



# INSIGNIA

**INSIGNIA ENERGY LTD.**

**ANNUAL INFORMATION FORM**

**FOR THE YEAR ENDED**

**DECEMBER 31, 2010**

**March 16, 2011**

## TABLE OF CONTENTS

	<b>Page</b>
ABBREVIATIONS .....	3
CONVERSIONS .....	3
CONVENTIONS .....	4
FORWARD-LOOKING STATEMENTS .....	4
CORPORATE STRUCTURE .....	4
GENERAL DEVELOPMENT OF THE BUSINESS .....	5
DESCRIPTION OF THE BUSINESS .....	5
STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION .....	7
DIVIDENDS .....	18
DESCRIPTION OF CAPITAL STRUCTURE .....	19
MARKET FOR SECURITIES .....	20
ESCROWED SECURITIES AND SECURITIES SUBJECT TO CONTRACTUAL RESTRICTION ON TRANSFER .....	20
DIRECTORS AND OFFICERS .....	20
LEGAL PROCEEDINGS AND REGULATORY ACTIONS .....	22
INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS .....	23
TRANSFER AGENTS AND REGISTRARS .....	23
MATERIAL CONTRACTS .....	23
INTERESTS OF EXPERTS .....	24
INDUSTRY CONDITIONS .....	24
RISK FACTORS .....	24
AUDIT COMMITTEE INFORMATION .....	43
ADDITIONAL INFORMATION .....	45

### SCHEDULES

SCHEDULE "A"	– REPORT OF MANAGEMENT AND DIRECTORS ON OIL AND GAS DISCLOSURE
SCHEDULE "B"	– REPORT ON RESERVES DATA BY INDEPENDENT QUALIFIED RESERVES EVALUATORS
SCHEDULE "C"	– AUDIT COMMITTEE MANDATE AND TERMS OF REFERENCE

## ABBREVIATIONS

### Oil and Natural Gas Liquids

Bbl	barrel
Bbls	barrels
Mbbls	thousand barrels
MMbbls	million barrels
Bbls/d	barrels per day
BOPD	barrels of oil per day
NGLs	natural gas liquids
STB	standard tank barrels

### Natural Gas

Mcf	thousand cubic feet
MMcf	million cubic feet
Mcf/d	thousand cubic feet per day
MMcf/d	million cubic feet per day
Mmbtu	million British Thermal Units
Bcf	billion cubic feet
GJ	gigajoule

### Other

AECO	The natural gas storage facility located at Suffield, Alberta.
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). <b>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.</b>
BOE/d	barrel of oil equivalent per day
m <sup>3</sup>	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

## 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 (Alberta)	Hectares	0.400
Hectares (Alberta)	Acres	2.500
Acres (British Columbia)	Hectares	0.405
Hectares (British Columbia)	Acres	2.471

## CONVENTIONS

A reference in this Annual Information Form to "**Insignia**", the "**Company**" or the "**Corporation**" means Insignia 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, 2010. 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, 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 Insignia'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 Insignia'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](http://www.sedar.com)) and at Insignia's website ([www.insigniaenergy.ca](http://www.insigniaenergy.ca)). **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

Insignia Energy Ltd.

Head Office:  
2300, 500 – 4th Avenue S.W.  
Calgary, Alberta T2P 2V6

Registered Office:  
1400, 350 – 7th Avenue S.W.  
Calgary, Alberta T2P 3N9

Insignia was amalgamated under the *Business Corporations Act* (Alberta) (the "**ABCA**") on July 24, 2009.

### **Intercorporate Relationships**

Insignia has no subsidiaries.

## **GENERAL DEVELOPMENT OF THE BUSINESS**

### **Three Year History**

The general development of Insignia'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.

#### ***2009 Grey Wolf Exploration Inc. Acquisition***

On July 23, 2009, the Corporation acquired all of the outstanding common shares of Grey Wolf Exploration Inc. ("**Grey Wolf**"), a publicly listed oil and gas company, pursuant to a plan of arrangement under the ABCA involving Insignia, Grey Wolf and the shareholders of Grey Wolf (the "**2009 Arrangement**"). The total consideration paid by the Corporation under the 2009 Arrangement was payable by the issuance of 14,397,195 Common Shares of Insignia (subject to rounding for fractional shares). In connection with the 2009 Arrangement, the Corporation exercised in full its \$25 million equity line whereby Brookfield Special Services II Limited ("**BSS**"), formerly Tricap Partners Ltd., agreed to subscribe for an additional 3,676,470 Common Shares of Insignia at a price of \$6.80 per share. Subsequent to the completion of the 2009 Arrangement, on July 24, 2009, Insignia and Grey Wolf amalgamated to form "Insignia Energy Ltd."

#### ***2008 Plan of Arrangement***

On July 31, 2008, the Corporation acquired substantially all of the assets and liabilities of Insignia Energy Inc. ("**Insignia Inc.**"), a private oil and gas company, pursuant to a plan of arrangement under the ABCA involving Insignia Inc., the Corporation, BSS, the shareholders of Insignia Inc. and the shareholders of the Corporation (the "**2008 Arrangement**"). The total consideration paid by the Corporation under the 2008 Arrangement was payable by the issuance of 4,112,040 Common Shares of Insignia. The 2008 Arrangement also provided for a recapitalization of the Company whereby BSS (i) converted its outstanding debt of \$27 million in exchange for the issuance of 3,970,589 Common Shares, (ii) acquired 2,205,882 additional Common Shares for gross proceeds to the Company of \$15 million, and (iii) committed to provide the Company with a \$25 million equity line whereby BSS has agreed to subscribe for, prior to July 31, 2009, an additional 3,676,470 Common Shares of Insignia at a price of \$6.80 per share.

### **Significant Acquisitions**

Insignia 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.

## **DESCRIPTION OF THE BUSINESS**

### **General**

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

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

Insignia's principal area of focus is the acquisition of petroleum and natural gas rights in low risk, multi-zone targets in Western Canada and the development of those rights through drilling. Insignia's business and exploration strategy

is to target overlooked play concepts in the developed regions of the corridor. By acquiring assets in this area, Insignia intends to build a production base that can be operated independent of third party influence and with low operating costs.

In developing projects, Insignia intends to spread risk and build alliances with third parties by seeking joint venture partners, where appropriate. The partners approached are expected to be of a 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, Insignia's management team has a demonstrated track record of bringing together all of the key components to a successful exploration and exploration 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 Insignia 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, commodity prices, foreign exchange rates and interest rates.

The oil and natural gas industry is intensely competitive and Insignia 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.

Insignia 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 Insignia 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, 2010, Insignia had 16 full time employees and 3 consultants, all of whom were located at its office in Calgary.

## Reorganizations

Other than the 2008 Arrangement, Insignia 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 – 2008 Plan of Arrangement*".

## 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 Corporation 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 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 February 2, 2011. The effective date of the Statement is December 31, 2010 and the preparation date of the Statement is January 26, 2011.

### 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, 2010 contained in GLJ's report dated February 2, 2011 evaluating the crude oil, natural gas liquids and natural gas reserves of the Corporation as at December 31, 2010 (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, 2010  
FORECAST PRICES AND COSTS**

RESERVES CATEGORY	LIGHT AND MEDIUM OIL		HEAVY OIL		CONVENTIONAL NATURAL GAS		NATURAL GAS LIQUIDS		TOTAL OIL EQUIVALENT	
	Gross (Mbbbl)	Net (Mbbbl)	Gross (Mbbbl)	Net (Mbbbl)	Gross (MMcf)	Net (MMcf)	Gross (Mbbbl)	Net (Mbbbl)	Gross (Mbbbl)	Net (Mbbbl)
PROVED										
Producing	430	370	35	30	18,410	17,279	326	243	3,859	3,523
Developed Non-Producing	8	7	8	8	697	585	17	12	149	124
Undeveloped	593	526	-	-	8,271	7,592	187	145	2,158	1,937
TOTAL PROVED	1,030	903	43	38	27,377	25,456	530	400	6,167	5,584
PROBABLE	614	509	54	43	43,007	38,083	648	457	8,484	7,357
TOTAL PROVED PLUS PROBABLE	1,644	1,413	97	81	70,384	63,539	1,178	858	14,650	12,942

**NET PRESENT VALUES OF FUTURE NET REVENUE**

RESERVES CATEGORY	BEFORE INCOME TAXES DISCOUNTED AT (%/year)					AFTER INCOME TAXES DISCOUNTED AT (%/year)				
	0% (M\$)	5% (M\$)	10% (M\$)	15% (M\$)	20% (M\$)	0% (M\$)	5% (M\$)	10% (M\$)	15% (M\$)	20% (M\$)
PROVED										
Producing	88,634	71,860	61,037	53,451	47,818	88,634	71,860	61,037	53,451	47,818
Developed Non-Producing	3,214	2,672	2,272	1,969	1,733	3,214	2,672	2,272	1,969	1,733
Undeveloped	40,344	20,595	10,222	4,118	220	40,344	20,595	10,222	4,118	220
TOTAL PROVED	132,192	95,127	73,531	59,538	49,770	132,192	95,127	73,531	59,538	49,770
TOTAL PROBABLE	141,334	79,439	48,057	30,048	18,858	141,234	79,422	48,053	30,047	18,858
TOTAL PROVED PLUS PROBABLE	273,526	174,567	121,588	89,585	68,628	273,427	174,549	121,584	89,584	68,628

**TOTAL FUTURE NET REVENUE  
(UNDISCOUNTED)  
AS OF DECEMBER 31, 2010  
FORECAST PRICES AND COSTS**

<b>RESERVES CATEGORY</b>	<b>REVENUE (M\$)</b>	<b>ROYALTIES (M\$)</b>	<b>OPERATING COSTS (M\$)</b>	<b>DEVELOPMENT COSTS (M\$)</b>	<b>ABANDONMENT AND RECLAMATION COSTS (M\$)</b>	<b>FUTURE NET REVENUE BEFORE INCOME TAXES (M\$)</b>	<b>INCOME TAXES (M\$)</b>	<b>FUTURE NET REVENUE AFTER INCOME TAXES (M\$)</b>
Proved Reserves	320,494	32,366	113,338	39,487	3,111	132,192	-	132,192
Proved Plus Probable Reserves	758,640	86,847	264,883	128,611	4,773	273,526	100	273,427

**NET PRESENT VALUE OF  
FUTURE NET REVENUE  
BY PRODUCTION GROUP <sup>(1)</sup>  
AS OF DECEMBER 31, 2010  
FORECAST PRICES AND COSTS**

<b>RESERVES CATEGORY</b>	<b>PRODUCTION GROUP</b>	<b>FUTURE NET REVENUE BEFORE INCOME TAXES (discounted at 10%/year) (M\$)</b>	<b>UNIT VALUE (\$/Mcf) (\$/Bbl)</b>
Proved Reserves	Light and Medium Crude Oil (including solution gas and other by-products)	18,068	\$17.12/Bbl
	Heavy Oil (including solution gas and other by-products)	1,810	\$42.79/Bbl
	Natural Gas (including by-products)	53,653	\$1.99/Mcf
	Total	73,531	\$13.17/BOE
Proved Plus Probable Reserves	Light and Medium Crude Oil (including solution gas and other by-products)	30,919	\$18.62/Bbl
	Heavy Oil (including solution gas and other by-products)	3,431	\$38.89/Bbl
	Natural Gas (including by-products)	87,238	\$1.30/Mcf
	Total	121,588	\$9.39/BOE

*Notes:*

- (1) Other company revenue and costs not related to a specific production group have been allocated proportionately to the above noted production groups.
- (2) Estimated future abandonment and reclamation 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

**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 at January 1, 2011, as follows:

**SUMMARY OF PRICING AND INFLATION RATE ASSUMPTIONS  
FORECAST PRICES AND COSTS**

Year	OIL		NATURAL GAS				Inflation Rates <sup>(1)</sup> %/Year	Exchange Rate <sup>(2)</sup> (\$US/\$Cdn)
	WTI at Cushing Oklahoma (\$US/Bbl)	Edmonton City Gate (\$Cdn/Bbl)	Natural Gas AECO Average Price (\$Cdn/Mmbtu)	Pentanes Plus Edmonton Par (\$Cdn/Bbl)	Butanes Edmonton Par (\$Cdn/Bbl)			
Forecast								
2011	88.00	86.22	4.16	90.54	67.26	2.0	0.980	
2012	89.00	89.29	4.74	91.96	68.75	2.0	0.980	
2013	90.00	90.92	5.31	92.74	70.01	2.0	0.980	
2014	92.00	92.96	5.77	94.82	71.58	2.0	0.980	
2015	95.17	96.19	6.22	98.12	74.07	2.0	0.980	
2016	97.55	98.62	6.53	100.59	75.94	2.0	0.980	
2017	100.26	101.39	6.76	103.42	78.07	2.0	0.980	
2018	102.74	103.92	6.90	106.00	80.02	2.0	0.980	
2019	105.45	106.68	7.06	108.82	82.15	2.0	0.980	
2020	107.56	108.84	7.21	111.01	83.80	2.0	0.980	
2021+			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, 2010, were \$73.06/Bbl for crude oil, \$4.26/Mcf for natural gas and \$58.99/Bbl for natural gas liquids.

**Reconciliation of Changes in Reserves**

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

FACTORS	LIGHT AND MEDIUM OIL			HEAVY OIL			CONVENTIONAL NATURAL GAS		
	Proved (Mbbbl)	Probable (Mbbbl)	Proved Plus Probable (Mbbbl)	Proved (Mbbbl)	Probable (Mbbbl)	Proved Plus Probable (Mbbbl)	Proved (MMcf)	Probable (MMcf)	Proved Plus Probable (MMcf)
<b>December 31, 2009</b>	<b>331</b>	<b>199</b>	<b>530</b>	<b>26</b>	<b>9</b>	<b>35</b>	<b>27,676</b>	<b>42,074</b>	<b>69,749</b>
Discoveries	-	-	-	-	-	-	-	-	-
Extensions	765	462	1,227	21	37	59	2,117	1,266	3,382
Infill Drilling	-	-	-	-	-	-	3,150	3,600	6,750
Improved Recovery	-	-	-	-	-	-	-	-	-
Technical Revisions	68	(46)	23	29	8	37	(361)	(3,472)	(3,833)
Acquisitions	-	-	-	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-	(62)	(12)	(74)
Economic Factors	(1)	(2)	(3)	-	-	-	(521)	(448)	(969)
Production	(133)	-	(133)	(33)	-	(33)	(4,621)	-	(4,621)
<b>December 31, 2010</b>	<b>1,030</b>	<b>614</b>	<b>1,644</b>	<b>43</b>	<b>54</b>	<b>97</b>	<b>27,377</b>	<b>43,007</b>	<b>70,384</b>

FACTORS	NATURAL GAS LIQUIDS			BOE		
	Proved	Probable	Proved Plus Probable	Proved	Probable	Proved Plus Probable
	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)
<b>December 31, 2009</b>	<b>452</b>	<b>636</b>	<b>1,087</b>	<b>5,421</b>	<b>7,856</b>	<b>13,277</b>
Discoveries	-	-	-	-	-	-
Extensions	52	8	61	1,191	719	1,910
Infill Drilling	109	124	233	634	724	1,358
Improved Recovery	-	-	-	-	-	-
Technical Revisions	(1)	(118)	(119)	36	(735)	(699)
Acquisitions	-	-	-	-	-	-
Dispositions	-	-	-	(10)	(2)	(12)
Economic Factors	(4)	(2)	(6)	(92)	(79)	(171)
Production	(77)	-	(77)	(1,013)	(0)	(1,013)
<b>December 31, 2010</b>	<b>530</b>	<b>648</b>	<b>1,178</b>	<b>6,167</b>	<b>8,483</b>	<b>14,650</b>

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 Insignia's assets for the years ended December 31, 2010, 2009 and 2008 and, in the aggregate, before that time based on forecast prices and costs.

#### Proved Undeveloped Reserves

Year	Light and Medium Oil (Mbbl)		Heavy Oil (Mbbl)		Natural Gas (MMcf)		NGLs (Mbbl)	
	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End
	Prior thereto	-	-	-	-	-	-	-
2008	-	-	-	-	-	-	-	-
2009	-	-	-	-	11,052	11,052	152	152
2010	593	593	-	-	3,439	8,271	127	187

#### Probable Undeveloped Reserves

Year	Light and Medium Oil (Mbbl)		Heavy Oil (Mbbl)		Natural Gas (MMcf)		NGLs (Mbbl)	
	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End
	Prior thereto	-	-	-	-	-	-	-
2008	-	-	74	74	449	1,304	1	1
2009	24	24	-	-	33,035	34,112	500	500
2010	387	410	-	-	7,812	35,588	175	509

In general, once proved and/or probable undeveloped reserves are identified they are included in Insignia'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 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:

<u>Year</u>	<u>Forecast Prices and Costs (M\$)</u>	
	<u>Proved Reserves</u>	<u>Proved Plus Probable Reserves</u>
2011	22,990	27,186
2012	10,914	48,094
2013	4,994	30,946
2014	47	10,176
2015	541	4,475
Thereafter	-	7,729
<b>Total Undiscounted</b>	<b>39,487</b>	<b>128,611</b>

The future development costs are capital expenditures required in the future for Insignia 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 \$3.1 million; and forecast prices and costs – proved plus probable reserves \$4.8 million.

On an ongoing basis, Insignia 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, 2010. Unless otherwise indicated, production stated is gross (or working interest) production to the Corporation and reflects average daily production during the month of December 2010. The reserve amounts are stated, before deduction of royalties, as at December 31, 2010 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, 2010.

#### *Pouce Coupe*

The Pouce Coupe property is located approximately 280 miles northwest of Edmonton, Alberta. Insignia holds an average 76% working interest in 20,640 acres of petroleum and natural gas rights of which 7,456 net acres are developed and 8,156 net acres are undeveloped.

The main target for exploration and development on this property is the Doig/Montney section of the Triassic age formations. Drilling targets are defined through both geologic and seismic mapping. Insignia owns a 136 square mile 3D seismic survey that covers the majority of the lands. The area is generally accessible year round for drilling and operational activities except for spring breakup period (April and May).

At December 31, 2010, Insignia had interests in 32 (21.7 net) producing wells and 6 (4.7 net) non-producing wells on the Pouce Coupe property. Late in 2009, insignia drilled a 100% working interest horizontal Doig well in section 29-77-11W6 (102/13-29-77-11W6) and in 2010 the well was completed and placed on production in February. A second 100% working interest well was drilled in section 20-77-11W6 and placed on production in September. Two 50% working interest wells were drilled, completed and placed on production in December. Additional drilling is planned for 2011.

The wells produce into a company owned gathering system and the production is transported to the Spectra Gordondale East gas plant for processing. Insignia holds firm transportation and processing capacity at this plant. Natural gas liquids are trucked to either the CCS terminal at La Glace or to the Enerplus Valhalla 16-29-76-10W6 facility.

December 2010 working interest production to Insignia from this property was approximately 1,415 BOE/d. The GLJ Report has assigned total proved reserves of 2,623 MBOE and total proved plus probable reserves of 7,711 MBOE to the Pouce Coupe property.

#### *Caroline*

The Caroline property is located approximately 70 miles northwest of Calgary, Alberta. Insignia holds an average 67% working interest in 20,835 acres of land of which 4,065 net acres are developed and 9,799 net acres are undeveloped

The area is characterized by natural gas production at drill depths between 2,500 and 3,200 metres. Insignia has identified several potential target zones including the Cardium, Viking, upper Mannville, lower Mannville and Jurassic formations. The area has year-round access for drilling and operational activities except for spring breakup (April and May). In late 2009, one well (16-13-34-7W5) was drilled and completed as a lower Mannville gas well.

The well was placed on production in January 2010. Two additional wells (sections 12 and 14, Twp 34, Rge 7W5) were drilled, completed and placed on production in June. Additional drilling is planned during 2011.

At December 31, 2010, Insignia had interests in 15 (5.8 net) producing wells and 2 (1.4 net) non-producing wells on the Caroline property.

Natural gas produced from this property is processed on a fee basis through the TAQA Caroline gas plant.

December 2010 working interest production to Insignia from this property was approximately 698 BOE/d. The GLJ Report has assigned reserves of 1,470 MBOE Proved and 2,807 MBOE total Proved plus Probable to the Caroline property.

#### *Pembina*

The Pembina property is located approximately 60 miles southwest of Edmonton, Alberta. Insignia holds an average 73% working interest in 5,760 acres of land of which 714 net acres are developed and 3,472 net acres are undeveloped.

The main target for exploration and development on this property is the Cardium formation. The area is generally accessible year round for drilling and operational activities except for spring breakup period (April and May). In 2010 Insignia participated in drilling 4 (1.92 net) horizontal Cardium oil wells. Two 21% working interest wells and one 50% working interest well were placed on production in October. One 100% working interest well was placed on production in December.

At December 31, 2010, Insignia had interests in 7 (3.7 net) producing wells and 3 (1.0 net) non-producing wells. The wells produce into single well batteries at the wellsites. Crude oil is trucked to a pipeline terminal, either the Anterra Breton terminal or the Pembina Pipeline Buck Creek terminal. Solution gas gathered is delivered into the Minnehik Buck Lake gas processing facility.

December 2010 working interest production to Insignia from this property was approximately 381 BOE/d. The GLJ Report assigned reserves of 840 MBOE Proved and 1,342 MBOE total Proved plus Probable to the Pembina property.

#### *Valhalla*

The Valhalla property is located approximately 280 miles northwest of Edmonton, Alberta. Insignia holds an average 76% working interest in 2,720 acres of land of which 1,000 net acres are developed and 1,080 net acres are undeveloped.

The main target for exploration and development on this property is the Doig/Montney section of the Triassic age formations. The area is generally accessible year round for drilling and operational activities except for spring breakup period (April and May).

At December 31, 2010, Insignia had interests in 8 (6.3 net) producing wells and 2 (2.0 net) non-producing wells. The wells produce into a company owned gathering system and the production is transported to the Spectra Gordondale East gas plant for processing. Insignia holds firm transportation and processing capacity at this plant. Natural gas liquids are trucked to either the CCS terminal at La Glace or to the Enerplus Valhalla 16-29-76-10W6 facility.

December 2010 working interest production to Insignia from this property was approximately 64 BOE/d. The GLJ Report assigned reserves of 364 MBOE Proved and 1,066 MBOE total Proved plus Probable to the Valhalla property.

These four properties comprise over 85% of Insignia's Proved and Proved plus Probable reserves in the GLJ Report.

### *Other Properties*

The remaining properties owned by Insignia are located in various areas throughout Alberta, British Columbia and west central Saskatchewan.

December 2010 net production to Insignia from these properties was approximately 1,060 BOE/d. The GLJ Report assigns reserves of approximately 1,072 MBOE Proved and approximately 1,977 MBOE total Proved plus Probable to these properties.

### *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, 2010.

	Oil Wells				Natural Gas Wells			
	Producing		Non-Producing		Producing		Non-Producing	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Alberta	37	16.9	22	15.2	89	55.7	76	51.5
Saskatchewan	2	0.8	9	8.3	15	14.5	13	13.0
B.C.	0	0.0	0	0.0	8	1.3	3	0.5
Total	39	17.7	31	23.5	112	71.5	92	65.0

### *Properties With No Attributed Reserves*

The following table sets out the Corporation's unproved properties as at December 31, 2010.

	Undeveloped Acres	
	Gross	Net
Alberta	154,310	128,497
British Columbia	21,671	7,454
Saskatchewan	58,884	52,439
Total	228,865	188,389

The Corporation expects that rights to explore, develop and exploit 84,000 net acres of its undeveloped land holdings will expire by December 31, 2011; a portion may be continued. Insignia 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*

Insignia is not bound by any agreement (including any transportation agreement), directly or through an aggregator, under which it may be precluded from fully realizing, or may be protected from the full effect of, future market prices for oil or natural gas. In addition, Insignia's transportation obligations or commitments for future physical deliveries of oil or natural gas do not exceed Insignia's expected related future production from its proved reserves, estimated using forecast prices and costs, as disclosed herein.

### *Additional Information Concerning Abandonment and Reclamation Costs*

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

- (a) Insignia 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 Insignia will incur this cost is 274 gross (177.7 net) wells.
- (c) The expected cost to be incurred, net of salvage value is \$26.8 million without discount and \$9.7 million using a discount rate of 10%.
- (d) Of the abandonment and reclamation costs disclosed in paragraph (c) above, \$4.8 million undiscounted and \$1.6 million discounted at 10% were deducted by GLJ as abandonment and reclamation costs.
- (e) \$0.3 million of the \$26.8 million of undiscounted abandonment and reclamation costs disclosed in paragraph (c) above are expected to be paid in the next three financial years by Insignia.

### ***Tax Horizon***

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

### ***Costs Incurred***

The following table summarizes capital expenditures (including costs that were capitalized or charged to expense when incurred) incurred by Insignia with respect to the Insignia assets for the year ended December 31, 2010.

<b>(\$000s)</b>	<b>Capital Expenditures</b>
Property acquisition costs:	
Proved properties	(291)
Unproved properties	3,902
Development Costs	27,549
Exploration Costs	592
Total	<u>31,752</u>

### ***Exploration and Development Activities***

The following table sets forth the gross and net exploratory and development wells on the Insignia assets in which Insignia participated during the year ended December 31, 2010.

	<b>Development Wells</b>		<b>Exploration Wells</b>		<b>Total Wells</b>	
	<b>Gross</b>	<b>Net</b>	<b>Gross</b>	<b>Net</b>	<b>Gross</b>	<b>Net</b>
Light and Medium Oil	4	1.92	-	-	4	1.92
Heavy Oil	10	0.73	-	-	10	0.73
Natural Gas	5	4.00	-	-	5	4.00
Standing			-	-		
Dry	1	1.00	-	-	1	1.00
Total	<u>20</u>	<u>7.65</u>	<u>-</u>	<u>-</u>	<u>20</u>	<u>7.65</u>

### ***Production Estimates***

The following table sets out the volume of production estimated for the year ended December 31, 2011 in the estimates of Insignia's future net revenue from gross proved and gross probable reserves as estimated in the GLJ Report.

	<b>Light and Medium Oil</b>	<b>Heavy Oil</b>	<b>Natural Gas</b>	<b>Natural Gas Liquid</b>	<b>Total BOE</b>
	<b>Bbls/d</b>	<b>Bbls/d</b>	<b>Mcf/d</b>	<b>(Bbls/d)</b>	<b>BOE/d</b>
PROVED					
Developed Producing	300	60	12,585	219	2,676
Developed Non-Producing	0	9	208	6	50
Undeveloped	133	0	1,817	51	486
TOTAL PROVED	433	70	14,609	275	3,212
PROBABLE	65	28	1,168	20	309
TOTAL PROVED PLUS PROBABLE	498	98	15,777	295	3,521

Two properties, Pouce Coupe and Caroline, each contribute over 20% of the total Company production presented in the previous table. The following tables set out the volume of production estimated from the properties for the year ended December 31, 2011 which is incorporated into the estimates of Insignia's future net revenue from gross proved and gross probable reserves as estimated in the GLJ Report.

<b>Pouce Coupe</b>	<b>Light and Medium Oil</b>	<b>Heavy Oil</b>	<b>Natural Gas</b>	<b>Natural Gas Liquids</b>	<b>Total BOE</b>
	<b>Bbls/d</b>	<b>Bbls/d</b>	<b>Mcf/d</b>	<b>Bbls/d</b>	<b>BOE/d</b>
PROVED					
Developed Producing	11	0	7,777	84	1,391
Developed Non-Producing	0	0	0	0	0
Undeveloped	0	0	0	0	0
TOTAL PROVED	11	0	7,777	84	1,391
PROBABLE	0	0	523	5	93
TOTAL PROVED PLUS PROBABLE	11	0	8,300	89	1,484

<b>Caroline</b>	<b>Light and Medium Oil</b>	<b>Heavy Oil</b>	<b>Natural Gas</b>	<b>Natural Gas Liquids</b>	<b>Total BOE</b>
	<b>Bbls/d</b>	<b>Bbls/d</b>	<b>Mcf/d</b>	<b>Bbls/d</b>	<b>BOE/d</b>
PROVED					
Developed Producing	0	0	2,539	87	511
Developed Non-Producing	0	0	0	0	0
Undeveloped	0	0	1,189	41	239
TOTAL PROVED	0	0	3,727	128	750
PROBABLE	0	0	281	10	56
TOTAL PROVED PLUS PROBABLE	0	0	4,008	138	806

### 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 Insignia assets.

	<b>Quarter Ended</b>			
	<b>2010</b>			
	<b>December 31</b>	<b>September 30</b>	<b>June 30</b>	<b>March 31</b>
<b>Average Daily Production <sup>(1)</sup></b>				
Light and Medium Oil (Bbls/d)	460	313	352	289
Heavy Oil (Bbls/d)	136	120	119	87
Gas (Mcf/d)	14,512	12,264	13,055	13,155
Natural Gas Liquids (Bbls/d)	274	240	224	165
Combined (Boe/d)	3,289	2,717	2,871	2,733
<b>Average Prices Received <sup>(2)</sup></b>				
Light and Medium Oil (\$/Bbl)	80.22	72.78	73.39	76.37
Heavy Oil (\$/Bbl)	57.89	55.95	55.81	62.68
Gas (\$/Mcf)	3.58	3.55	3.93	5.07
Natural Gas Liquids (\$/Bbl)	60.96	54.44	57.16	64.81
Combined (\$/Boe)	34.53	31.70	33.61	38.40
<b>Royalties Paid</b>				
Light and Medium Oil (\$/Bbl)	13.98	22.90	26.24	28.00

	Quarter Ended			
	2010			
	December 31	September 30	June 30	March 31
Heavy Oil (\$/Bbl)	5.80	3.24	2.30	2.42
Gas (\$/Mcf) <sup>(5)</sup>	(0.14)	(0.04)	0.41	0.72
Natural Gas Liquids (\$/Bbl)	3.32	2.85	4.87	7.32
Combined (\$/Boe)	1.85	2.84	5.56	6.93
<b>Production Costs</b> <sup>(3)</sup>				
Light and Medium Oil (\$/Bbl)	12.20	13.55	13.97	13.59
Heavy Oil (\$/Bbl)	12.20	13.55	13.97	13.59
Gas (\$/Mcf)	2.03	2.26	2.33	2.27
Natural Gas Liquids (\$/Bbl)	12.20	13.55	13.97	13.59
Combined (\$/Boe)	12.20	13.55	13.97	13.59
<b>Netback Received</b> <sup>(4)</sup>				
Light and Medium Oil (\$/Bbl)	54.04	36.33	33.18	34.78
Heavy Oil (\$/Bbl)	39.89	39.16	39.54	46.67
Gas (\$/Mcf)	1.69	1.33	1.19	2.08
Natural Gas Liquids (\$/Bbl)	45.44	38.04	38.32	43.90
Combined (\$/Boe)	20.48	15.31	14.08	17.88

*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 realized losses/gains on commodity and foreign exchange contracts from revenues.
- (5) Amounts are net of Gas Cost Allowance received in the quarter.

The following table sets forth the average daily production volumes for the year ended December 31, 2010 for each of the important fields comprising the Insignia assets.

Area	Natural Gas (Mcf/d)	Crude Oil and NGL's (Bbls/d)	Boe (Boe/d)
Pouce Coupe, Alberta	6,204	75	1,110
Caroline, Alberta	3,001	80	580
Pembina, Alberta	137	56	79
Valhalla, Alberta	263	32	76
Other Properties	3,643	452	1,058
Total	13,248	695	2,903

Insignia's production for the year ended December 31, 2010 with respect to the properties comprising the Insignia assets was 76% natural gas and 24% crude oil and NGL's.

For the year ended December 31, 2010, 54% of the gross revenue with respect to the properties comprising the Insignia assets was derived from natural gas production and 46% of the gross revenue was derived from crude oil and NGL's.

Insignia currently plans to market 100% of its natural gas, crude oil and NGL's to a third party based on daily indexed prices and/or the monthly index price.

## DIVIDENDS

Insignia has not declared any cash dividends or distributions on the outstanding Common Shares. The Board of Directors of Insignia will determine the actual timing, payment and amount of dividends, if any, that may be paid by Insignia from time to time based upon, among other things, the cash flow, results of operations and financial

conditions of Insignia, the needs for funds to finance ongoing operations and other business considerations as the board of directors of Insignia 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 and an unlimited number of Special Voting 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.

#### ***Special Voting Shares***

There are currently no Special Voting Shares outstanding. The holders of Special Voting Shares are entitled to receive notice of and to attend and vote at all meetings of shareholders of the Corporation. Each Special Voting Share shall entitle the holder thereof to one vote. Except as otherwise may be required by the ABCA, holders of Special Voting Shares shall vote together with holders of Common Shares on all matters submitted to the holders of Common Shares for approval, and no matter submitted for approval by the holders of Common Shares shall be considered to be so approved unless and until it is approved by the requisite percentage of votes cast by holders of Common Shares and Special Voting Shares voting together as a single class. Holders of Special Voting Shares shall not be entitled to dividends.

In the event of the voluntary or involuntary liquidation, dissolution or winding up of the Corporation, or any other distribution of its assets among its shareholders for the purpose of winding up its affairs, holders of Special Voting Shares shall not be entitled to share in the remaining property of the Corporation. If the Corporation subdivides, redivides or changes the then outstanding Common Shares into a greater number of Common Shares, or reduces, combines or consolidates or changes the then outstanding Common Shares into a lesser number of Common Shares, then, contemporaneously therewith, the Corporation shall change the Special Voting Shares in the same proportion and in the same manner. The Subscriber agrees to tender to the Corporation for cancellation without consideration that number of Special Voting Shares then held by it equal to the number of Common Shares to be issued to it pursuant to the provisions of the BSS Equity Commitment on a particular closing date, such cancellation to be effective on such closing date (whether or not certificates representing such Special Voting Shares have been tendered). As of 4:30 p.m. (Calgary time) on the date which is twelve months following the Effective Date, all Special Voting Shares shall be deemed to have been cancelled without consideration. Immediately upon the cancellation of a Special Voting Share(s) (or as soon as reasonably practicable thereafter), the holder thereof shall forthwith return to the Corporation the share certificate representing such cancelled shares.

#### **Constraints**

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

#### **Ratings**

Insignia has not asked for and received a stability rating, or to the knowledge of Insignia, has received any other kind of rating, including, a provisional rating, from one or more approved rating organizations for securities of Insignia 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 ISN. 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		Trading Volume
	High (\$/share)	Low (\$/share)	
<b>2010</b>			
January	2.51	2.17	912,798
February	2.32	1.93	1,026,193
March	2.42	2.01	825,869
April	2.20	2.00	648,845
May	2.10	1.85	330,115
June	2.18	2.01	209,787
July	2.12	1.89	191,022
August	1.95	1.61	316,119
September	1.70	1.62	488,222
October	1.73	1.60	387,828
November	1.90	1.64	633,786
December	1.91	1.72	749,342

### Prior Sales

Other than options to purchase Common Shares, there is no class of securities of Insignia 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, 2010, 7,616,658 Common Shares of Insignia are subject to a contractual restriction on transfer pursuant to the Investor Rights Agreement (See "*Material Contracts – Investor Rights Agreement*") which represents 25% of the Common Shares for Insignia's most recently completed financial year.

## 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.

<u>Name, Province or State and Country of Residence</u>	<u>Position and Office Held</u>	<u>Principal Occupation During the Five Preceding Years</u>	<u>Director Since</u>
Jeffery E. Errico <sup>(1) (2)</sup> Alberta, Canada	Chairman	Chairman of Insignia and Chairman of Insignia Inc., a private oil and gas company; Prior thereto President and Chief Executive Officer of Petrofund Energy Trust, a public oil and gas trust.	July 31, 2008
Jeffrey D. Newcommon Alberta, Canada	President, Chief Executive Officer and Director	President and Chief Executive Officer of Insignia and President and Chief Executive Officer of Insignia Inc., a private oil and gas company; Prior thereto Executive Vice	July 31, 2008

<u>Name, Province or State and Country of Residence</u>	<u>Position and Office Held</u>	<u>Principal Occupation During the Five Preceding Years</u>	<u>Director Since</u>
		President of Petrofund Energy Trust, a public oil and gas trust.	
David Ambedian <sup>(1)(3)</sup> Alberta, Canada	Director	Partner with 32° Capital, a private energy focused investment management company.	July 31, 2008
Sandra S. Cowan <sup>(1)(2)</sup> Ontario, Canada	Director	Independent Businesswoman; Prior thereto Partner and General Counsel of EdgeStone Capital Partners, an independent private equity firm.	July 31, 2008
Christopher P. Slubicki <sup>(2)(3)</sup> Alberta, Canada	Director	President and Chief Executive Officer of OPTI Canada Inc., a public oil and gas company; Prior thereto Vice Chairman of Scotia Waterous, an oil and gas mergers and acquisitions advisory company.	July 31, 2008
Jim Reid <sup>(2)</sup> Alberta, Canada	Director	Managing Partner of Brookfield Asset Management's Energy Group, a global asset manager focussed on property, power and infrastructure assets.	July 31, 2008
Brian Baker Alberta, Canada	Director	Senior Vice President, of Brookfield Asset Management's Energy Group, a global asset manager focussed on property, power and infrastructure assets.	July 31, 2008
Vincent Tkachyk <sup>(3)</sup> Alberta, Canada	Director	Vice President of Canadian Abraxas Petroleum ULC, a private oil and gas company; Prior thereto President and Chief Operating Officer of Grey Wolf Exploration Inc., a public oil and gas company.	July 24, 2009
Glen Fischer Alberta, Canada	Chief Operating Officer	Chief Operating Officer of Insignia and Chief Operating Officer of Insignia Inc., a private oil and gas company; Prior thereto Senior Vice President Operations of Petrofund Energy Trust, a public oil and gas trust.	N/A
Steven J. Mackay Alberta, Canada	Vice President Exploration	Vice President Exploration of Insignia and Vice President, Exploration of Insignia Inc., a private oil and gas company; Prior thereto President of Selkirk Energy Partnership, a private oil and gas company.	N/A
Danny G. Geremia Alberta, Canada	Vice President Finance and Chief Financial Officer	Vice President Finance and Chief Financial Officer of Insignia; Prior thereto Vice President and Chief Financial Officer of Bellamont Exploration Ltd., a public oil and gas company; Prior thereto vice President and Chief Financial Officer of Mission Oil & Gas Inc., a public oil and gas company.	N/A
C. Steven Cohen Alberta, Canada	Corporate Secretary	Partner, Burnet, Duckworth & Palmer LLP (barristers and solicitors).	N/A
James Kidd Alberta, Canada	Assistant Corporate Secretary	Partner, Burnet, Duckworth & Palmer LLP (barristers and solicitors).	N/A

*Notes:*

- (1) Member of the Audit Committee.
- (2) Member of the Governance and Human Resources Committee.
- (3) Member of the Reserves Audit and EH&S Committee.
- (4) Insignia 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 Insignia, as a group, beneficially owned, or controlled or directed, directly or indirectly, 1,282,500 Common Shares or approximately 4.2% of the issued and outstanding Common.

## **Cease Trade Orders, Bankruptcies, Penalties or Sanctions**

### ***Cease Trade Orders***

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 officer 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***

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.

### ***Penalties or Sanctions***

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 Insignia is or was a party to, or that any of its property is or was the subject of, during Insignia's financial year, nor are any such legal proceedings known to Insignia to be contemplated, that involves a claim for damages, exclusive of interest and costs, exceeding 10% of the current assets of Insignia.

## Regulatory Actions

There are no:

- (a) penalties or sanctions imposed against Insignia by a court relating to securities legislation or by a securities regulatory authority during Insignia's financial year;
- (b) other penalties or sanctions imposed by a court or regulatory body against Insignia that would likely be considered important to a reasonable investor in making an investment decision; and
- (c) settlement agreements Insignia entered into before a court relating to securities legislation or with a securities regulatory authority during Insignia'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 Insignia; (b) person or company that beneficially owns, or controls or directs, directly or indirectly, more than 10% of any class or series of Insignia'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 Insignia other than BSS's involvement in the 2008 Arrangement and as disclosed elsewhere in this Annual Information Form. Jim Reid and Brian Baker, directors of Insignia, are officers of an affiliate of BSS.

## 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.

## 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 the most recently completed financial year which are still in effect, other than the investor rights agreement dated June 2, 2008 among BSS, the Corporation and certain individual shareholders of Insignia Inc. (the "**Investor Rights Agreement**").

### Investor Rights Agreement

In connection with the 2008 Arrangement, Insignia, BSS and certain shareholders of Insignia Inc. entered into the Investor Rights Agreement. The Investor Rights Agreement, among other things, provides BSS with board representation, participation, demand distribution, piggyback distribution and other investor rights and contains certain restrictions on the transfer of shares of Insignia applicable to BSS and the other shareholders party thereto.

Pursuant to the Investor Rights Agreement, BSS and its affiliates shall have the right to have (i) one nominee director of Insignia if it beneficially owns not more than 25% and not less than 10% of the issued and outstanding Common Shares and Special Voting Shares taken together and (ii) two nominee directors of Insignia if it beneficially owns more than 25% of the issued and outstanding Common Shares and Special Voting Shares taken together.

Pursuant to the Investor Rights Agreement, BSS and its affiliates have been granted a pre-emptive right. This right permits BSS and its affiliates, subject to the rules or requirements of any recognized exchange, to participate in future issuances of Common Shares (excluding Common Shares issued upon exercise of certain convertible securities, in connection with business combinations, acquisitions or divestitures or in connection with any share split or dividend) so as to afford BSS and its affiliates the ability to maintain its pro rata interest in Common Shares, which pro-rata interest is calculated after giving effect to all of the Common Shares issued to BSS pursuant to the 2008 Arrangement. These rights terminate on the earlier of (i) the date in which BSS and its affiliates beneficially

own less than 10% of the outstanding Common Shares on a non-diluted basis and Special Voting Shares taken together, (ii) in certain instances, on the date when BSS and its affiliates fail to exercise at least 40% of its preemptive right on two occasions and (iii) the date immediately following the fifth anniversary of the closing of the 2008 Arrangement.

BSS and its affiliates have been granted demand and piggyback distribution rights which, in the case of the demand distribution rights, if exercised by BSS, in certain instances, will require Insignia to file a prospectus to qualify for distribution Common Shares owned by BSS and its affiliates and, in the case of the piggyback distribution rights, if exercised by BSS, in certain instances, will require Insignia to qualify for distribution by way of a prospectus offering undertaken by Insignia certain Common Shares owned by BSS and its affiliates. These rights terminate on the date in which BSS and its affiliates beneficially own less than 20% of the outstanding Common Shares on a non-diluted basis and Special Voting Shares taken together. In connection with the demand and piggyback distribution rights, Insignia and BSS have agreed to the expenses to be borne by each and to indemnify each other in certain instances.

BSS and the other shareholders party to the Investor Rights Agreement have agreed not to sell, transfer or otherwise convey beneficial ownership of any Common Shares or Special Voting Shares, except in certain limited circumstances, until three years from the closing of the 2008 Arrangement without the prior written consent of the board of directors of Insignia, excluding the BSS nominees in the case of a proposed transfer by BSS and its affiliates or the prior written consent of BSS in the case of a proposed transfer by an individual shareholder. The Investor Rights Agreement terminates if BSS and its affiliates beneficially owns less than 10% of the Common Shares on a non-diluted basis.

The Investor Rights Agreement is available on SEDAR at [www.sedar.com](http://www.sedar.com).

## **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 Deloitte & Touche 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.

Deloitte & Touche LLP is independent of the Corporation 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, 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.

## **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, the 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 and the issuance of such a licence requires a public hearing and the approval of the Governor in Council.

### ***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<sup>3</sup>/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 and the issuance of such a licence requires a public hearing and the approval of the Governor in Council.

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.

### **Pipeline Capacity**

As a result of pipeline expansions over the past several years, there is ample pipeline capacity to accommodate current production levels of oil and natural gas in western Canada and pipeline capacity does not generally limit the ability to produce and market such production.

### **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. NAFTA carries forward most of the material energy terms that are contained in the Canada United States Free Trade Agreement. 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 prohibits discriminatory border restrictions and export taxes. NAFTA also 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 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.

On October 25, 2007, the Government of Alberta released a report entitled "The New Royalty Framework" ("**NRF**") containing the Government's proposals for Alberta's new royalty regime which were subsequently implemented by the *Mines and Minerals (New Royalty Framework) Amendment Act, 2008*. The NRF took effect on January 1, 2009. On March 11, 2010, the Government of Alberta announced changes to Alberta's royalty system intended to increase Alberta's competitiveness in the upstream oil and natural gas sectors, which changes included a decrease in the maximum royalty rates for conventional oil and natural gas production effective for the January 2011 production month. Royalty curves incorporating the changes announced on March 11, 2010 were released on May 27, 2010.

With respect to conventional oil, the NRF eliminated the classification system used by the previous royalty structure which classified oil based on the date of discovery of the pool. Under the NRF, 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. Royalty rates for conventional oil under the NRF ranged from 0-50%, an increase from the previous maximum rates of 30-35% depending on the vintage of the oil, and rate caps were set at \$120 per barrel. Effective January 1, 2011, the maximum royalty payable under the NRF was reduced to 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<sup>3</sup> compared to the previous royalty curve.

Royalty rates for natural gas under the NRF are similarly determined using a single sliding rate formula incorporating separate variables to account for production rates and market prices. Royalty rates for natural gas under the NRF ranged from 5-50%, an increase from the previous maximum rates of 5-35%, and rate caps were set

at \$16.59/GJ. Effective January 1, 2011, the maximum royalty payable under the NRF was reduced to 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 NRF. Prior to payout, 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: 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. An oil sands project reaches payout when its cumulative revenue exceeds its cumulative costs. Costs include specified allowed capital and operating costs related to the project plus a specified return allowance. As part of the implementation of the NRF, the Government of Alberta renegotiated existing contracts with certain oil sands producers that were not compatible with the NRF.

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.

In April 2005, the Government of Alberta implemented the Innovative Energy Technologies Program (the "IETP"), which 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 is backed by a \$200 million funding commitment over a five-year period beginning April 1, 2005 and provides royalty adjustments to specific pilot and demonstration projects that utilize new or innovative technologies to increase recovery from existing reserves.

On April 10, 2008, the Government of Alberta introduced two new royalty programs to be implemented along with the NRF and 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 spud subsequent to that date, and including wells drilled into pools drilled prior to 1985, among other changes.

On November 19, 2008, in response to the drop in commodity prices experienced during the second half of 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 5-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 new 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 NRF. Pursuant to the changes made to Alberta's royalty structure announced on March 11, 2010, producers were only able to elect to adopt the transitional royalty rates prior to January 1, 2011 and producers that had already elected to adopt such rates as of that date were permitted to switch to Alberta's conventional royalty structure up until February 15, 2011. On January 1, 2014, all producers operating under the transitional royalty rates will automatically become subject to Alberta's conventional royalty structure. 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. The program introduced a drilling royalty credit for new conventional oil and natural gas wells and a new well royalty incentive program, both applying to conventional oil or natural gas wells drilled between April 1, 2009 and March 31, 2010. The drilling royalty credit provides up to a \$200 per metre royalty credit for new wells and is primarily expected to benefit smaller producers since the maximum credit available will be determined using the company's production level in 2008 and its drilling activity between April 1,

2009 and March 31, 2010, favouring smaller producers with lower activity levels. The new well incentive program initially applied to wells that began producing conventional oil or natural gas between April 1, 2009 and March 31, 2010 and provided for a maximum 5% royalty rate for the first 12 months of production on a maximum of 50,000 barrels of oil or 500 MMcf of natural gas. In June, 2009, the Government of Alberta announced the extension of these two incentive programs for one year to March 31, 2011. On March 11, 2010, the Government of Alberta announced that the incentive program rate of 5% for the first 12 months of production would be made permanent, with the same volume limitations.

In addition to the foregoing, on May 27, 2010, in conjunction with the release of the new royalty curves, the Government of Alberta announced a number of new 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.

In addition to the foregoing, Alberta currently maintains a royalty reduction program for low productivity oil and oil sands wells, a royalty adjustment program for deep marginal gas wells and a royalty exemption for re-entry wells, among others.

### ***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 spud between December 1, 2003 and September 1, 2009;
- *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<sup>3</sup> 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<sup>3</sup> 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<sup>3</sup> during the first 12 production months and average daily production less than 23 m<sup>3</sup> for every metre of marginal well depth;
- *Ultra-Marginal Royalty Reduction Program* providing additional royalty breaks for low productivity shallow natural gas wells with a true vertical depth of less than 2,300 metres, average monthly production under 60,000 m<sup>3</sup> during the first 12 production months and average daily production less than 11.5 m<sup>3</sup> (development wells) or 17 m<sup>3</sup> (exploratory wildcat wells) for every 100 metres of marginal well depth;
- *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<sup>3</sup> 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 both 2009 and 2010, the Government of British Columbia allocated \$120 million in royalty credits for 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. Natural gas wells spudded within the 10-month period from September 1, 2009 to June 30, 2010 and brought on production by December 31, 2010 qualify for a 2% royalty rate for the first 12 months of production, beginning from the first month of production for the well (the "**Royalty Relief Program**"). 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. Wells spud between September 1, 2009 and June 30, 2010 may qualify for both the Royalty Relief Program and the Deep Royalty Credit Program but will only receive the benefits of one program at a time. 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 a royalty 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<sup>3</sup> for third and fourth tier oil and \$50 per m<sup>3</sup> 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 a royalty 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<sup>3</sup> of gas for every m<sup>3</sup> 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* which replaces the existing *Freehold Oil and Gas Production Tax Act* and is intended 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 Act.

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<sup>3</sup> for third and fourth tier gas and \$35 per thousand m<sup>3</sup> 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<sup>3</sup> for deep development vertical oil wells, 4,000 m<sup>3</sup> for non-deep exploratory vertical oil wells and 16,000 m<sup>3</sup> 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<sup>3</sup> 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<sup>3</sup> for non-deep horizontal oil wells and 16,000 m<sup>3</sup> for deep horizontal oil wells (more than 1,700 metres or within certain formations);
- *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; and
- *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.

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.

## 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.

In Alberta, the NRF includes 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. The order in which these agreements will receive the reversion notice will depend on their vintage and location, with the older leases and licenses receiving reversion notices first beginning in January 2011. Leases and licences that were granted prior to January 1, 2009 but continued after that date will not be 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.

## 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, providing the legislative authority for the Government of Alberta to implement the policies contained in the ALUF. Regional plans established pursuant to the ALSA are deemed to be legislative instruments equivalent to regulations and are 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, 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. Although no regional plans have been established under the ALSA, the planning process is underway for the Lower Athabasca Region (which contains the majority of oil sands development) and the South Saskatchewan Region. While the potential impact of the regional plans established under the ALSA cannot yet be determined, it is clear that such regional plans may have a significant impact on land use in Alberta and may affect the oil and gas industry.

## **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 and commits Canada to reduce its GHG emissions levels to 6% below 1990 "business-as-usual" levels by 2012.

On February 14, 2007, the House of Commons passed Bill C-288, *An Act to ensure Canada meets its global climate change obligations under the Kyoto Protocol*. The resulting *Kyoto Protocol Implementation Act* came into force on June 22, 2007. Its stated purpose is to "ensure that Canada takes effective and timely action to meet its obligations under the Kyoto Protocol and help address the problem of global climate change." It requires the federal Minister of the Environment to, among other things, produce an annual climate change plan detailing the measures to be taken to ensure Canada meets its obligations under the Kyoto Protocol. It also authorizes the establishment of regulations respecting matters such as emissions limits, monitoring, trading and enforcement.

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<sub>2</sub> equivalents per facility per year for natural gas pipelines; (ii) 3,000 tonnes of CO<sub>2</sub> 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: 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<sub>2</sub> 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.

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.

Under the Updated Action Plan, regulated entities will also be 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.

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.

The United Nations Framework Convention on Climate Change is working towards establishing a successor to the Kyoto Protocol. From December 7 to 18, 2009, a meeting between government leaders and representatives from approximately 170 countries in Copenhagen, Denmark (the "**Copenhagen Conference**") resulted in 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. From November 29 to December 10, 2010, a meeting between representatives from approximately 190 countries in Cancun, Mexico resulted in the Cancun Agreements, in which developed countries committed to additional measures to help developing countries deal with climate change. Unlike the Kyoto Protocol, however, 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 on January 29, 2010 that it will seek to achieve a 17% reduction in GHG emissions from 2005 levels by 2020. This goal is similar to the goal expressed in previous policy documents which were discussed above.

Although draft regulations for the implementation of the Updated Action Plan were intended to be published in the fall of 2008 and become binding on January 1, 2010, no such regulations 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.

On December 23, 2010, the United States Environmental Protection Agency indicated its intention to impose GHG emissions standards for fossil fuel-fired power plants by July, 2011 and for refineries by December, 2011.

### ***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<sub>2</sub> 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. Unlike the Updated Action Plan, the CCEMA does not contemplate a linkage to external compliance mechanisms such as the Kyoto Protocol's Clean Development Mechanism.

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 initial level of the tax was set at \$10 per tonne of CO<sub>2</sub> equivalent and rose to \$15 per tonne of CO<sub>2</sub> equivalent on July 1, 2009 and \$20 per tonne of CO<sub>2</sub> equivalent on July 1, 2010. It is scheduled to further increase at a rate of \$5 per tonne of CO<sub>2</sub> equivalent on July 1 of every year until it reaches \$30 per tonne of CO<sub>2</sub> 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 will come 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. It is expected that GHG emissions restrictions will be applied to facilities emitting more than 25,000 tonnes of CO<sub>2</sub> equivalents per year, which will be required to meet established targets through a combination of emissions allowances issued by the Government of British Columbia and the purchase of emissions offsets generated through activities that result in a reduction in 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<sub>2</sub> equivalents per year to begin reporting their emissions. Facilities reporting emissions greater than 25,000 tonnes of CO<sub>2</sub> equivalents per year are required to have their emissions reports verified by a third party.

## ***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.**

### **Significant Shareholder**

BSS is a significant shareholder of Insignia owning, as of the date hereof, approximately 16,565,752 voting shares or 54% of the outstanding voting shares. As such, BSS will have, subject to applicable law, the ability to determine the outcome of certain matters submitted to shareholders for approval in the future, including the election and removal of directors, amendments to the Insignia's corporate governing documents and certain business combinations. Insignia's interests and those of its controlling shareholder may at times conflict, and this conflict might be resolved against Insignia's interests. The concentration of control in the hands of a significant shareholder may impact the potential for the initiation, or the success, of an unsolicited bid for Insignia's securities.

### **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. 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, operating and other costs. Completion of a well does not assure a profit on the investment or recovery of drilling, completion and operating costs. In addition, drilling hazards or environmental damage could greatly increase the cost of operations, and various field operating conditions may adversely affect the production from successful wells. These conditions include delays in obtaining governmental approvals or consents, shut-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 hazards such as fire, explosion, blowouts, cratering, sour gas releases and spills, each of which could result in substantial damage to oil and natural gas wells, production facilities, other property and the environment or 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. In accordance with industry practice, the Corporation is not fully insured against all of these risks, nor are all such risks insurable. Although the Corporation maintains liability insurance in an amount that it considers consistent with industry practice, the nature of these risks is such that liabilities could exceed policy limits, in which event the Corporation could incur significant costs. 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.

### **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 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 gas acquisition, development and exploration activities. Prices for oil and gas are subject to large fluctuations in response to relatively minor changes in the supply of and demand for oil and gas, market uncertainty and a variety of additional factors beyond the control of the Corporation. These factors include economic conditions, in the United States and Canada, the actions of OPEC, governmental regulation, political stability in the Middle East and elsewhere, the foreign supply of oil and 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 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.

Petroleum 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 the ongoing credit and liquidity concerns. Volatile oil and gas prices make it difficult to estimate the value of producing properties for acquisition and often cause disruption in the market for oil and 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.

In addition, bank borrowings available to the Corporation may, in part, be determined by the Corporation's borrowing base. A sustained material decline in prices from historical average prices could reduce the Corporation's borrowing base, therefore reducing the bank credit available to the Corporation which could require that a portion, or all, of the Corporation's bank debt be repaid.

### **Failure to Realize Anticipated Benefits of Acquisitions and Dispositions**

The Corporation makes 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 business 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 are 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 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.

### **Competition**

The petroleum industry is competitive in all its phases. The Corporation competes with numerous other organizations 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 price, 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 natural gas and crude oil and increase the Corporation's costs, any 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 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.

### **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**

Canada is a signatory to the United Nations Framework Convention on Climate Change and has ratified the Kyoto Protocol established thereunder to set legally binding targets to reduce nationwide emissions of carbon dioxide, methane, nitrous oxide and other so-called "greenhouse gases". Recently, representatives from approximately 170 countries met in Copenhagen, Denmark to attempt to negotiate a successor to the Kyoto Protocol. Pursuant to the resulting Copenhagen Accord, a non-binding political consensus rather than a binding international treaty such as the Kyoto Protocol, the Government of Canada revised its emissions reduction targets slightly. There has been much public debate with respect to Canada's ability to meet these targets and the Government's strategy or alternative strategies with respect to climate change and the control of greenhouse gases. The Corporation's exploration and production facilities and other operations and activities emit greenhouse gases and require the Corporation to comply with Alberta's greenhouse gas emissions legislation contained in the *Climate Change and Emissions Management Act* and the *Specified Gas Emitters Regulation*. The Corporation may also be required to comply with the regulatory scheme for greenhouse gas emissions ultimately adopted by the federal government, which is now expected to be modified to ensure consistency 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 gas regulations, whether to meet the limits required by the Kyoto Protocol, 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 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 Common Shares 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. If the Corporation's revenues or reserves decline, it may not have access to the capital necessary to undertake or complete future drilling programs. In addition, uncertain levels of near term industry activity coupled with the present global credit crisis exposes the Corporation to additional access to capital risk. 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. From time to time, the Corporation may require additional financing in order to carry out its oil and gas acquisition, exploration and development activities. 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. If the Corporation's cash flow from operations is not sufficient to satisfy its capital expenditure requirements, there can be no assurance that additional debt or equity financing will be available to meet these requirements or, if available, on terms acceptable to the Corporation. Continued uncertainty in domestic and international credit markets could materially affect the Corporation's ability to access sufficient capital for its capital expenditures and acquisitions, and as a result, may have a material adverse effect on the Corporation's ability to execute its business strategy and on its business, financial condition, results of operations and prospects.

### **Issuance of Debt**

From time to time the Corporation may enter into transactions to acquire assets or the 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 equity and/or 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, if commodity prices increase beyond the levels set in such agreements, the Corporation will not benefit from such increases and the Corporation may nevertheless be obligated to pay royalties on such higher prices, even though not received by it, after giving effect to such agreements. 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.

### **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 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 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, such 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, 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 will 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 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 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 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 Dave Ambedian (Chair), Sandra Cowan and Jeffery E. Errico. 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.

<u>Name</u>	<u>Independent</u>	<u>Financially Literate</u>	<u>Relevant Education and Experience</u>
David Ambedian	Yes	Yes	Mr. Ambedian is a Partner with 32° Capital Inc., a private energy focused investment management company. He is also currently a director of Caltex Energy Inc. and Evolve Exploration Ltd., both of which are private oil and gas companies. Prior to September 2004, Mr. Ambedian was a director of Bear Ridge Resources Ltd., a public oil and gas company listed on the TSX, a director, Vice-President, Finance & Chief Financial Officer of Hygait Resources Ltd., a director, co-founder, Vice-President, Finance and Chief Financial Officer of Glacier Energy Limited, a co-founder and Vice-President, Finance & Chief Financial Officer of Ice Energy Limited and a cofounder and Vice-President, Finance & Chief Financial Officer of Avalanche Energy Limited, all of which are private oil and gas companies. Mr. Ambedian holds a Bachelor of Commerce degree from the University of Alberta and is a Certified Management Accountant.
Sandra S. Cowan	Yes	Yes	Ms. Cowan is an Independent Businesswoman. Prior thereto she was Partner and General Counsel of EdgeStone Capital Partners, an independent private equity firm managing over \$1 billion of private capital. Prior to joining EdgeStone in 2001, Ms. Cowan practiced law for over 15 years, most recently as a senior partner of Goodman and Carr LLP. Her practice specialized in private equity and corporate finance transactions, including fund formation, mergers, acquisitions and divestitures, cross-border and public market transactions. Ms. Cowan has a Bachelor of Laws from the University of Western Ontario and serves on a number of private and public boards.
Jeffery E. Errico	Yes	Yes	Mr. Errico is a Professional Engineer with a Bachelor of Applied Science Degree in Chemical Engineering from the University of British Columbia. He currently serves as a director of Crew Energy Inc. and Inter Pipeline Fund; both of which trade on the TSX. He is also a director of NCE Diversified Management (10) Corp. and NCE Diversified Management (11) Corp. He was most recently with Petrofund Energy Trust from 1995 to 2006 in various senior management positions including CEO from 2003 to 2006.

### 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 Deloitte & Touche 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 paid by the Corporation to its external auditors, Deloitte & Touche LLP, for the periods indicated:

<u>Type of Fees and Fiscal Year Ended</u>	<u>Aggregate Fees Billed</u>	<u>Description of Services</u>
Audit Fees		
Fiscal Year Ended December 31, 2010	\$58,000	2009 Audit Fees
Fiscal Year Ended December 31, 2009	\$75,000	2008/2009 Audit Fees
Audit – Related Fees		
Fiscal Year Ended December 31, 2010	\$47,000	Review of quarterly financial statements
Fiscal Year Ended December 31, 2009	\$48,000	Review of quarterly financial statements
Tax Fees		
Fiscal Year Ended December 31, 2010	\$1,000	
Fiscal Year Ended December 31, 2009	\$14,000	
All Other Fees		
Fiscal Year Ended December 31, 2010	-	
Fiscal Year Ended December 31, 2009	\$26,000	Securities Filings/IFRS

#### **ADDITIONAL INFORMATION**

Additional information relating to the Corporation can be found on SEDAR at [www.sedar.com](http://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 Insignia Energy Ltd. (the "**Corporation**") is responsible for the preparation and disclosure of information with respect to the Corporation'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, 2010 estimated using forecast prices and costs.

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

The Reserves Audit and EH&S Committee of the board of directors of the Company has

- (a) reviewed the Company'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 Audit and EH&S Committee of the board of directors has reviewed the Company'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

- (d) the content and filing with securities regulatory authorities of the reserves data and other oil and gas information;
- (e) the filing of the report of the independent qualified reserves evaluator on the reserves data; and
- (f) 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 2<sup>nd</sup> day of February, 2011.

(signed) "*Jeffrey D. Newcommon*"  
 Jeffrey D. Newcommon  
 President and Chief Executive Officer

(signed) "*Glen C. Fischer*"  
 Glen C. Fischer  
 Chief Operating Officer

(signed) "*Vincent Tkachyk*"  
 Vincent Tkachyk  
 Director

(signed) "*Christopher Slubicki*"  
 Christopher Slubicki  
 Director

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

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

1. We have prepared an evaluation of the Company's reserves data as at December 31, 2010. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2010 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, 2010, and identifies the respective portions thereof that we have evaluated and reported on to the Company's Board of Directors:

Independent Qualified Reserves Evaluator	Description and Preparation Date of Evaluation Report	Location of Reserves (County or Foreign Geographic Area)	Net Present Value of Future Net Revenue (before income taxes, 10% discount rate - \$M)			
			Audited	Evaluated	Reviewed	Total
GLJ Petroleum Consultants Ltd.	January 26, 2011	Canada	-	121,588	-	121,588

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,  
 February 2, 2011

Per: (signed "Bryan M. Joa, 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 Insignia Energy Ltd. ("**Insignia**" or the "**Corporation**") to which the Board has delegated its responsibility for the oversight of the nature and scope of the annual audit, the oversight of management's reporting on internal accounting standards and practices, the review of financial information, accounting systems and procedures, 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 in meeting their responsibilities (especially for accountability) in respect of the preparation and disclosure of the financial statements of Insignia 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 and external auditors.

**Membership of Committee**

6. The Committee will comprise at least three (3) directors of Insignia 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 or unless the Board determines that MI 52-110 does not currently apply to the Corporation.
7. The Board of Directors may from time to time designate one of the members of the Committee to be the Chair of the Committee.
8. 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:

9. Oversee the work of the external auditors, including the resolution of any disagreements between management and the external auditors regarding financial reporting.
10. Satisfy itself on behalf of the Board with respect to Insignia's internal control systems.

11. Review the annual and interim financial statements of Insignia 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.
12. 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 Insignia's disclosure of all other financial information and will periodically assess the accuracy of those procedures.
13. 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 Insignia 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.
14. Review with external auditors (and internal auditor if one is appointed by Insignia) their assessment of the internal controls of Insignia, 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 Insignia and its subsidiaries.

15. Review risk management policies and procedures of Insignia (i.e. hedging, litigation and insurance).
16. Establish a procedure for:
  - the receipt, retention and treatment of complaints received by Insignia regarding accounting, internal accounting controls or auditing matters; and
  - the confidential, anonymous submission by employees of Insignia of concerns regarding questionable accounting or auditing matters.
17. Review and approve Insignia's hiring policies regarding partners and employees and former partners and employees of the present and former external auditors of Insignia.

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 Insignia. All employees of Insignia 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 Insignia without any further approval of the Board.

#### **Meetings and Administrative Matters**

- 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 chairperson of the meeting shall be entitled to a second or casting vote.
- 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.
- 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.
- 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 (or prior to appointment the person carrying out the duties of the Chief Financial Officer) will attend meetings of the Committee, unless otherwise excused from all or part of any such meeting by the Chair.
- 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.
- Agendas, approved by the Chair, will be circulated to Committee members along with background information on a timely basis prior to the Committee meetings.
- The Committee may invite such officers, directors and employees of the Corporation 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.
- 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.

- 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.
- 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.
- 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.