will receive a maximum royalty rate of 5% for 18 producing months on up to 500 MMcf of production, retroactive to wells that commenced drilling on or after May 1, 2010; and

Horizontal oil wells and horizontal non-project oil sands wells will receive a maximum royalty rate of 5% with volume and production month limits set according to the depth of the well (including the horizontal distance), retroactive to wells that commenced drilling on or after May 1, 2010.

The Emerging Resource and Technologies Initiative will be reviewed in 2014, and the Government of Alberta has committed to providing industry with three years notice at that time if it decides to discontinue the program.

British Columbia

Producers of oil and natural gas from Crown lands in British Columbia are required to pay annual rental payments, currently at a rate of $3.50 per hectare, and make monthly royalty payments in respect of oil and natural gas produced. The amount payable as a royalty in respect of oil depends on the type and vintage of the oil, the quantity of oil produced in a month and the value of that oil. Generally, oil is classified as either light or heavy and the vintage of oil is based on the determination of whether the oil is produced from a pool discovered before October 31, 1975 ("old oil"), between October 31, 1975 and June 1, 1998 ("new oil"), or after June 1, 1998 ("third-tier oil"). The royalty calculation takes into account the production of oil on a well-by-well basis, the specified royalty rate for a given vintage of oil, the average unit selling price of the oil and any applicable royalty exemptions. Royalty rates are reduced on low productivity wells, reflecting the higher unit costs of extraction, and are the lowest for third-tier oil, reflecting the higher unit costs of both exploration and extraction.

The royalty payable in respect of natural gas produced on Crown lands is determined by a sliding scale formula based on a reference price, which is the greater of the average net price obtained by the producer and a prescribed minimum price. For non-conservation gas (not produced in association with oil), the royalty rate depends on the date of acquisition of the oil and natural gas tenure rights and the spud date of the well and may also be impacted by the select price, a parameter used in the royalty rate formula to account for inflation. Royalty rates are fixed for certain classes of non-conservation gas when the reference price is below the select price. Conservation gas is subject to a lower royalty rate than non-conservation gas as an incentive for the production and marketing of natural gas which might otherwise have been flared.

Producers of oil and natural gas from freehold lands in British Columbia are required to pay monthly freehold production taxes. For oil, the level of the freehold production tax is based on the volume of monthly production. For natural gas, the freehold production tax is determined using a sliding scale formula based on the reference price similar to that applied to natural gas production on Crown land, and depends on whether the natural gas is conservation gas or non-conservation gas.

British Columbia maintains a number of targeted royalty programs for key resource areas intended to increase the competitiveness of British Columbia's low productivity wells. These include both royalty credit and royalty reduction programs, including the following:

Summer Royalty Credit Program providing a royalty credit of 10% of drilling and completion costs up to $100,000 for wells drilled between April 1 and November 30 of each year, intended to increase summer drilling activity, employment and business opportunities in northeastern British Columbia;

Deep Royalty Credit Program providing a royalty credit equal to approximately 23% of drilling and completion costs for vertical wells with a true vertical depth greater than 2,500 metres and horizontal wells with a true vertical depth greater than 2,300 metres;

Deep Re-Entry Royalty Credit Program providing royalty credits for deep re-entry wells with a true vertical depth greater than 2,300 metres and a re-entry date subsequent to December 1, 2003;

Deep Discovery Royalty Credit Program providing the lesser of a 3-year royalty holiday or 283,000,000 m^3 of royalty free gas for deep discovery wells with a true vertical depth greater than 4,000 metres whose surface locations are at least 20 kilometres away from the surface location of any well drilled into a recognized pool within the same formation with a spud date after November 30, 2003;

Coalbed Gas Royalty Reduction and Credit Program providing a royalty reduction for coalbed gas wells with average daily production less than 17,000 m^3 as well as a royalty credit for coalbed gas wells equal to $50,000 for wells drilled on Crown land and a tax credit equal to $30,000 for wells drilled on freehold land;

Marginal Royalty Reduction Program providing royalty reductions for low productivity natural gas wells with average monthly production under 25,000 m^3 during the first 12 production months and average daily production less than 23 m^3 for every metre of marginal well depth;

Ultra-Marginal Royalty Reduction Program providing additional royalty reductions for low productivity shallow natural gas wells with a true vertical depth of less than 2,500 metres in the case of vertical wells, and a total vertical depth of less than 2,300 metres in the case of a horizontal well, average monthly production under 60,000 m^3 during the first 12 production months and average daily production less than 11.5 m^3 (development wells) or 17 m^3 (exploratory wildcat wells) for every 100 metres of marginal well depth; and

Net Profit Royalty Reduction Program providing reduced initial royalty rates to facilitate the development and commercialization of technically complex resources such as coalbed gas, tight gas, shale gas and enhanced-recovery projects, with higher royalty rates applied once capital costs have been recovered.

Oil produced from an oil well that is located on either Crown or freehold land and completed in a new pool discovered subsequent to June 30, 1974 may also be exempt from the payment of a royalty for the first 36 months of production or 11,450 m^3 of production, whichever comes first.

The Government of British Columbia also maintains an Infrastructure Royalty Credit Program (the "**Infrastructure Royalty Credit Program**") which provides royalty credits for up to 50% of the cost of certain approved road construction or pipeline infrastructure projects intended to improve, or make possible, the access to new and underdeveloped oil and gas areas. In 2009, 2010 and 2011, the Government of British Columbia awarded $120 million in royalty credits to oil and gas companies under the Infrastructure Royalty Credit Program.

On August 6, 2009, the Government of British Columbia announced an oil and gas stimulus package designed to attract investment in and create economic benefits for British Columbia. The stimulus package includes four royalty initiatives related primarily to natural gas drilling and infrastructure development. British Columbia's existing Deep Royalty Credit Program was permanently amended for wells spudded after August 31, 2009 by increasing the royalty deduction on deep drilling for natural gas by 15% and extending the program to include horizontal wells drilled to depths of between 1,900 and 2,300 metres. An additional $50 million was also allocated to be distributed through the Infrastructure Royalty Credit Program to stimulate investment in oilfield-related road and pipeline construction.

Saskatchewan

In Saskatchewan, the amount payable as Crown royalty or freehold production tax in respect of oil depends on the type and vintage of oil, the quantity of oil produced in a month, the value of the oil produced and specified adjustment factors determined monthly by the provincial government. For Crown royalty and freehold production tax purposes, conventional oil is classified as "heavy oil", "southwest designated oil" or "non-heavy oil other than southwest designated oil". The conventional royalty and production tax classifications ("fourth tier oil", "third tier oil", "new oil" and "old oil") depend on the finished drilling date of a well and are applied to each of the three crude oil types slightly differently. Heavy oil is classified as third tier oil (having a finished drilling date on or after January 1, 1994 and before October 1, 2004), fourth tier oil (having a finished drilling date on or after October 1, 2002) or new oil (not classified as either third tier oil or fourth tier oil). Southwest designated oil uses the same definitions of third and fourth tier oil but new oil is defined as conventional oil produced from a horizontal well having a finished drilling date on or after February 9, 1998 and before October 1, 2002. For non-heavy oil other than southwest designated oil, the same classification is used but new oil is defined as conventional oil produced from a vertical well completed after 1973 and having a finished drilling date prior to 1994, whereas old oil is defined as conventional oil not classified as third or fourth tier oil or new oil.

Base prices are used to establish lower limits in the price-sensitive royalty structure for conventional oil. Where average wellhead prices are below the established base prices of \$100 per m^3 for third and fourth tier oil and \$50 per m^3 for new oil and old oil, base royalty rates are applied. Base royalty rates are 5% for all fourth tier oil, 10% for heavy oil that is third tier oil or new oil, 12.5% for southwest designated oil that is third tier oil or new oil, 15% for non-heavy oil other than southwest designated oil that is third tier or new oil, and 20% for old oil. Where average wellhead prices are above base prices, marginal royalty rates are applied to the proportion of production that is above the base oil price. Marginal royalty rates are 30% for all fourth tier oil, 25% for heavy oil that is third tier oil or new oil, 35% for southwest designated oil that is third tier oil or new oil, 35% for non-heavy oil other than southwest designated oil that is third tier or new oil, and 45% for old oil.

The amount payable as Crown royalty or freehold production tax in respect of natural gas production is determined by a sliding scale based on the actual price received, the quantity produced in a given month, the type of natural gas, and the vintage of the natural gas. Like conventional oil, natural gas may be classified as "non-associated gas" or "associated gas" and royalty rates are determined according to the finished drilling date of the respective well. As an incentive for the production and marketing of natural gas which may have been flared, the royalty rate on natural gas produced in association with oil is less than on non-associated natural gas. Non-associated gas is classified as new gas (having a finished drilling date before February 9, 1998 with a first production date on or after October 1, 1976), third tier gas (having a finished drilling date on or after February 9, 1998 and before October 1, 2002), fourth tier gas (having a finished drilling date on or after October 1, 2002) and old gas (not classified as either third tier, fourth tier or new gas). A similar classification is used for associated gas except that the classification of old gas is not used, the definition of fourth tier gas also includes production from oil wells with a finished drilling date prior to October 1, 2002, where the individual oil well has a gas-oil production ratio in any month of more than 3,500 m^3 of gas for every m^3 of oil, and new gas is defined as oil produced from a well with a finished drilling date before February 9, 1998 that received special approval, prior to October 1, 2002, to produce oil and gas concurrently without gas-oil ratio penalties.

On December 9, 2010, the Government of Saskatchewan enacted the *Freehold Oil and Gas Production Tax Act, 2010* replacing the existing *Freehold Oil and Gas Production Tax Act* with the intention to facilitate more efficient payment of freehold production taxes by industry. No regulations have been passed with respect to the calculation of freehold production taxes under the new legislation, although several regulations remain in force under the previous legislation.

As with conventional oil production, base prices are used to establish lower limits in the price-sensitive royalty structure for natural gas. Where average field-gate prices are below the established base prices of \$50 per thousand m^3 for third and fourth tier gas and \$35 per thousand m^3 for new gas and old gas, base royalty rates are applied. Base royalty rates are 5% for all fourth tier gas, 15% for third tier or new gas, and 20% for old gas. Where average well-head prices are above base prices, marginal royalty rates are applied to the proportion of production that is above the base gas price. Marginal royalty rates are 30% for all fourth tier gas, 35% for third tier and new gas, and 45% for old gas.

The Government of Saskatchewan currently provides a number of targeted incentive programs. These include both royalty reduction and incentive volume programs, including the following:

> *Royalty/Tax Incentive Volumes for Vertical Oil Wells Drilled on or after October 1, 2002* providing reduced Crown royalty and freehold tax rates on incentive volumes of 8,000 m^3 for deep development vertical oil wells, 4,000 m^3 for non-deep exploratory vertical oil wells and 16,000 m^3 for deep exploratory vertical oil wells (more than 1,700 metres or within certain formations);

Royalty/Tax Incentive Volumes for Exploratory Gas Wells Drilled on or after October 1, 2002 providing reduced Crown royalty and freehold tax rates on incentive volumes of 25,000,000 m^3 for qualifying exploratory gas wells;

Royalty/Tax Incentive Volumes for Horizontal Oil Wells Drilled on or after October 1, 2002 providing reduced Crown royalty and freehold tax rates on incentive volumes of 6,000 m^3 for non-deep horizontal oil wells and 16,000 m^3 for deep horizontal oil wells (more than 1,700 metres or within certain formations);

- *Royalty/Tax Incentive Volumes for Horizontal Gas Wells drilled on or after June 1, 2010 and before April 1, 2013* providing reduced Crown royalty and freehold tax rates on incentive volumes of 25,000,000 m^3 for horizontal gas wells;

Royalty/Tax Regime for Incremental Oil Produced from New or Expanded Waterflood Projects Implemented on or after October 1, 2002 treating incremental production from waterflood projects as fourth tier oil for the purposes of royalty calculation;

Royalty/Tax Regime for Enhanced Oil Recovery Projects (Excluding Waterflood Projects) Commencing prior to April 1, 2005 providing Crown royalty and freehold tax determinations based in part on the profitability of enhanced recovery projects pre- and post-payout;

Royalty/Tax Regime for Enhanced Oil Recovery Projects (Excluding Waterflood Projects) Commencing on or after April 1, 2005 providing a Crown royalty of 1% of gross revenues on enhanced oil recovery projects pre-payout and 20% post-payout and a freehold production tax of 0% on operating income from enhanced oil recovery projects pre-payout and 8% post-payout; and

Royalty/Tax Regime for High Water-Cut Oil Wells granting "third tier oil" royalty/tax rates to incremental high water-cut oil production resulting from qualifying investments made to rejuvenate eligible oil wells and/or associated facilities.

In 1975, the Government of Saskatchewan introduced a Royalty Tax Rebate ("**RTR**") as a response to the Government of Canada disallowing crown royalties and similar taxes as a deductible business expense for income tax purposes. As of January 1, 2007, the remaining balance of any unused RTR will be limited in its carry forward to seven years since the Government of Canada's initiative to reintroduce the full deduction of provincial resource royalties from federal and provincial taxable income. Saskatchewan's RTR will be wound down as a result of the Government of Canada's plan to reintroduce full deductibility of provincial resource royalties for corporate income tax purposes.

On June 22, 2011, the Government of Saskatchewan released the Upstream Petroleum Industry Associated Gas Conservation Standards which are designed to reduce emissions resulting for the flaring and venting of associated gas (the "**Associated Natural Gas Standards**"). The Associated Natural Gas Standards were jointly developed with industry and the implementation of such standards is set to commence on July 1, 2012 for new wells and facilities licensed on or after such date, and to apply to existing licensed wells and facilities on July 1, 2015.

Land Tenure

Crude oil and natural gas located in the western provinces is owned predominantly by the respective provincial governments. Provincial governments grant rights to explore for and produce oil and natural gas pursuant to leases, licences, and permits for varying terms, and on conditions set forth in provincial legislation including requirements to perform specific work or make payments. Oil and natural gas located in such provinces can also be privately owned and rights to explore for and produce such oil and natural gas are granted by lease on such terms and conditions as may be negotiated.

Each of the provinces of Alberta, British Columbia and Saskatchewan has implemented legislation providing for the reversion to the Crown of mineral rights to deep, non-productive geological formations at the conclusion of the primary term of a lease or license. On March 29, 2007, British Columbia's policy of deep rights reversion was expanded for new leases to provide for the reversion of both shallow and deep formations that cannot be shown to be capable of production at the end of their primary term.

Alberta also has a policy of "shallow rights reversion" which provides for the reversion to the Crown of mineral rights to shallow, non-productive geological formations for all leases and licenses. For leases and licenses issued subsequent to January 1, 2009, shallow rights reversion will be applied at the conclusion of the primary term of the lease or license. Holders of leases or licences that have been continued indefinitely prior to January 1, 2009 will receive a notice regarding the reversion of the shallow rights, which will be implemented three years from the date of the notice. Leases and licences that were granted prior to January 1, 2009 but continued after that date are not subject to shallow rights reversion until they reach the end of their primary term and are continued (at which time deep rights reversion will be applied); thereafter, the holders of such agreements will be served with shallow rights reversion notices based on vintage and location similar to leases and licences that were already continued as of January 1, 2009. The order in which these agreements will receive reversion notices will depend on their vintage and location, and the Government of Alberta had anticipated that the receipt of reversion notices for older leases and licenses would commence in April 2011. However, on April 14, 2011, the Government of Alberta announced it was deferring serving shallow rights reversion notices and will revisit the decision in spring 2012.

Environmental Regulation

The oil and natural gas industry is currently subject to environmental regulations pursuant to a variety of provincial and federal legislation, all of which is subject to governmental review and revision from time to time. Such legislation provides for restrictions and prohibitions on the release or emission of various substances produced in association with certain oil and gas industry operations, such as sulphur dioxide and nitrous oxide. In addition, such legislation requires that well and facility sites be abandoned and reclaimed to the satisfaction of provincial authorities. Compliance with such legislation can require significant expenditures and a breach of such requirements may result in suspension or revocation of necessary licenses and authorizations, civil liability for pollution damage, and the imposition of material fines and penalties.

In December, 2008, the Government of Alberta released a new land use policy for surface land in Alberta, the Alberta Land Use Framework (the "**ALUF**"). The ALUF sets out an approach to manage public and private land use and natural resource development in a manner that is consistent with the long-term economic, environmental and social goals of the province. It calls for the development of region-specific land use plans in order to manage the combined impacts of existing and future land use within a specific region and the incorporation of a cumulative effects management approach into such plans.

The *Alberta Land Stewardship Act* (the "**ALSA**") was proclaimed in force in Alberta on October 1, 2009 and provides the legislative authority for the Government of Alberta to implement the policies contained in the ALUF. Regional plans established pursuant to the ALSA will be deemed to be legislative instruments equivalent to regulations and will be binding on the Government of Alberta and provincial regulators, including those governing the oil and gas industry. In the event of a conflict or inconsistency between a regional plan and another regulation, regulatory instrument or statutory consent, the regional plan will prevail. Further, the ALSA requires local governments, provincial departments, agencies and administrative bodies or tribunals to review their regulatory instruments and make any appropriate changes to ensure that they comply with an adopted regional plan. The ALSA also contemplates the amendment or extinguishment of previously issued statutory consents such as regulatory permits, leases, licenses, approvals and authorizations for the purpose of achieving or maintaining an objective or policy resulting from the implementation of a regional plan. Among the measures to support the goals of the regional plans contained in the ALSA are conservation easements, which can be granted for the protection, conservation and enhancement of land; and conservation directives, which are explicit declarations contained in a regional plan to set aside specified lands in order to protect, conserve, manage and enhance the environment.

On August 29, 2011 the Government of Alberta released a revised draft of the Lower Athabasca Regional Plan (the "**Revised LARP**") updating its prior draft of April 5, 2011 (the "**Draft LARP**"). The Revised LARP, while establishing several conservation areas of the Athabasca region, has changed the boundaries of certain conservation areas outlined in the Draft LARP with the result that fewer oil sands leases appear to be impacted. Consistent with the Draft LARP, as the intention of the Revised LARP is to manage the areas to minimize or prevent new land disturbance, activities associated with oil sands development are considered incompatible with the intent to manage such conservation areas. However, references to the cancellation of existing tenures have been removed from the Revised LARP and the Revised LARP now contemplates that the conservation areas will be created pursuant to existing legislation rather than the previously contemplated regulations. Existing conventional petroleum and natural gas rights will not be affected, although the Revised LARP raises some question as to whether new conventional leases and licenses will be granted in the conservation areas in the future. The planning process is also underway for a regional plan for the South Saskatchewan Region.

Climate Change Regulation

Federal

In December 2002, the Government of Canada ratified the Kyoto Protocol ("**Kyoto Protocol**"), which requires a reduction in greenhouse gas ("**GHG**") emissions by signatory countries between 2008 and 2012. The Kyoto Protocol officially came into force on February 16, 2005 although on December 12, 2011 Canada formally withdrew from the Kyoto Protocol.

On April 26, 2007, the Government of Canada released "Turning the Corner: An Action Plan to Reduce Greenhouse Gases and Air Pollution" (the "**Action Plan**") which set forth a plan for regulations to address both GHGs and air pollution. An update to the Action Plan, "Turning the Corner: Regulatory Framework for Industrial Greenhouse Gas Emissions" was released on March 10, 2008 (the "**Updated Action Plan**"). The Updated Action Plan outlines emissions intensity-based targets which will be applied to regulated sectors on either a facility-specific, sector-wide or company-by-company basis. Facility-specific targets apply to the upstream oil and gas, oil sands, petroleum refining and natural gas pipelines sectors. Unless a minimum regulatory threshold applies, all facilities within a regulated sector will be subject to the emissions intensity targets.

The Updated Action Plan makes a distinction between "Existing Facilities" and "New Facilities". For Existing Facilities, the Updated Action Plan requires an emissions intensity reduction of 18% below 2006 levels by 2010 followed by a continuous annual emissions intensity improvement of 2%. "New Facilities" are defined as facilities beginning operations in 2004 and include both greenfield facilities and major facility expansions that (i) result in a 25% or greater increase in a facility's physical capacity, or (ii) involve significant changes to the processes of the facility. New Facilities will be given a 3-year grace period during which no emissions intensity reductions will be required. Targets requiring an annual 2% emissions intensity reduction will begin to apply in the fourth year of commercial operation of a New Facility. Further, emissions intensity targets for New Facilities will be based on a cleaner fuel standard to encourage continuous emissions intensity reductions over time. The method of applying this cleaner fuel standard has not yet been determined. In addition, the Updated Action Plan indicates that targets for the adoption of carbon capture and storage ("**CCS**") technologies will be developed for oil sands in-situ facilities, upgraders and coal-fired power generators that begin operations in 2012 or later. These targets will become operational in 2018, although the exact nature of the targets has not yet been determined.

Given the large number of small facilities within the upstream oil and gas and natural gas pipeline sectors, facilities within these sectors will only be subject to emissions intensity targets if they meet certain minimum emissions thresholds. That threshold will be (i) 50,000 tonnes of CO_2 equivalents per facility per year for natural gas pipelines; (ii) 3,000 tonnes of CO_2 equivalents per facility per year for the upstream oil and gas facility; and (iii) 10,000 boe/d/company. These regulatory thresholds are significantly lower than the regulatory threshold in force in Alberta, discussed below. In all other sectors governed by the Updated Action Plan, all facilities will be subject to regulation.

Four separate compliance mechanisms are provided for in the Updated Action Plan in respect of the above targets:

(a) Regulated entities will be able to use Technology Fund contributions to meet their emissions intensity targets. The contribution rate for Technology Fund contributions will increase over time, beginning at $15 per tonne of CO_2 equivalent for the 2010 to 2012 period, rising to $20 in 2013, and thereafter increasing at the nominal rate of GDP growth. Maximum contribution limits will also decline from 70% in 2010 to 0% in 2018. Monies raised through contributions to the Technology Fund will be used to invest in technology to reduce GHG emissions. Alternatively, regulated entities may be able to receive credits for investing in large-scale and transformative projects at the same contribution rate and under similar requirements as described above.

(b) The offset system is intended to encourage emissions reductions from activities outside of the regulated sphere, allowing non-regulated entities to participate in and benefit from emissions reduction activities. In order to generate offset credits, project proponents must propose and receive approval for emissions reduction activities that will be verified before offset credits will be issued to the project proponent. Those credits can then be sold to regulated entities for use in compliance or non-regulated purchasers that wish to either purchase the offset credits for cancellation or banking for future use or sale.

(c) Under the Updated Action Plan, regulated entities were able to purchase credits created through the Clean Development Mechanism of the Kyoto Protocol which facilitates investment by developed nations in emissions-reduction projects in developing countries. The purchase of such Emissions Reduction Credits will be restricted to 10% of each firm's regulatory obligation, with the added restriction that credits generated through forest sink projects will not be available for use in complying with the Canadian regulations. However, with the recent withdrawal from the Kyoto Protocol, the future use of this mechanism may not occur.

(d) Finally, a one-time credit of up to 15 million tonnes worth of emissions credits will be awarded to regulated entities for emissions reduction activities undertaken between 1992 and 2006. These credits will be both tradable and bankable.

From December 7 to 18, 2009, government leaders and representatives met in Copenhagen, Denmark and agreed to the Copenhagen Accord, which reinforces the commitment to reducing GHG emissions contained in the Kyoto Protocol and promises funding to help developing countries mitigate and adapt to climate change. Another meeting of government leaders and representatives in 2010 resulted in the Cancun Agreements wherein developed countries committed to additional measures to help developing countries deal with climate change. Neither the Copenhagen Accord nor the Cancun Agreements establish binding GHG emissions reduction targets. In response to the Copenhagen Accord, the Government of Canada indicated that it will seek to achieve a 17% reduction in GHG emissions from 2005 levels by 2020.

Although draft regulations for the implementation of the Updated Action Plan were intended to become binding on January 1, 2010, only draft regulations pertaining to carbon dioxide emissions from coal-fired generation of electricity have been proposed to date. Further, representatives of the Government of Canada have indicated that the proposals contained in the Updated Action Plan will be modified to ensure consistency with the direction ultimately taken by the United States with respect to GHG emissions regulation. As a result, it is unclear to what extent, if any; the proposals contained in the Updated Action Plan will be implemented.

The United States Environmental Protection Agency (the "**EPA**") has indicated its intention to impose GHG emissions standards for fossil fuel-fired power plants by specifying that it will issue final regulations by May 26, 2012, and with respect to refineries, specifying that it will issue proposed regulations by December 10, 2011 and finalized regulations by November 10, 2012. The EPA did not meet the December 10, 2011 deadline and it is unclear whether the EPA will also miss the finalized regulations deadline.

Alberta

Alberta enacted the *Climate Change and Emissions Management Act* (the "**CCEMA**") on December 4, 2003, amending it through the *Climate Change and Emissions Management Amendment Act* which received royal assent on November 4, 2008. The CCEMA is based on an emissions intensity approach similar to the Updated Action Plan and aims for a 50% reduction from 1990 emissions relative to GDP by 2020.

Alberta facilities emitting more than 100,000 tonnes of GHGs a year are subject to compliance with the CCEMA. Similar to the Updated Action Plan, the CCEMA and the associated *Specified Gas Emitters Regulation* make a distinction between "Established Facilities" and "New Facilities". Established Facilities are defined as facilities that completed their first year of commercial operation prior to January 1, 2000 or that have completed eight or more years of commercial operation. Established Facilities are required to reduce their emissions intensity to 88% of their baseline for 2008 and subsequent years, with their baseline being established by the average of the ratio of the total annual emissions to production for the years 2003 to 2005. New Facilities are defined as facilities that completed their first year of commercial operation on December 31, 2000, or a subsequent year, and have completed less than eight years of commercial operation, or are designated as New Facilities in accordance with the *Specified Gas Emitters Regulation*. New Facilities are required to reduce their emissions intensity by 2% from baseline in the fourth year of commercial operation, 4% of baseline in the fifth year, 6% of baseline in the sixth year, 8% of baseline in the seventh year, and 10% of baseline in the eighth year. Unlike the Updated Action Plan, the CCEMA does not contain any provision for continuous annual improvements in emissions intensity reductions beyond those stated above.

The CCEMA contains compliance mechanisms that are similar to the Updated Action Plan. Regulated emitters can meet their emissions intensity targets by contributing to the Climate Change and Emissions Management Fund (the "**Fund**") at a rate of $15 per tonne of CO_2 equivalent. Unlike the Updated Action Plan, CCEMA contains no provisions for an increase to this contribution rate. Emissions credits can be purchased from regulated emitters that have reduced their emissions below the 100,000 tonne threshold or non-regulated emitters that have generated emissions offsets through activities that result in emissions reductions in accordance with established protocols published by the Government of Alberta.

On December 2, 2010, the Government of Alberta passed the *Carbon Capture and Storage Statutes Amendment Act, 2010*, which deemed the pore space underlying all land in Alberta to be, and to have always been, the property of the Crown and provided for the assumption of long-term liability for carbon sequestration projects by the Crown, subject to the satisfaction of certain conditions.

British Columbia

In February, 2008, British Columbia announced a revenue-neutral carbon tax that took effect July 1, 2008. The tax is consumption-based and applied at the time of retail sale or consumption of virtually all fossil fuels purchased or used in British Columbia. The current tax level is $25 per tonne of CO_2 equivalent. It is scheduled to increase to $30 per tonne of CO_2 equivalent on July 31, 2012. In order to make the tax revenue-neutral, British Columbia has implemented tax credits and reductions in order to offset the tax revenues that the Government of British Columbia would otherwise receive from the tax.

On April 3, 2008, British Columbia introduced the *Greenhouse Gas Reduction (Cap and Trade) Act* (the "**Cap and Trade Act**") which received royal assent on May 29, 2008 and partially came into force by regulation of the Lieutenant Governor in Council. Unlike the emissions intensity approach taken by the federal government and the Government of Alberta, the Cap and Trade Act establishes an absolute cap on GHG emissions. Although more specific details of British Columbia's cap and trade plan have not yet been finalized, on January 1, 2010, new reporting regulations came into force requiring all British Columbia facilities emitting over 10,000 tonnes of CO_2 equivalents per year to begin reporting their emissions. Facilities reporting emissions greater than 25,000 tonnes of CO_2 equivalents per year are required to have their emissions reports verified by a third party. Regulations pertaining to proposed offsets and emissions trading are currently in the consultation stage.

Saskatchewan

On May 11, 2009, the Government of Saskatchewan announced *The Management and Reduction of Greenhouse Gases Act* (the "**MRGGA**") to regulate GHG emissions in the province. The MRGGA received Royal Assent on May 20, 2010 and will come into force on proclamation. Regulations under the MRGGA have also yet to be proclaimed, but draft versions indicate that Saskatchewan will adopt the goal of a 20% reduction in GHG emissions from 2006 levels by 2020 and permit the use of pre-certified investment credits, early action credits and emissions offsets in compliance, similar to both the federal and Alberta climate change initiatives. It remains unclear whether the scheme implemented by the MRGGA will be based on emissions intensity or an absolute cap on emissions.

RISK FACTORS

Investors should carefully consider the risk factors set out below and consider all other information contained herein and in the Corporation's other public filings before making an investment decision.

Exploration, Development and Production Risks

Oil and natural gas operations involve many risks that even a combination of experience, knowledge and careful evaluation may not be able to overcome. The long-term commercial success of the Corporation depends on its ability to find, acquire, develop and commercially produce oil and natural gas reserves. Without the continual addition of new reserves, any existing reserves the Corporation may have at any particular time, and the production therefrom will decline over time as such existing reserves are exploited. A future increase in the Corporation's reserves will depend not only on its ability to explore and develop any properties it may have from time to time, but also on its ability to select and acquire suitable producing properties or prospects. No assurance can be given that the Corporation will be able to continue to locate satisfactory properties for acquisition or participation therein. Moreover, if such acquisitions or participations are identified, management of the Corporation may determine that current markets, terms of acquisition and participation or pricing conditions make such acquisitions or participations uneconomic. There is no assurance that further commercial quantities of oil and natural gas will be discovered or acquired by the Corporation.

Future oil and natural gas exploration may involve unprofitable efforts, not only from dry wells, but also from wells that are productive but do not produce sufficient petroleum substances to return a profit after drilling, completing (including hydraulic fracturing), operating and other costs. Completion of a well does not assure a profit on the investment or recovery of drilling, completion and operating costs. Drilling hazards or environmental damage could greatly increase the cost of operations, and various field operating conditions may adversely affect the production from successful wells. These conditions include delays in obtaining governmental approvals or consents, shut-ins of connected wells resulting from extreme weather conditions, insufficient storage or transportation capacity or other geological and mechanical conditions. While diligent well supervision and effective maintenance operations can contribute to maximizing production rates over time, production delays and declines from normal field operating conditions cannot be eliminated and can be expected to adversely affect revenue and cash flow levels to varying degrees.

Oil and natural gas exploration, development and production operations are subject to all the risks and hazards typically associated with such operations, including fire, explosion, blowouts, cratering, sour gas releases, spills or other environmental hazards, each of which could result in substantial damage to oil and natural gas wells, production facilities, other property and the environment or personal injury. In particular, the Corporation may explore for and produce sour natural gas in certain areas. An unintentional leak of sour natural gas could result in personal injury, loss of life or damage to property and may necessitate an evacuation of populated areas, all of which could result in liability to the Corporation. Oil and natural gas production operations are also subject to all the risks typically associated with such operations, including encountering unexpected formations or pressures, premature decline of reservoirs and the invasion of water into producing formations. Losses resulting from the occurrence of any of these risks may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. In accordance with industry practice, the Corporation is not fully insured against all risks, nor are all risks insurable. Although the Corporation maintains liability insurance in an amount that it considers consistent with industry practice, the nature of certain risks is such that liabilities could exceed policy limits or not be covered, in either event the Corporation could incur significant costs.

Global Financial Crisis

Recent market events and conditions, including disruptions in the international credit markets and other financial systems and the American and European sovereign debt levels have caused significant volatility in commodity prices. These conditions have caused a decrease in confidence in the global credit and financial markets and have created a climate of greater volatility, less liquidity, widening of credit spreads, a lack of price transparency, increased credit losses and tighter credit conditions. Notwithstanding various actions by governments, concerns about the general condition of the capital markets, financial instruments, banks, investment banks, insurers and other financial institutions caused the broader credit markets to further deteriorate and stock markets to decline substantially. This volatility may in the future affect the Corporation's ability to obtain equity or debt financing on acceptable terms.

Prices, Markets and Marketing

The marketability and price of oil and natural gas that may be acquired or discovered by the Corporation is and will continue to be affected by numerous factors beyond its control. The Corporation's ability to market its oil and natural gas may depend upon its ability to acquire space on pipelines that deliver natural gas to commercial markets. The Corporation may also be affected by deliverability uncertainties related to the proximity of its reserves to pipelines and processing and storage facilities and operational problems affecting such pipelines and facilities as well as extensive government regulation relating to price, taxes, royalties, land tenure, allowable production, the export of oil and natural gas and many other aspects of the oil and natural gas business.

The prices of oil and natural gas prices may be volatile and subject to fluctuation. Any material decline in prices could result in a reduction of the Corporation's net production revenue. The economics of producing from some wells may change as a result of lower prices, which could result in reduced production of oil or natural gas and a reduction in the volumes of the Corporation's reserves. The Corporation might also elect not to produce from certain wells at lower prices. All of these factors could result in a material decrease in the Corporation's expected net production revenue and a reduction in its oil and natural gas acquisition, development and exploration activities. Prices for oil and natural gas are subject to large fluctuations in response to relatively minor changes in the supply of and demand for oil and natural gas, market uncertainty and a variety of additional factors beyond the control of the Corporation. These factors include economic conditions, in the United States, Canada and Europe, the actions of OPEC, governmental regulation, political stability in the Middle East, Northern Africa and elsewhere, the foreign supply of oil and natural gas, risks of supply disruption, the price of foreign imports and the availability of alternative fuel sources. Any substantial and extended decline in the price of oil and natural gas would have an adverse effect on the Corporation's carrying value of its reserves, borrowing capacity, revenues, profitability and cash flows from operations and may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Oil and natural gas prices are expected to remain volatile for the near future as a result of market uncertainties over the supply and the demand of these commodities due to the current state of the world economies, OPEC actions, and sanctions imposed on certain oil producing nations by other countries and the ongoing credit and liquidity concerns. Volatile oil and natural gas prices make it difficult to estimate the value of producing properties for acquisitions and often cause disruption in the market for oil and natural gas producing properties, as buyers and sellers have difficulty agreeing on such value. Price volatility also makes it difficult to budget for and project the return on acquisitions and development and exploitation projects.

Market Price of Common Shares

The trading price of securities of oil and natural gas issuers is subject to substantial volatility. This volatility is often based on factors both related and unrelated to the financial performance or prospects of the issuers involved. The market price of the Common Shares of the Corporation could be subject to significant fluctuations in response to variations in the Corporation's operating results, financial condition, liquidity and other internal factors. Factors that could affect the market price of the Common Shares of the Corporation that are unrelated to the Corporation's performance include domestic and global commodity prices and market perceptions of the attractiveness of particular industries. The price at which the Common Shares of the Corporation will trade cannot be accurately predicted.

Failure to Realize Anticipated Benefits of Acquisitions and Dispositions

The Corporation considers acquisitions and dispositions of businesses and assets in the ordinary course of business. Achieving the benefits of acquisitions depends in part on successfully consolidating functions and integrating operations and procedures in a timely and efficient manner as well as the Corporation's ability to realize the anticipated growth opportunities and synergies from combining the acquired businesses and operations with those of the Corporation. The integration of acquired businesses may require substantial management effort, time and resources and may divert management's focus from other strategic opportunities and operational matters.

Management continually assesses the value and contribution of services provided and assets required to provide such services. In this regard, non-core assets may be periodically disposed of, so that the Corporation can focus its efforts and resources more efficiently. Depending on the state of the market for such non-core assets, certain non-core assets of the Corporation, if disposed of, could be expected to realize less than their carrying value on the financial statements of the Corporation.

Operational Dependence

Other companies operate some of the assets in which the Corporation has an interest. As a result, the Corporation has limited ability to exercise influence over the operation of those assets or their associated costs, which could adversely affect the Corporation's financial performance. The Corporation's return on assets operated by others therefore depends upon a number of factors that may be outside of the Corporation's control, including the timing and amount of capital expenditures, the operator's expertise and financial resources, the approval of other participants, the selection of technology and risk management practices.

Project Risks

The Corporation manages a variety of small and large projects in the conduct of its business. Project delays may delay expected revenues from operations. Significant project cost over-runs could make a project uneconomic. The Corporation's ability to execute projects and market oil and natural gas depends upon numerous factors beyond the Corporation's control, including:

- the availability of processing capacity;
- the availability and proximity of pipeline capacity;
- the availability of storage capacity;
- the availability of, and the ability to acquire, water supplies needed for drilling and hydraulic fracturing, or the Corporation's ability to dispose of water used or removed from strata at a reasonable cost and within applicable environmental regulations;
- the supply of and demand for oil and natural gas;
- the availability of alternative fuel sources;
- the effects of inclement weather;
- the availability of drilling and related equipment;
- unexpected cost increases;
- accidental events;
- currency fluctuations;
- changes in regulations;
- the availability and productivity of skilled labour; and
- the regulation of the oil and natural gas industry by various levels of government and governmental agencies.

Because of these factors, the Corporation could be unable to execute projects on time, on budget or at all, and may not be able to effectively market the oil and natural gas that it produces.

Gathering and Processing Facilities and Pipeline Systems

The Corporation delivers its products through gathering, processing and pipeline systems some of which it does not own. The amount of oil and natural gas that the Corporation can produce and sell is subject to the accessibility, availability, proximity and capacity of these gathering, processing and pipeline systems. The lack of availability of capacity in any of the gathering, processing and pipeline systems, and in particular the processing facilities, could result in the Corporation's inability to realize the full economic potential of its production or in a reduction of the price offered for the Corporation's production. Any significant change in market factors or other conditions affecting these infrastructure systems and facilities, as well as any delays in constructing new infrastructure systems and facilities could harm the Corporation's business and, in turn, the Corporation's financial condition, results of operations and cash flows.

A portion of the Corporation's production may, from time to time, be processed through facilities owned by third parties and over which the Corporation does not have control. From time to time these facilities may discontinue or decrease operations either as a result of normal servicing requirements or as a result of unexpected events. A discontinuation or decrease of operations could materially adversely affect the Corporation's ability to process its production and to deliver the same for sale.

Competition

The petroleum industry is competitive in all its phases. The Corporation competes with numerous other entities in the search for, and the acquisition of, oil and natural gas properties and in the marketing of oil and natural gas. 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 increase its reserves in the future will depend not only on its ability to explore and develop its present properties, but also on its ability to select and acquire other 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 and storage. Competition may also be presented by alternate fuel sources.

Regulatory

Oil and natural gas operations (exploration, production, pricing, marketing and transportation) are subject to extensive controls and regulations imposed by various levels of government, which may be amended from time to time. See "Industry Conditions". Governments may regulate or intervene with respect to exploration and production activities, prices, taxes, royalties and the exportation of oil and natural gas. Such regulations may be changed from time to time in response to economic or political conditions. The implementation of new regulations or the modification of existing regulations affecting the oil and natural gas industry could reduce demand for crude oil and natural gas and increase the Corporation's costs, either of which may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. In order to conduct oil and natural gas operations, the Corporation will require licenses from various governmental authorities. There can be no assurance that the Corporation will be able to obtain all of the licenses and permits that may be required to conduct operations that it may wish to undertake.

Hydraulic Fracturing

Hydraulic fracturing involves the injection of water, sand and small amounts of additives under pressure into rock formations to stimulate hydrocarbon (oil and natural gas) production. The use of hydraulic fracturing is being used to produce commercial quantities of oil and natural gas from reservoirs that were previously unproductive. Any new laws, regulations or permitting requirements regarding hydraulic fracturing could lead to operational delays, increased operating costs or third party or governmental claims, and could increase the Corporation's costs of compliance and doing business as well as delay the development of oil and natural gas resources from shale formations which are not commercial without the use of hydraulic fracturing. Restrictions on hydraulic fracturing could also reduce the amount of oil and natural gas that the Corporation is ultimately able to produce from its reserves.

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 of applicable environmental legislation 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 potentially increased capital expenditures and operating costs. The discharge of oil, natural gas or other pollutants into the air, soil or water may give rise to liabilities to governments and third parties and may require the Corporation to incur costs to remedy such discharge. Although the Corporation believes that it will be in material compliance with current applicable environmental regulations, no assurance can be given that environmental laws will not result in a curtailment of production or a material increase in the costs of production, development or exploration activities or otherwise have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Climate Change

The Corporation's exploration and production facilities and other operations and activities emit greenhouse gases and require the Corporation to comply with greenhouse gas emissions legislation in Alberta and British Columbia or that may be enacted in other provinces. The Corporation may also be required comply with the regulatory scheme for greenhouse gas emissions ultimately adopted by the federal government, which regulations are expected to be consistent with the regulatory scheme for greenhouse gas emissions adopted by the United States. The direct or indirect costs of these regulations may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. The future implementation or modification of greenhouse gases regulations, whether to meet the limits regulated by the Copenhagen Accord or as otherwise determined, could have a material impact on the nature of oil and natural gas operations, including those of the Corporation. Given the evolving nature of the debate related to climate change and the control of greenhouse gases and resulting requirements, it is not possible to predict the impact on the Corporation and its operations and financial condition. See "Industry Conditions – Climate Change Regulation".

Variations in Foreign Exchange Rates and Interest Rates

World oil and natural gas prices are quoted in United States dollars and the price received by Canadian producers is therefore affected by the Canadian/U.S. dollar exchange rate, which will fluctuate over time. In recent years, the Canadian dollar has increased materially in value against the United States dollar. Material increases in the value of the Canadian dollar negatively impact the Corporation's production revenues. Future Canadian/United States exchange rates could accordingly impact the future value of the Corporation's reserves as determined by independent evaluators.

To the extent that the Corporation engages in risk management activities related to foreign exchange rates, there is a credit risk associated with counterparties with which the Corporation may contract.

An increase in interest rates could result in a significant increase in the amount the Corporation pays to service debt, which could negatively impact the market price of the of the Corporation.

Substantial Capital Requirements

The Corporation anticipates making substantial capital expenditures for the acquisition, exploration, development and production of oil and natural gas reserves in the future. As future capital expenditures will be financed out of cash generated from operations, borrowings and possible future equity sales, the Corporation's ability to do so is dependent on, among other factors, the overall state of the capital markets, the Corporation's credit rating (if applicable), interest rates, tax burden due to new tax laws and investor appetite for investments in the energy industry and the Corporation's securities in particular. Further, if the Corporation's revenues or reserves decline, it may not have access to the capital necessary to undertake or complete future drilling programs. 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. The inability of the Corporation to access sufficient capital for its operations could have a material adverse effect on the Corporation's business financial condition, results of operations and prospects.

Additional Funding Requirements

The Corporation's cash flow from its reserves may not be sufficient to fund its ongoing activities at all times and from time to time, the Corporation may require additional financing in order to carry out its oil and natural gas acquisition, exploration and development activities. As a result of the global economic volatility, the Corporation, along with many other oil and natural gas entities, may, from time to time, have restricted access to capital and increased borrowing costs. Failure to obtain such financing on a timely basis could cause the Corporation to forfeit its interest in certain properties, miss certain acquisition opportunities and reduce or terminate its operations. If the Corporation's revenues from its reserves decrease as a result of lower oil and natural gas prices or otherwise, it will affect the Corporation's ability to expend the necessary capital to replace its reserves or to maintain its production. To the extent that external sources of capital become limited or unavailable or available on onerous terms, the Corporation's ability to make capital investments and maintain existing assets may be impaired, and its assets, liabilities, business, financial condition and results of operations may be materially and adversely affected as a result. In addition, the future development of the Corporation's petroleum properties may require additional financing and there are no assurances that such financing will be available or, if available, will be available upon acceptable terms. Failure to obtain any financing necessary for the Corporation's capital expenditure plans may result in a delay in development or production on the Corporation's properties.

Credit Facility Arrangements

The Corporation currently has a credit facility and the amount authorized thereunder is dependent on the borrowing base determined by its lenders. The Corporation is required to comply with covenants under its credit facility which may, in certain cases, include certain financial ratio tests, which from time to time either affect the availability, or price, of additional funding and in the event that the Corporation does not comply therewith the Corporation's access to capital could be restricted or repayment could be required. The failure of the Corporation to comply with such covenants, which may be affected by events beyond the Corporation's control, could result in the default under the Corporation's credit facility which could result in the Corporation being required to repay amounts owing thereunder. Even if the Corporation is able to obtain new financing, it may not be on commercially reasonable terms or terms that are acceptable to the Corporation. If the Corporation is unable to repay amounts owing, the lenders under the credit facility could proceed to foreclose or otherwise realize upon the collateral granted to them to secure the indebtedness. The acceleration of the Corporation's indebtedness under one agreement may permit acceleration of indebtedness under other agreements that contain cross default or cross-acceleration provisions. In addition, the Corporation's credit facility may, from time to time, impose operating and financial restrictions on the Corporation that could include restrictions on, the payment of dividends, repurchase or making of other distributions with respect to the Corporation's securities, incurring of additional indebtedness, provision of guarantees, the assumption of loans, making of capital expenditures, entering into of amalgamations, mergers, take-over bids or disposition of assets, among others.

The Corporation's borrowing base is determined and re-determined by the Corporation's lenders based on the Corporation's reserves, commodity prices, applicable discount rate and other factors as determined by the Corporation's lenders. A material decline in commodity prices could reduce the Corporation's borrowing base, therefore reducing the funds available to the Corporation under the credit facility which could result in a portion, or all, of the Corporation's bank indebtedness be required to be repaid.

Issuance of Debt

From time to time the Corporation may enter into transactions to acquire assets or shares of other organizations. These transactions may be financed in whole or in part with debt, which may increase the Corporation's debt levels above industry standards for oil and natural gas companies of similar size. Depending on future exploration and development plans, the Corporation may require additional debt financing that may not be available or, if available, may not be available on favourable terms. Neither the Corporation's articles nor its by-laws limit the amount of indebtedness that the Corporation may incur. The level of the Corporation's indebtedness from time to time, could impair the Corporation's ability to obtain additional financing on a timely basis to take advantage of business opportunities that may arise.

Hedging

From time to time the Corporation may enter into agreements to receive fixed prices on its oil and natural gas production to offset the risk of revenue losses if commodity prices decline. However, to the extent that the Corporation engages in price risk management activities to protect itself from commodity price declines, it may also be prevented from realizing the full benefits of price increases above the levels of the derivative instruments used to manage price risk. In addition, the Corporation's hedging arrangements may expose it to the risk of financial loss in certain circumstances, including instances in which:

- production falls short of the hedged volumes;
- there is a widening of price-basis differentials between delivery points for production and the delivery point assumed in the hedge arrangement;
- the counterparties to the hedging arrangements or other price risk management contracts fail to perform under those arrangements; or
- a sudden unexpected event materially impacts oil and natural gas prices.

Similarly, from time to time the Corporation may enter into agreements to fix the exchange rate of Canadian to United States dollars in order to offset the risk of revenue losses if the Canadian dollar increases in value compared to the United States dollar; however, if the Canadian dollar declines in value compared to the United States dollar, the Corporation will not benefit from the fluctuating exchange rate.

Availability of Drilling Equipment and Access

Oil and natural gas exploration and development activities are dependent on the availability of drilling and related equipment (typically leased from third parties) in the particular areas where such activities will be conducted. Demand for such limited equipment or access restrictions may affect the availability of such equipment to the Corporation and may delay exploration and development activities.

Title to Assets

Although title reviews may be conducted prior to the purchase of 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 Corporation's claim which may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. There may be valid challenges to title, or proposed legislative changes which affect title, to the oil and natural gas properties the Corporation controls that, if successful or made into law, could impair the Corporation's activities on them and result in a reduction of the revenue received by the Corporation.

Reserve Estimates

There are numerous uncertainties inherent in estimating quantities of oil, natural gas and natural gas liquids reserves and the future cash flows attributed to such reserves. The reserve and associated cash flow information set forth herein are estimates only. In general, estimates of economically recoverable oil and natural gas reserves and the future net cash flows therefrom are based upon a number of variable factors and assumptions, such as historical production from the properties, production rates, ultimate reserve recovery, 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 materially from actual results. For those reasons, estimates of the economically recoverable oil and natural gas reserves attributable to any particular group of properties, classification of such reserves based on risk of recovery and estimates of future net revenues associated with reserves prepared by different engineers, or by the same engineers at different times may vary. The Corporation's actual production, revenues, taxes and development and operating expenditures with respect to its reserves will vary from estimates thereof and such variations could be material.

Estimates of proved reserves that may be developed and produced in the future are often based upon volumetric calculations and upon analogy to similar types of reserves rather than actual production history. Recovery factors and drainage areas were estimated by experience and analogy to similar producing pools. Estimates based on these methods are generally less reliable than those based on actual production history. Subsequent evaluation of the same reserves based upon production history and production practices will result in variations in the estimated reserves and such variations could be material.

In accordance with applicable securities laws, the Corporation's independent reserves evaluator has used forecast prices and costs in estimating the reserves and future net cash flows as summarized herein. Actual future net cash flows will be affected by other factors, such as actual production levels, supply and demand for oil and natural gas, curtailments or increases in consumption by oil and natural gas purchasers, changes in governmental regulation or taxation and the impact of inflation on costs.

Actual production and cash flows derived from the Corporation's oil and natural gas reserves will vary from the estimates contained in the reserve evaluation, and such variations could be material. The reserve evaluation is based in part on the assumed success of activities the Corporation intends to undertake in future years. The reserves and estimated cash flows to be derived therefrom contained in the reserve evaluation will be reduced to the extent that such activities do not achieve the level of success assumed in the reserve evaluation. The reserve evaluation is effective as of a specific effective date and has not been updated and thus does not reflect changes in the Corporation's reserves since that date.

Insurance

The Corporation's involvement in the exploration for and development of oil and natural gas properties may result in the Corporation becoming subject to liability for pollution, blow outs, leaks of sour natural gas, property damage, personal injury or other hazards. Although the Corporation maintains insurance in accordance with industry standards to address certain of these risks, such insurance has limitations on liability and may not be sufficient to cover the full extent of such liabilities. In addition, certain risks are not, in all circumstances, insurable 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 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, may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Geo-Political Risks

The marketability and price of oil and natural gas that may be acquired or discovered by the Corporation is and will continue to be affected by political events throughout the world that cause disruptions in the supply of oil. Conflicts, or conversely peaceful developments, arising in the Middle East, North Africa and other areas of the world have a significant impact on the price of oil and natural gas. Any particular event could result in a material decline in prices and therefore result in a reduction of the Corporation's net production revenue.

In addition, the Corporation's oil and natural gas properties, wells and facilities could be subject to a terrorist attack. If any of the Corporation's properties, wells or facilities are the subject of terrorist attack it may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. The Corporation does not have insurance to protect against the risk from terrorism.

Dilution

The Corporation may make future acquisitions or enter into financings or other transactions involving the issuance of securities of the Corporation which may be dilutive.

Management of Growth

The Corporation may be subject to growth-related risks including capacity constraints and pressure on its internal systems and controls. The ability of the Corporation to manage growth effectively will require it to continue to implement and improve its operational and financial systems and to expand, train and manage its employee base. The inability of the Corporation to deal with this growth may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Expiration of Licences and Leases

The Corporation's properties are held in the form of licences and leases and working interests in licences and leases. If the Corporation or the holder of the licence or lease fails to meet the specific requirement of a licence or lease, the licence or lease may terminate or expire. There can be no assurance that any of the obligations required to maintain each licence or lease will be met. The termination or expiration of the Corporation's licences or leases or the working interests relating to a licence or lease may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Dividends

The Corporation has not paid any dividends on its outstanding shares. Payment of dividends in the future will be dependent on, among other things, the cash flow, results of operations and financial condition of the Corporation, the need for funds to finance ongoing operations and other considerations as the board of directors of the Corporation considers relevant.

Aboriginal Claims

Aboriginal peoples have claimed aboriginal title and rights to portions of western Canada. The Corporation is not aware that any claims have been made in respect of its properties and assets; however, if a claim arose and was successful such claim may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Seasonality

The level of activity in the Canadian oil and natural gas industry is influenced by seasonal weather patterns. Wet weather and spring thaw may make the ground unstable. Consequently, municipalities and provincial transportation departments enforce road bans that restrict the movement of rigs and other heavy equipment, thereby reducing activity levels. Also, certain oil and natural gas producing areas are located in areas that are inaccessible other than during the winter months because the ground surrounding the sites in these areas consists of swampy terrain. Seasonal factors and unexpected weather patterns may lead to declines in exploration and production activity and corresponding declines in the demand for the goods and services of the Corporation.

Third Party Credit Risk

The Corporation may be exposed to third party credit risk through its contractual arrangements with its current or future joint venture partners, marketers of its petroleum and natural gas production and other parties. In the event such entities fail to meet their contractual obligations to the Corporation, such failures may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. In addition, poor credit conditions in the industry and of joint venture partners may impact a joint venture partner's willingness to participate in the Corporation's ongoing capital program, potentially delaying the program and the results of such program until the Corporation finds a suitable alternative partner.

Conflicts of Interest

Certain directors of the Corporation are also directors of other oil and natural gas companies and as such may, in certain circumstances, have a conflict of interest requiring them to abstain from certain decisions. Conflicts, if any, will be subject to the procedures and remedies of the ABCA. See "Directors and Officers – Conflicts of Interest".

Reliance on Key Personnel

The Corporation's success depends in large measure on certain key personnel. The loss of the services of such key personnel may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. The Corporation does not have any key person insurance in effect for the Corporation. The contributions of the existing management team to the immediate and near term operations of the Corporation are likely to be of central importance. In addition, the competition for qualified personnel in the oil and natural gas industry is intense and 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.

AUDIT COMMITTEE INFORMATION

Audit Committee Charter

The Audit Committee Mandate and Terms of Reference of the Board of Directors of the Corporation is attached hereto as Schedule "C".

Composition of the Audit Committee and Relevant Education and Experience

The Audit Committee of the Corporation is comprised of Raymond Chan (Chair), Michael McGovern and Christopher Fong. The following table sets out the assessment of each Audit Committee member's independence, financial literacy and relevant educational background and experience supporting such financial literacy.

Name	Independent	Financially Literate	Relevant Education and Experience
Raymond Chan	Yes	Yes	Mr. Chan is the Chairman of the Committee. Mr. Chan has been the Executive Chairman of Baytex Energy Corp. (Baytex Energy Trust), a public entity listed on the TSX and New York Stock Exchange, since January 1, 2009. Prior thereto, Mr. Chan was President and Chief Executive Officer of Baytex Energy Ltd. (Baytex Energy Trust), since 2003. Mr. Chan holds a Chartered Accountant designation.
Michael McGovern	Yes	Yes	Mr. McGovern has been executive advisor to Cadent Energy Partners LLC since January 2008.
Christopher L. Fong	Yes	Yes	Mr. Fong has a degree in Chemical Engineering and is a Professional Engineer. Mr. Fong retired from his position as Global Head, Corporate Banking, Energy with RBC Capital Markets after 28 years of service with the bank.

Pre-Approval Policies and Procedures

Under the Audit Committee Mandate and Terms of Reference, the Audit Committee is required to review and pre-approve any non-audit services to be provided to the Corporation or its subsidiaries by the external auditors and consider the impact on the independence of such auditors.

The Audit Committee has determined that in order to ensure the continued independence of the auditors, only limited non audit related services will be provided to the Corporation by PricewaterhouseCoopers LLP and in such case, only with the prior approval of the Audit Committee.

External Auditors Service Fees

The following table sets forth the audit service fees billed by the Corporation's external auditors, PricewaterhouseCoopers LLP, for the periods indicated:

Type of Fees and Fiscal Year Ended	Aggregate Fees Billed
Audit Fees	
Fiscal Year Ended December 31, 2011	$134,000
Fiscal Year Ended December 31, 2010	$108,000
Audit – Related Fees	
Fiscal Year Ended December 31, 2011	$58,000
Fiscal Year Ended December 31, 2010	$87,500
Tax Fees	
Fiscal Year Ended December 31, 2011	$5,500
Fiscal Year Ended December 31, 2010	$4,500
All Other Fees	
Fiscal Year Ended December 31, 2011	$nil
Fiscal Year Ended December 31, 2010	$nil

ADDITIONAL INFORMATION

Additional information relating to the Corporation can be found on SEDAR at www.sedar.com. Additional information, including directors' and officers' remuneration and indebtedness, principal holders of the Corporation's securities and securities authorized for issuance under equity compensation plans is contained in the Corporation's information circular for the Corporation's most recent annual meeting of securityholders that involved the election of directors. Additional financial information is contained in the Corporation's financial statements and the related management's discussion and analysis for the Corporation's most recently completed financial year.

SCHEDULE "A"
FORM 51-101F3
REPORT OF MANAGEMENT AND DIRECTORS ON OIL AND GAS DISCLOSURE

Management of WestFire Energy Inc. ("**WestFire**") are responsible for the preparation and disclosure of information with respect to WestFire's oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data, which are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2011, estimated using forecast prices and costs.

An independent qualified reserves evaluator has evaluated WestFire's reserves data. The report of the independent qualified reserves evaluator is presented below.

The Reserves Committee of the board of directors of WestFire has

(a) reviewed WestFire's procedures for providing information to the independent qualified reserves evaluator;

(b) met with the independent qualified reserves evaluator to determine whether any restrictions affected the ability of the independent qualified reserves evaluator to report without reservation; and

(c) reviewed the reserves data with management and the independent qualified reserves evaluator.

The Reserves Committee of the board of directors has reviewed WestFire's procedures for assembling and reporting other information associated with oil and gas activities and has reviewed that information with management. The board of directors has approved

(a) the content and filing with securities regulatory authorities of the reserves data and other oil and gas information;

(b) the filing of Form 51-102F2 which is the report of the independent qualified reserves evaluator on the reserves data; and

(c) the content and filing of this report.

Because the reserves data are based on judgments regarding future events, actual results will vary and the variations may be material.

DATED as of this 26 day of March, 2012.

(signed) "*Lowell E. Jackson*", President and Chief Executive Officer

(signed) "*Darrin R. Drall*", Vice President, Engineering

(signed) "*Ed Chwyl*", Director

(signed) "*Michael McGovern*", Director

SCHEDULE "B"
FORM 51-101F2
REPORT ON RESERVES DATA
BY INDEPENDENT QUALIFIED RESERVES EVALUATOR

To the board of directors of WestFire Energy Ltd. (the "**Company**"):

1. We have prepared an evaluation of the Company's reserves data as at December 31, 2011. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2011 estimated using forecast prices and costs.

2. The reserves data are the responsibility of the Company's management. Our responsibility is to express an opinion on the reserves data based on our evaluation.

   We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook (the "**COGE Handbook**") prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum (Petroleum Society).

3. Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the reserves data are free of material misstatement. An evaluation also includes assessing whether the reserves data are in accordance with principles and definitions presented in the COGE Handbook.

4. The following table sets forth the estimated future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated by us for the year ended December 31, 2011, and identifies the respective portions thereof that we have evaluated and reported on to the Company's Management:

			Net Present Value of Future Net Revenue (before income taxes, 10% discount rate - $M)			
Independent Qualified Reserves Evaluator	Description and Preparation Date of Evaluation Report	Location of Reserves (County or Foreign Geographic Area)	Audited	Evaluated	Reviewed	Total
GLJ Petroleum Consultants	March 13, 2012	Canada	-	551,530	-	551,530

5. In our opinion, the reserves data respectively evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook, consistently applied. We express no opinion on the reserves data that we reviewed but did not audit or evaluate.

6. We have no responsibility to update our reports referred to in paragraph 4 for events and circumstances occurring after their respective preparation dates.

7. Because the reserves data are based on judgements regarding future events, actual results will vary and the variations may be material.

Executed as to our report referred to above.

GLJ Petroleum Consultants Ltd.,
Calgary, Alberta, Canada,
March 15, 2012

Per: (signed "*Doug R. Sutton, P. Eng.*" Vice President)

SCHEDULE "C"

AUDIT COMMITTEE

MANDATE AND TERMS OF REFERENCE

Role and Objective

The Audit Committee (the "**Committee**") is a committee of the board of directors (the "**Board**") of WestFire Energy Ltd. ("**WestFire**" or the "**Corporation**") to which the Board has delegated its responsibility for the oversight of the following:

1. nature and scope of the annual audit;

2. the oversight of management's reporting on internal accounting standards and practices;

3. the review of financial information, accounting systems and procedures; and

4. financial reporting and financial statements,

and has charged the Committee with the responsibility of recommending, for approval of the Board, the audited financial statements, interim financial statements and other mandatory disclosure releases containing financial information.

The primary objectives of the Committee are as follows:

1. To assist directors of WestFire ("**Directors**") in meeting their responsibilities (especially for accountability) in respect of the preparation and disclosure of the financial statements of the Corporation and related matters;

2. To provide better communication between Directors and external auditors;

3. To enhance the external auditor's independence;

4. To increase the credibility and objectivity of financial reports; and

5. To strengthen the role of the outside Directors by facilitating in depth discussions between Directors on the Committee, management of WestFire ("**Management**") and external auditors.

Membership of Committee

1. The Committee will be comprised of at least three (3) Directors or such greater number as the Board may determine from time to time and all members of the Committee shall be "independent" (as such term is used in Multilateral Instrument 52-110 – Audit Committees ("**MI 52-110**") unless the Board determines that the exemption contained in MI 52 110 is available and determines to rely thereon.

2. The Board may from time to time designate one of the members of the Committee to be the Chair of the Committee.

3. All of the members of the Committee must be "financially literate" (as defined in MI 52 110) unless the Board determines that an exemption under MI 52 110 from such requirement in respect of any particular member is available and determines to rely thereon in accordance with the provisions of MI 52 110.

Mandate and Responsibilities of Committee

It is the responsibility of the Committee to:

1. Oversee the work of the external auditors, including the resolution of any disagreements between Management and the external auditors regarding financial reporting.

2. Satisfy itself on behalf of the Board with respect to WestFire's internal control systems identifying, monitoring and mitigating business risks; and ensuring compliance with legal, ethical and regulatory requirements.

3. Review the annual and interim financial statements of the Corporation and related management's discussion and analysis ("**MD&A**") prior to their submission to the Board for approval. The process should include but not be limited to:

    - reviewing changes in accounting principles and policies, or in their application, which may have a material impact on the current or future years' financial statements;
    - reviewing significant accruals, reserves or other estimates such as the ceiling test calculation;
    - reviewing accounting treatment of unusual or non-recurring transactions;
    - ascertaining compliance with covenants under loan agreements;
    - reviewing disclosure requirements for commitments and contingencies;
    - reviewing adjustments raised by the external auditors, whether or not included in the financial statements;
    - reviewing unresolved differences between Management and the external auditors; and
    - obtain explanations of significant variances with comparative reporting periods.

4. Review the financial statements, prospectuses, MD&A, annual information forms ("**AIF**") and all public disclosure containing audited or unaudited financial information (including, without limitation, annual and interim press releases and any other press releases disclosing earnings or financial results) before release and prior to Board approval. The Committee must be satisfied that adequate procedures are in place for the review of WestFire's disclosure of all other financial information and will periodically assess the accuracy of those procedures.

5. With respect to the appointment of external auditors by the Board:

    - recommend to the Board the external auditors to be nominated;
    - recommend to the Board the terms of engagement of the external auditor, including the compensation of the auditors and a confirmation that the external auditors will report directly to the Committee;
    - on an annual basis, review and discuss with the external auditors all significant relationships such auditors have with the Corporation to determine the auditors' independence;
    - when there is to be a change in auditors, review the issues related to the change and the information to be included in the required notice to securities regulators of such change; and

- review and pre approve any non-audit services to be provided to WestFire or its subsidiaries by the external auditors and consider the impact on the independence of such auditors. The Committee may delegate to one or more independent members the authority to pre-approve non-audit services, provided that the member(s) report to the Committee at the next scheduled meeting such pre–approval and the member(s) comply with such other procedures as may be established by the Committee from time to time.

6. Review with external auditors (and internal auditor if one is appointed by WestFire) their assessment of the internal controls of WestFire, their written reports containing recommendations for improvement, and Management's response and follow-up to any identified weaknesses. The Committee will also review annually with the external auditors their plan for their audit and, upon completion of the audit, their reports upon the financial statements of WestFire and its subsidiaries.

7. Review risk management policies and procedures of the Corporation (i.e., hedging, litigation and insurance).

8. Establish a procedure for:

   - the receipt, retention and treatment of complaints received by WestFire regarding accounting, internal accounting controls or auditing matters; and

   - the confidential, anonymous submission by employees of WestFire of concerns regarding questionable accounting or auditing matters.

9. Review and approve WestFire's hiring policies regarding partners and employees and former partners and employees of the present and former external auditors of the Corporation.

The Committee has authority to communicate directly with the internal auditors (if any) and the external auditors of the Corporation. The Committee will also have the authority to investigate any financial activity of WestFire. All employees of WestFire are to cooperate as requested by the Committee.

The Committee may also retain persons having special expertise and/or obtain independent professional advice to assist in filling their responsibilities at such compensation as established by the Committee and at the expense of WestFire without any further approval of the Board.

Meetings and Administrative Matters

10. At all meetings of the Committee every resolution shall be decided by a majority of the votes cast. In case of an equality of votes, the Chairman of the meeting shall be entitled to a second or casting vote.

11. The Chair will preside at all meetings of the Committee, unless the Chair is not present, in which case the members of the Committee that are present will designate from among such members the Chair for purposes of the meeting.

12. A quorum for meetings of the Committee will be a majority of its members, and the rules for calling, holding, conducting and adjourning meetings of the Committee will be the same as those governing the Board unless otherwise determined by the Committee or the Board.

13. Meetings of the Committee should be scheduled to take place at least four times per year. Minutes of all meetings of the Committee will be taken. The Chief Financial Officer of WestFire will attend meetings of the Committee, unless otherwise excused from all or part of any such meeting by the Chairman.

14. The Committee will meet with the external auditor at least once per year (in connection with the preparation of the year-end financial statements) and at such other times as the external auditor and the Committee consider appropriate.

15. Agendas, approved by the Chair, will be circulated to Committee members along with background information on a timely basis prior to the Committee meetings.

16. The Committee may invite such officers, directors and employees of the Corporation and its subsidiaries as it sees fit from time to time to attend at meetings of the Committee and assist in the discussion and consideration of the matters being considered by the Committee.

17. Minutes of the Committee will be recorded and maintained and circulated to Directors who are not members of the Committee or otherwise made available at a subsequent meeting of the Board.

18. The Committee may retain persons having special expertise and may obtain independent professional advice to assist in fulfilling its responsibilities at the expense of the Corporation as determined by the Committee.

19. Any members of the Committee may be removed or replaced at any time by the Board and will cease to be a member of the Committee as soon as such member ceases to be a Director. The Board may fill vacancies on the Committee by appointment from among its members. If and whenever a vacancy exists on the Committee, the remaining members may exercise all its powers so long as a quorum remains. Subject to the foregoing, following appointment as a member of the Committee each member will hold such office until the Committee is reconstituted.

20. Any issues arising from these meetings that bear on the relationship between the Board and Management should be communicated to the Chairman of the Board by the Committee Chair.