



**2007 ANNUAL INFORMATION FORM**

**March 18, 2008**

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## GLOSSARY OF TERMS

Capitalized terms in this Annual Information Form have the meanings set forth below:

### *Entities*

**Board of Directors** means the board of directors of Bonavista Petroleum.

**Bonavista, we, us, our** or **Trust** means Bonavista Energy Trust and all its controlled entities on a consolidated basis.

**BOGL** means Bonavista Oil & Gas Ltd.

**Bonavista Energy LP** means Bonavista Energy LP, a limited partnership.

**Bonavista ExchangeCo** means Bonavista ExchangeCo Ltd.

**Bonavista Partnership** means Bonavista Petroleum, a general partnership.

**Bonavista Petroleum** means Bonavista Petroleum Ltd.

**Bonavista Trust (2003)** means Bonavista Trust (2003), a trust.

**Trustee** means Valiant Trust Company our trustee.

**Unitholders** means holders of our Trust Units.

### *Independent Engineering*

**GLJ** means GLJ Petroleum Consultants Ltd., independent petroleum consultants of Calgary, Alberta.

**GLJ Report** means the report prepared by GLJ dated March 10, 2008 with a preparation date of February 26, 2008 evaluating the crude oil, natural gas, natural gas liquids and sulphur reserves attributable to certain of our oil and natural gas assets at December 31, 2007.

**Ryder Scott** means Ryder Scott Company, independent petroleum consultants of Calgary, Alberta.

**Ryder Scott Report** means the report prepared by Ryder Scott dated and prepared March 4, 2008 evaluating the crude oil, natural gas, natural gas liquids and sulphur reserves attributable to certain of our oil and natural gas assets at December 31, 2007.

### *Securities*

**7.5% Convertible Debentures** means our 7.5% convertible unsecured subordinated debentures.

**6.75% Convertible Debentures** means our 6.75% convertible unsecured subordinated debentures.

**Exchangeable Shares** means exchangeable shares of Bonavista Petroleum which are exchangeable for Trust Units.

**Exchange Ratio** means the ratio at which Exchangeable Shares may be converted to Trust Units.

**Notes** means the unsecured subordinated promissory notes issued by Bonavista Petroleum now held by us.

**Note Indenture** means the note indenture relating to the issuance of the Notes.

**NPI** means the net profit interest in the petroleum substances owned by the Bonavista Partnership held by us.

**Special Voting Right** means the special voting right issued by us entitling holders of Exchangeable Shares to voting rights at the meeting of Unitholders.

**Trust Indenture** means the amended and restated trust indenture between Valiant Trust Company and Bonavista Petroleum made as of May 22, 2003.

**Trust Unit** means a unit issued by us, each unit representing an equal undivided beneficial interest in our net assets.

## ABBREVIATIONS

### Oil and Natural Gas Liquids

bbbl	Barrel
bbls	Barrels
bbls/d	barrels per day
Mbbls	thousand barrels
MMbbls	million barrels
NGLs	natural gas liquids
Mstb	thousand stock tank barrels of oil
Mboe	thousand barrels of oil equivalent
MMboe	million barrels of oil equivalent
boe/d	barrels of oil equivalent per day

### Natural Gas

Mcf	thousand cubic feet
MMcf	million cubic feet
Bcf	billion cubic feet
Mcf/d	thousand cubic feet per day
MMcf/d	million cubic feet per day
m <sup>3</sup>	cubic metres
MMbtu	million British Thermal Units
GJ	Gigajoule

### Other

BOE or boe	means barrel of oil equivalent
mcfe	means thousand cubic feet of gas equivalent
WTI	means West Texas Intermediate.
°API	means the measure of the density or gravity of liquid petroleum products derived from a specific gravity.
psi	means pounds per square inch.
\$000s	means thousands of dollars.

We have adopted the standard of 6 mcf:1 bbl when converting natural gas to oil and 1 bbl:6 mcf when converting oil to natural gas. **Boe's and Mcfe's may be misleading, particularly if used in isolation. A boe conversion ratio of 6 mcf:1 Boe or an Mcfe conversion of 1 bbl:6 Mcfe is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.**

## CONVERSIONS

The following table sets forth certain conversions between Standard Imperial Units and the International System of Units (or metric units).

<u>To Convert From</u>	<u>To</u>	<u>Multiply By</u>
Mcf	cubic metres	28.174
cubic metres	cubic feet	35.494
bbls	cubic metres	0.159
cubic metres	bbls	6.289
feet	metres	0.305
metres	feet	3.281
miles	kilometres	1.609
kilometres	miles	0.621
acres	hectares	0.405
hectares	acres	2.471
gigajoules	MMbtu	0.950
MMbtu	gigajoules	1.0526

All dollar amounts set forth in this Annual Information Form are in Canadian dollars, except where otherwise indicated.

## NOTICE TO READER

### Special Note Regarding Forward-Looking Statements

Certain statements contained in this Annual Information Form, and in certain documents incorporated by reference into this Annual Information Form, constitute forward-looking statements. These statements relate to future events or our future performance. All statements other than statements of historical fact may be forward-looking statements. Forward-looking statements are often, but not always, identified by the use of words such as "seek", "anticipate", "budget", "plan", "continue", "estimate", "expect", "forecast", "may", "will", "project", "predict", "potential", "targeting", "intend", "could", "might", "should", "believe" and similar expressions. These statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking statements. We believe the expectations reflected in those forward-looking statements are reasonable but no assurance can be given that these expectations will prove to be correct and such forward-looking statements included in, or incorporated by reference into, this Annual Information Form should not be unduly relied upon. These statements speak only as of the date of this Annual Information Form or as of the date specified in the documents incorporated by reference into this Annual Information Form, as the case may be.

In particular, this Annual Information Form, and the documents incorporated by reference, contain forward-looking statements pertaining to the following:

- the performance characteristics of our oil and natural gas properties;
- oil and natural gas production levels;
- the size of the oil and natural gas reserves;
- projections of market prices and costs and the related sensitivities of distributions;
- supply and demand for oil and natural gas;
- expectations regarding the ability to raise capital and to continually add to reserves through acquisitions and development;

- treatment under governmental regulatory regimes and tax laws; and
- capital expenditures programs.

The actual results could differ materially from those anticipated in these forward-looking statements as a result of the risk factors set forth below and elsewhere in this Annual Information Form:

- volatility in market prices for oil and natural gas;
- liabilities inherent in oil and natural gas operations;
- uncertainties associated with estimating oil and natural gas reserves;
- competition for, among other things, capital, acquisitions of reserves, undeveloped lands and skilled personnel;
- incorrect assessments of the value of acquisitions;
- geological, technical, drilling and processing problems;
- changes in income tax laws or changes in tax laws and incentive programs relating to the oil and gas industry and income trusts; and
- the other factors discussed under "*Risk Factors*".

Statements relating to "reserves" or "resources" are deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the resources and reserves described can be profitably produced in the future. Readers are cautioned that the foregoing lists of factors are not exhaustive. The forward-looking statements contained in this Annual Information Form and the documents incorporated by reference herein are expressly qualified by this cautionary statement. We do not undertake any obligation to publicly update or revise any forward-looking statements, except as required by law.

### **Description of Funds from Operations**

This Annual Information Form refers to funds from operations derived from cash provided by operating activities before changes in non-cash operating working capital, asset retirement expenditures and plan of arrangement costs. Funds from operations as presented does not have any standardized meaning prescribed by Canadian generally accepted accounting principles ("**GAAP**"), and therefore it may not be comparable with the calculation of similar measures for other entities. Funds from operations as presented is not intended to represent operating cash flow or operating profits for the period nor should it be viewed as an alternative to cash flow provided by operating activities, net earnings or other measures of financial performance calculated in accordance with Canadian GAAP.

For more information, see our "*Management's Discussion and Analysis*" which includes a definition of "funds from operations" and reconciliation to cash provided by operating activities, which has been filed on SEDAR at [www.sedar.com](http://www.sedar.com).

### **Access to Documents**

Any document referred to in this Annual Information Form and described as being filed on SEDAR at [www.sedar.com](http://www.sedar.com) (including those documents referred to as being incorporated by reference in this Annual Information Form) may be obtained free of charge from us at Suite 700, 311 – 6<sup>th</sup> Avenue S.W., Calgary, Alberta, T2P 3H2.

## BONAVISTA ENERGY TRUST

### General

We are an open-end investment trust created on May 22, 2003 under the laws of the Province of Alberta pursuant to the Trust Indenture. Valiant Trust Company has been appointed as trustee under the Trust Indenture. The beneficiaries of the Trust are holders of the Trust Units. Our principal and head office is located at Suite 700, 311 – 6<sup>th</sup> Avenue S.W., Calgary, Alberta, T2P 3H2.

We commenced operations on July 2, 2003 as a result of the completion of a plan of arrangement under the *Business Corporations Act* (Alberta). Pursuant to this plan of arrangement, holders of common shares of Bonavista Petroleum received either Trust Units or Exchangeable Shares for their common shares. Coincident with the plan of arrangement becoming effective, certain of Bonavista Petroleum's assets were acquired by NuVista Energy Ltd., and the common shares of NuVista Energy Ltd. were distributed to the former holders of common shares of Bonavista Petroleum.

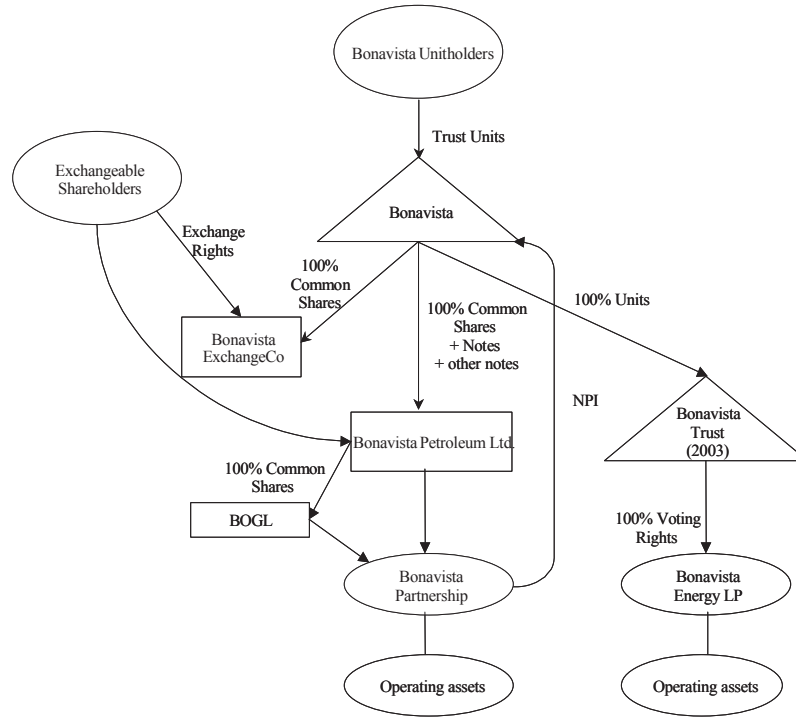
### Inter-Corporate Relationships

The following are the name, the percentage of voting securities that we own and the jurisdiction of incorporation, continuance or formation of our material subsidiaries, partnerships and trusts owned either, direct and indirect, as at the date hereof.

	<b>Percentage of voting securities (directly or indirectly)</b>	<b>Nature of Entity</b>	<b>Jurisdiction of Incorporation/ Formation</b>
Bonavista Petroleum Ltd.	100%	Corporation	Alberta
Bonavista ExchangeCo Ltd.	100%	Corporation	Alberta
Bonavista Oil & Gas Ltd.	100%	Corporation	Alberta
Bonavista Trust (2003)	100%	Trust	Alberta
Bonavista Petroleum	100%	General Partnership	Alberta
Bonavista Energy LP	100%	Limited Partnership	Alberta

## Our Organization Structure

The following diagram describes the inter-corporate relationships among us and our material subsidiaries, trusts and partnerships at December 31, 2007.



### Notes:

- (1) The Unitholders own 100% of our equity.
- (2) Bonavista Petroleum had a total of 12,230,109 Exchangeable Shares issued and outstanding as at December 31, 2007, which were exchangeable for 21,065,629 Trust Units.
- (3) Cash distributions are made on a monthly basis to Unitholders based upon our cash flow. Our primary sources of cash flow are payments from Bonavista Partnership and Bonavista Petroleum pursuant to the NPI and interest on the principal amount of the Notes and other intercorporate notes, and from Bonavista Trust (2003) by way of interest payments and distributions. In addition to such amounts, prepayments in respect of principal on the Notes and other intercorporate notes may be made from time to time by Bonavista Petroleum and Bonavista Trust (2003) before the maturity of such notes.
- (4) Does not include other non material subsidiaries or partnerships.

## **GENERAL DEVELOPMENT OF OUR BUSINESS**

### **History and Development**

On July 2, 2003, Bonavista Petroleum completed a plan of arrangement whereby holders of common shares of Bonavista Petroleum received either Trust Units or Exchangeable Shares for their common shares. Coincident with the plan of arrangement becoming effective, certain of Bonavista Petroleum's assets were acquired by NuVista Energy Ltd., and the common shares of NuVista Energy Ltd. were distributed to the former holders of common shares of Bonavista Petroleum.

Over the last four and one half fiscal years, we have grown our business through a combination of development and exploration of our assets as well as the completion of a number of strategic acquisitions in western Canada.

On January 29, 2004, we closed a public offering of \$100 million aggregate principal amount of 7.5% Convertible Debentures. The 7.5% Convertible Debentures, with a face value of \$1,000 per debenture, have a coupon of 7.5%, mature on June 30, 2009 and are convertible into Trust Units at a price of \$23.00 per Trust Unit. Holders converting their 7.5% Convertible Debentures will receive accrued and unpaid interest thereon. Interest on the 7.5% Convertible Debentures is paid semi-annually. The 7.5% Convertible Debentures are listed for trading on the Toronto Stock Exchange under the symbol "BNP.DB".

On December 13, 2004, Bonavista Petroleum entered into a purchase agreement whereby it agreed to purchase certain oil and natural gas properties and assets in the Rigel, Nig Creek/N. Buick and Jedney/Blueberry areas of Northeast British Columbia for an aggregate cash purchase price of approximately \$414 million, after certain adjustments. This transaction closed on December 31, 2004.

Also on December 31, 2004, we closed a public offering of \$135 million aggregate principal amount of 6.75% Convertible Debentures and 10.9 million subscription receipts, each representing the right to receive one Trust Unit, for aggregate proceeds of approximately \$281.8 million. The 6.75% Convertible Debentures, with a face value of \$1,000 per debenture have a coupon rate of 6.75%, mature on June 30, 2010 and are convertible into Trust Units at a price of \$29.00 per Trust Unit. Holders converting their 6.75% Convertible Debentures will receive accrued and unpaid interest thereon. Interest on the 6.75% Convertible Debentures is paid semi-annually. The 6.75% Convertible Debentures are listed for trading on the Toronto Stock Exchange under the symbol "BNP.DB.A". On January 4, 2005, all of the subscription receipts were converted into Trust Units.

### **Significant Acquisitions**

We have not completed any significant acquisition during our most recently completed financial year for which disclosure is required under Part 8 of National Instrument 51-102.

## **DESCRIPTION OF OUR BUSINESS**

### **Overview**

Our principal undertaking is to issue Trust Units and to acquire and hold securities of subsidiaries, trusts and partnerships, net profits interests, royalties, notes and other interests. Our direct and indirect subsidiaries, trusts and partnerships carry on the business of acquiring, developing, exploiting and holding interests in petroleum and natural gas properties and assets related thereto. Cash flow from the properties is flowed to Bonavista by way of interest payments and principal repayments on notes, dividends from subsidiaries, payments from Bonavista Partnership under a net profits interest agreement, and from Bonavista Trust (2003) by way of interest payments, principal repayments and distributions.

The Board of Directors may declare cash distributions payable to the Unitholders and allocate any or all of our income to the Unitholders. It is currently anticipated that the only income we will receive will be from Bonavista Petroleum by way of interest and principal repayments received on the principal amount of notes, payments pursuant

to the NPI from Bonavista Partnership, and from Bonavista Trust (2003) by way of interest and principal repayments on the principal amount of notes and distributions. We make monthly cash distributions to Unitholders from this income after expenses and any cash redemptions of Trust Units.

Cash distributions are made on or about the 15<sup>th</sup> day of each month to Unitholders of record on or about the last calendar day of the immediately preceding month.

***Bonavista Petroleum Ltd.***

Bonavista Petroleum is a corporation amalgamated and subsisting pursuant to the laws of Alberta. Bonavista Petroleum is actively engaged directly and through its partnerships in the business of oil and natural gas exploration, development, acquisition and production in Canada.

We are the sole common shareholder of Bonavista Petroleum. The Exchangeable Shares are owned by the public.

The head office of Bonavista Petroleum is located at Suite 700, 311 – 6<sup>th</sup> Avenue S.W., Calgary, Alberta, T2P 3H2, and its registered office is located at Suite 1400, 350 – 7<sup>th</sup> Street S.W. Calgary, Alberta T2P 3N9.

***Bonavista Trust (2003)***

Bonavista Trust (2003) is a trust formed under the laws of Alberta. Bonavista Trust (2003) holds all the voting units of Bonavista Energy LP which is actively engaged in the business of oil and natural gas exploration, development, acquisition and production in Canada.

The principal and head office of Bonavista Trust (2003) is located at Suite 700, 311 – 6<sup>th</sup> Avenue S.W., Calgary, Alberta, T2P 3H2.

***Notes***

The Notes were issued by Bonavista Petroleum to us under the Note Indenture in connection with the Plan of Arrangement. The Notes are unsecured and bear interest at a rate of 14% per annum. Although Bonavista Petroleum is permitted to make payments against the principal amount of the Note outstanding from time to time without notice or bonus, Bonavista Petroleum is not required to make any payment in respect of principal until December 1, 2033, subject to extension in the limited circumstances provided in the Note Indenture. In contemplation of the possibility that Notes may be distributed to Unitholders upon the redemption of their Trust Units, the Note Indenture provides that if persons other than us (the "**Non-Fund Holders**") own Notes having an aggregate principal amount in excess of \$1,000,000, either we or the Non-Fund Holders shall be entitled, among other things, to require the Valiant Trust Company to exercise the powers and remedies available under the Note Indenture upon an event of default and, with us, the Non-Fund Holders may provide consents, waivers or directions relating generally to the variance of the Note Indenture and the rights of noteholders. The Note Indenture allows us flexibility to delay payments of interest or principal otherwise due to it while payment is made to other noteholders, and to allow other noteholders to be paid out before us. Any delayed payments will be due 5 days after demand.

From time to time we advance funds to our controlled entities which are evidenced by promissory notes. The terms of the notes are set at the time of issue. All of these advances are subordinate to all senior indebtedness to our senior lenders.

***NPI***

We are a party to a net profits interest agreement with Bonavista Partnership pursuant to which we have the right to receive the NPI on certain petroleum and natural gas rights held by Bonavista Partnership from time to time. Pursuant to the terms of the agreement, we are entitled to a payment from Bonavista Partnership for each month equal to the amount by which 99% of the gross proceeds from the sale of production attributable to the property interests of Bonavista Partnership for such month exceed ninety-nine (99%) percent of certain deductible costs for such period. The Bonavista Partnership is entitled to set off amounts reimbursable to it against NPI payments

payable by Bonavista Partnership. The term of the agreement is for so long as there are petroleum and natural gas rights to which the NPI applies.

### **Disclosure of Reserves Data and Other Oil and Natural Gas Information**

The statement of reserves data and other oil and natural gas information set forth below (the "**Statement**") is dated December 31, 2007. The effective date of the Statement is December 31, 2007 and the preparation date of the Statement by GLJ is February 26, 2008 and the preparation date of the Statement by Ryder Scott is March 4, 2008. The Report of Management and Directors on Reserves Data and Other Information Disclosure in Form 51-101F3 and the Report on Reserves Data by GLJ and Ryder Scott in Form 51-101F2 are attached as Appendices A, B and C to this Annual Information Form.

The reserves data set forth below is based upon an evaluation by GLJ and Ryder Scott with an effective date of December 31, 2007 and is a total summary of the GLJ Report, the Ryder Scott Report and an internal evaluation by Bonavista Petroleum Ltd. Of our total reserves, approximately 81% were evaluated by independent evaluators. The balance of approximately 19% of our proved plus probable reserves were evaluated internally and reviewed by GLJ on a proved plus probable net present value discounted at 10% basis. The reserves data summarizes our oil, liquids and natural gas reserves and the net present values of future net revenue for these reserves using forecast prices and costs. The reserves data conforms to the requirements of NI 51-101. No attempt was made to evaluate possible reserves.

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

**Due to uncertainties and lack of sufficient details with which to determine royalties for some product types under the proposed Alberta new royalty regime, the reserves data set forth below has been prepared using the existing royalties.** See "*Industry Conditions – Provincial Royalties and Incentives – Alberta*" and "*Risk Factors – Risks to Our Revenues – New Alberta Royalty Regime*". However, a low value sensitivity calculation with respect to the potential impact of the New Alberta Royalty Framework (the "**NRF**") is provided in the notes to certain of the reserves data tables set forth below.

**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 cost assumptions will be attained and variances could be material. The recovery and reserve estimates of 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. Readers should review the definitions and information contained in "*Definitions and Notes to Reserves Data Tables*" in conjunction with the following tables and notes. For more information as to the risks involved, see "*Risk Factors – Operational Risks – Reserves Estimates*" and "*Risk Factors – Risks to Our Revenues – Volatility of Oil and Natural Gas Prices*".**

**Reserves Data (Forecast Prices and Costs)**

**SUMMARY OF OIL AND NATURAL GAS RESERVES  
AND NET PRESENT VALUES OF FUTURE NET REVENUE  
AS OF DECEMBER 31, 2007  
FORECAST PRICES AND COSTS**

RESERVES CATEGORY	RESERVES					
	LIGHT AND MEDIUM OIL		HEAVY OIL		NATURAL GAS	
	Gross (Mbbls)	Net (Mbbls)	Gross (Mbbls)	Net (Mbbls)	Gross (Bcf)	Net (Bcf)
PROVED:						
Developed Producing	26,547	23,563	7,429	6,531	369,398	300,622
Developed Non-Producing	904	711	3,878	3,289	27,121	21,626
Undeveloped	5,944	4,880	719	633	26,825	20,969
TOTAL PROVED	33,396	29,154	12,027	10,453	423,344	343,217
PROBABLE	11,376	9,828	4,489	3,860	133,272	106,771
TOTAL PROVED PLUS PROBABLE	44,771	38,982	16,516	14,313	556,616	449,988

RESERVES CATEGORY	RESERVES			
	NATURAL GAS LIQUIDS		TOTAL RESERVES	
	Gross (Mbbls)	Net (Mbbls)	Gross (Mboe)	Net (Mboe)
PROVED:				
Developed Producing	15,649	12,036	111,191	92,234
Developed Non-Producing	961	728	10,264	8,332
Undeveloped	1,576	1,178	12,711	10,185
TOTAL PROVED	18,186	13,942	134,166	110,751
PROBABLE	6,332	4,835	44,409	36,319
TOTAL PROVED PLUS PROBABLE	24,518	18,777	178,575	147,070

RESERVES CATEGORY	NET PRESENT VALUES OF FUTURE NET REVENUE BEFORE INCOME TAXES DISCOUNTED AT (%/year) <sup>(2)(3)</sup>					UNIT VALUE BEFORE INCOME TAXES DISCOUNTED AT 10%/year <sup>(1)</sup>	
	0%	5%	10%	15%	20%	(\$/boe)	(\$/Mcf)
	(\$000s)	(\$000s)	(\$000s)	(\$000s)	(\$000s)		
PROVED:							
Developed Producing	3,703,701	2,713,299	2,187,349	1,857,602	1,629,114	23.72	3.95
Developed Non-Producing	261,743	200,645	160,762	133,310	113,443	19.29	3.22
Undeveloped	491,493	296,571	202,911	148,819	113,949	19.92	3.32
TOTAL PROVED	4,456,936	3,210,516	2,551,024	2,139,731	1,856,505	23.03	3.84
PROBABLE	1,659,039	905,749	602,748	445,686	350,737	16.59	2.77
TOTAL PROVED PLUS PROBABLE	6,115,975	4,116,265	3,153,772	2,585,416	2,207,242	21.44	3.57

Notes:

- (1) Unit values are based on net reserve volumes.
- (2) Management has estimated that the impact of the NRF is to decrease the net present values of future net revenue (before income taxes) by approximately 1% to 2% using a 10% discount rate and using the GLJ forecast prices set forth in this Annual Information Form. See "Industry Conditions – Provincial Royalties and Incentives – Alberta" and "Risk Factors – Risks to Our Revenues – The New Alberta Royalty Regime".
- (3) The methodology used to calculate the new royalties for the net present value of future net revenue amounts set forth in Note (1) was based on the following criteria: (i) in the case of heavy oil, a heavy oil par price was used for the high case and for the low case the light oil par price was used; (ii) application of the new conventional gas royalty formula on solution gas production was made; and (iii) in the case of deep gas, GLJ assumed that the deep gas royalty

adjustment applies to all existing and future wells in the high case and for the low case GLJ assumed that the deep gas royalty adjustment only applies to wells drilled after 2008.

RESERVES CATEGORY	NET PRESENT VALUES OF FUTURE NET REVENUE AFTER INCOME TAXES DISCOUNTED AT (%/year)				
	0% (\$000s)	5% (\$000s)	10% (\$000s)	15% (\$000s)	20% (\$000s)
PROVED:					
Developed Producing	3,401,011	2,550,010	2,086,512	1,789,953	1,581,133
Developed Non-Producing	217,138	169,696	138,270	116,333	100,243
Undeveloped	386,417	238,934	166,430	123,713	95,718
TOTAL PROVED	4,004,566	2,958,640	2,391,211	2,030,000	1,777,094
PROBABLE	1,258,035	707,287	482,835	364,824	292,408
TOTAL PROVED PLUS PROBABLE	5,262,601	3,665,926	2,874,047	2,394,824	2,069,503

**TOTAL FUTURE NET REVENUE  
(UNDISCOUNTED)  
AS OF DECEMBER 31, 2007  
FORECAST PRICES AND COSTS**

RESERVES CATEGORY	REVENUE (\$000s)	ROYALTIES (\$000s)	OPERATING COSTS (\$000s)	DEVELOPMENT COSTS (\$000s)	WELL ABANDONMENT COSTS (\$000s)	FUTURE NET REVENUE BEFORE INCOME TAXES (\$000s)	INCOME TAXES (\$000s)	FUTURE NET REVENUE AFTER INCOME TAXES (\$000s)
PROVED:								
Developed Producing	6,565,777	1,064,334	1,690,740	19,097	87,905	3,703,701	302,690	3,401,011
Developed Non-Producing	526,985	96,985	134,318	27,616	6,322	261,743	44,606	217,138
Undeveloped	864,531	160,845	120,465	87,158	4,570	491,493	105,075	386,417
TOTAL PROVED	7,957,292	1,322,164	1,945,523	133,872	98,797	4,456,936	452,370	4,004,566
PROBABLE	2,908,247	493,735	666,308	75,816	13,350	1,659,039	401,003	1,258,035
TOTAL PROVED PLUS PROBABLE	10,865,539	1,815,899	2,611,831	209,688	112,147	6,115,975	853,374	5,262,601

**FUTURE NET REVENUE  
BY PRODUCTION GROUP  
AS OF DECEMBER 31, 2007  
FORECAST PRICES AND COSTS**

RESERVES CATEGORY	PRODUCTION GROUP	FUTURE NET REVENUE BEFORE INCOME TAXES (discounted at 10%/year) <small>(2),(3)</small>	UNIT VALUE <sup>(1)</sup>	
		(\$000s)	(\$/boe)	(\$/Mcfe)
Proved	Light and Medium Crude Oil (including solution gas and other by-products)	827,057	28.76	4.79
	Heavy Oil (including solution gas and other by-products)	243,081	23.05	3.84
	Natural Gas (including by-products but excluding natural gas from oil wells)	1,480,886	20.73	3.45
	Total	2,551,024	23.03	3.84
Proved plus Probable	Light and Medium Crude Oil (including solution gas and other by-products)	1,030,468	26.07	4.35
	Heavy Oil (including solution gas and other by-products)	315,993	21.91	3.65
	Natural Gas (including by-products but excluding natural gas from oil wells)	1,807,311	19.41	3.23
	Total	3,153,772	21.44	3.57

## Notes:

- (1) Unit values are based on net reserve volumes.
- (2) Management has estimated that the impact of the NRF is to decrease the net present values of future net revenue (before income taxes) by approximately 1% to 2% using a 10% discount rate and using the GLJ forecast prices set forth in this Annual Information Form. See "*Industry Conditions – Provincial Royalties and Incentives – Alberta*" and "*Risk Factors – Risks to Our Revenues – The New Alberta Royalty Regime*".
- (3) The methodology used to calculate the new royalties for the net present value of future net revenue amounts set forth in Note (1) was based on the following criteria: (i) in the case of heavy oil, a heavy oil par price was used for the high case and for the low case the light oil par price was used; (ii) application of the new conventional gas royalty formula on solution gas production was made; and (iii) in the case of deep gas, GLJ assumed that the deep gas royalty adjustment applies to all existing and future wells in the high case and for the low case GLJ assumed that the deep gas royalty adjustment only applies to wells drilled after 2008.

## Definitions and Other Notes to Reserves Data Tables

In the tables set forth above in "*Disclosure of Reserves Data and Other Oil and Natural Gas Information*" and elsewhere in this Annual Information Form the following definitions and other notes are applicable:

1. **"Gross"** means:
  - (a) in relation to our interest in production and reserves, our interest (operating and non-operating) share before deduction of royalties and without including any of our royalty interests;
  - (b) in relation to wells, the total number of wells in which we have an interest; and
  - (c) in relation to properties, the total area of properties in which we have an interest.
  
2. **"Net"** means:
  - (a) in relation to our interest in production and reserves, our interest (operating and non-operating) share after deduction of royalty obligations, plus our royalty interest in production or reserves.
  - (b) in relation to wells, the number of wells obtained by aggregating our working interest in each of our gross wells; and
  - (c) in relation to our interest in a property, the total area in which we have an interest multiplied by our working interest.
  
3. Definitions used for reserve categories are as follows:

### *Reserve Categories*

Reserves are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, from a given date forward, based on

- (a) analysis of drilling, geological, geophysical and engineering data;
- (b) the use of established technology; and
- (c) specified economic conditions (see the discussion of "*Economic Assumptions*" below).

Reserves are classified according to the degree of certainty associated with the estimates.

- (a) Proved reserves are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.
- (b) Probable reserves are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves.

**"Economic Assumptions"** means the forecast prices and costs used in the estimate:

### *Development and Production Status*

Each of the reserve categories (proved and probable) may be divided into developed and undeveloped categories:

- (a) Developed reserves are those reserves that are expected to be recovered from existing wells and installed facilities or, if facilities have not been installed, that would involve a low expenditure (for example, when compared to the cost of drilling a well) to put the reserves on production. The developed category may be subdivided into producing and non-producing.
  - (i) Developed producing reserves are those reserves that are expected to be recovered from completion intervals open at the time of the estimate. These reserves may be currently producing or, if shut-in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainty.
  - (ii) Developed non-producing reserves are those reserves that either have not been on production, or have previously been on production, but are shut-in, and the date of resumption of production is unknown.
- (b) Undeveloped reserves are those reserves expected to be recovered from known accumulations where a significant expenditure (for example, when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves classification (proved, probable) to which they are assigned.

In multi-well pools it may be appropriate to allocate total pool reserves between the developed and undeveloped categories or to subdivide the developed reserves for the pool between developed producing and developed non-producing. This allocation should be based on the estimator's assessment as to the reserves that will be recovered from specific wells, facilities and completion intervals in the pool and their respective development and production status.

### *Levels of Certainty for Reported Reserves*

The qualitative certainty levels referred to in the definitions above are applicable to individual reserve entities (which refers to the lowest level at which reserves calculations are performed) and to reported reserves (which refers to the highest level sum of individual entity estimates for which reserves are presented). Reported reserves should target the following levels of certainty under a specific set of economic conditions:

- (a) at least a 90 percent probability that the quantities actually recovered will equal or exceed the estimated proved reserves; and
  - (b) at least a 50 percent probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable reserves.
  - (c) A qualitative measure of the certainty levels pertaining to estimates prepared for the various reserves categories is desirable to provide a clearer understanding of the associated risks and uncertainties. However, the majority of reserves estimates will be prepared using deterministic methods that do not provide a mathematically derived quantitative measure of probability. In principle, there should be no difference between estimates prepared using probabilistic or deterministic methods.
4. "**Development costs**" means costs incurred to obtain access to reserves and to provide facilities for extracting, treating, gathering and/or storing the oil and gas from reserves. More specifically, development costs, including applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to:

- (a) gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground draining, road building, and relocating public roads, gas lines and power lines, pumping equipment and wellhead assembly;
  - (b) drill and equip development wells, development type stratigraphic test wells and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment and wellhead assembly;
  - (c) acquire, construct and install production facilities such as flow lines, separators, treaters, heaters, manifolds, measuring devices and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems; and
  - (d) provide improved recovery systems.
5. **"Development well"** means a well drilled inside the established limits of an oil and gas reservoir, or in close proximity to the edge of the reservoir, to the depth of a stratigraphic horizon known to be productive.
6. **"Exploration costs"** means costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects that may contain oil and gas reserves, including costs of drilling exploratory wells and exploratory type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property and after acquiring the property. Exploration costs, which include applicable operating costs of support equipment and facilities and other costs of exploration activities, are:
- (a) costs of topographical, geochemical, geological and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews and others conducting those studies;
  - (b) costs of carrying and retaining unproved properties, such as delay rentals, taxes (other than income and capital taxes) on properties, legal costs for title defence, and the maintenance of land and lease records;
  - (c) dry hole contributions and bottom hole contributions;
  - (d) costs of drilling and equipping exploratory wells; and
  - (e) costs of drilling exploratory type stratigraphic test wells.
7. **"Exploratory well"** means a well that is not a development well, a service well or a stratigraphic test well.
8. **"Service well"** means a well drilled or completed for the purpose of supporting production in an existing field. Wells in this class are drilled for the following specific purposes: gas injection (natural gas, propane, butane or flue gas), water injection, steam injection, air injection, salt water disposal, water supply for injection, observation or injection for combustion.

9. **"Forecast Prices and Costs"**

These are prices and costs that are:

- (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 Bonavista is 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).

10. Numbers may not add due to rounding.

11. The estimates of future net revenue presented in the tables above do not represent fair market value.

**Pricing Assumptions**

**SUMMARY OF PRICING AND INFLATION RATE ASSUMPTIONS  
AS OF DECEMBER 31, 2007  
FORECAST PRICES AND COSTS <sup>(1)(2)(3)(4)</sup>**

Year	OIL				NATURAL GAS			Edmonton Propane (\$Cdn/bbl)	Edmonton Butane (\$Cdn/bbl)	Edmonton Pentane Plus (\$Cdn/bbl)
	WTI Cushing Oklahoma (\$US/bbl)	Edmonton Par Price 40° API (\$Cdn/bbl)	Hardisty Heavy 12° API (\$Cdn/bbl)	Cromer Medium 29.3° API (\$Cdn/bbl)	AECO Natural Gas Price (\$Cdn/MMbtu)	Spec Ethane (\$Cdn/bbl)	Edmonton Propane (\$Cdn/bbl)			
2008	92.00	91.10	54.02	79.26	6.75	22.73	58.30	72.88	92.92	
2009	88.00	87.10	51.61	75.78	7.55	25.49	55.74	69.68	88.84	
2010	84.00	83.10	49.19	72.30	7.60	25.66	53.18	66.48	84.76	
2011	82.00	81.10	47.98	70.56	7.60	25.66	51.90	64.88	82.72	
2012	82.00	81.10	47.98	70.56	7.60	25.66	51.90	64.88	82.72	
2013	82.00	81.10	49.04	70.56	7.60	25.66	51.90	64.88	82.72	
2014	82.00	81.10	50.09	70.56	7.80	26.35	51.90	64.88	82.72	
2015	82.00	81.10	51.15	70.56	7.97	26.94	51.90	64.88	82.72	
2016	82.02	81.12	52.21	70.57	8.14	27.52	51.91	64.89	82.74	
2017	83.66	82.76	53.29	72.00	8.31	28.11	52.97	66.21	84.42	
2018	85.33	84.42	54.36	73.44	8.48	28.67	54.03	67.53	86.11	
Thereafter	2%/year	2%/year	2%/year	2%/year	2%/year	2%/year	2%/year	2%/year	2%/year	

Notes:

- (1) This summary table identifies benchmark reference pricing schedules that might apply to a reporting issuer.
- (2) Exchange rate is 1.00 \$US/\$Cdn and is used to generate the benchmark reference prices in this table.
- (3) The pricing forecast used in determining the value of cash flow is based on the January 1, 2008 forecast determined by GLJ.
- (4) Inflation rate is 2.00% per year.

Weighted average historical prices we realized for the year ended December 31, 2007, were \$6.95/Mcf for natural gas, \$66.58/bbl for light and medium oil, \$43.94/bbl for natural gas liquids and \$45.20/bbl for heavy oil.

**Reserves Reconciliation**

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

	LIGHT AND MEDIUM OIL			HEAVY OIL		
	Proved (Mbbls)	Probable (Mbbls)	Proved Plus Probable (Mbbls)	Proved (Mbbls)	Probable (Mbbls)	Proved Plus Probable (Mbbls)
<b>December 31, 2006</b>	32,795	10,107	42,903	13,132	4,695	17,827
Discoveries	-	-	-	-	-	-
Extensions	1,180	759	1,939	1,989	492	2,482
Infill Drilling	-	-	-	518	235	752
Improved Recovery	423	82	505	485	108	593
Technical Revisions	987	61	1,048	(1,347)	(1,041)	(2,388)
Acquisitions	1,898	367	2,265	-	-	-
Economic Factors	-	-	-	-	-	-
Production	(3,888)	-	(3,888)	(2,749)	-	(2,749)
<b>December 31, 2007</b>	<u>33,396</u>	<u>11,376</u>	<u>44,772</u>	<u>12,027</u>	<u>4,489</u>	<u>16,516</u>

	ASSOCIATED AND NON-ASSOCIATED GAS			NATURAL GAS LIQUIDS		
	Proved (MMcf)	Probable (MMcf)	Proved Plus Probable (MMcf)	Proved (Mbbls)	Probable (Mbbls)	Proved Plus Probable (Mbbls)
<b>December 31, 2006</b>	427,915	114,558	542,472	17,664	5,154	22,817
Discoveries	153	93	246	-	-	-
Extensions	21,445	9,922	31,366	1,049	660	1,709
Infill Drilling	807	615	1,422	51	42	92
Improved Recovery	10,474	(388)	10,085	564	(26)	539
Technical Revisions	1,886	4,090	5,975	(199)	271	72
Acquisitions	22,864	4,383	27,248	1,173	232	1,405
Economic Factors	-	-	-	-	-	-
Production	(62,198)	-	(62,198)	(2,117)	-	(2,117)
<b>December 31, 2007</b>	<u>423,344</u>	<u>133,272</u>	<u>556,616</u>	<u>18,186</u>	<u>6,332</u>	<u>24,518</u>

	OIL EQUIVALENT		
	Proved (Mboe)	Probable (Mboe)	Proved Plus Probable (Mboe)
<b>December 31, 2006</b>	134,910	39,049	173,959
Discoveries	25	16	41
Extensions	7,793	3,565	11,358
Infill Drilling	703	378	1,081
Improved Recovery	3,218	100	3,318
Technical Revisions	(244)	(28)	(272)
Acquisitions	6,882	1,329	8,211
Economic Factors	-	-	-
Production	(19,121)	-	(19,121)
<b>December 31, 2007</b>	<u>134,166</u>	<u>44,409</u>	<u>178,575</u>

## Additional Information Relating to Reserves Data

### Undeveloped Reserves

Undeveloped reserves are attributed by GLJ and Ryder Scott in accordance with standards and procedures contained in the COGE Handbook. Proved undeveloped reserves are those reserves that can be estimated with a high degree of certainty and are expected to be recovered from known accumulations where a significant expenditure is required to render them capable of production. Probable undeveloped reserves are those reserves that are less certain to be recovered than proved reserves and are expected to be recovered from known accumulations where a significant expenditure is required to render them capable of production.

There are a number of factors that could result in delayed or cancelled development, including the following: (i) changing economic conditions (due to pricing, operating and capital expenditure fluctuations); (ii) changing technical conditions (including production anomalies, such as water breakthrough or accelerated depletion); (iii) multi-zone developments (for instance, a prospective formation completion may be delayed until the initial completion is no longer economic); (iv) a larger development program may need to be spread out over several years to optimize capital allocation and facility utilization; and (v) surface access issues (including those relating to land owners, weather conditions and regulatory approvals). For more information, see "*Risk Factors*".

### Proved Undeveloped Reserves

The following table discloses, for each product type, the volumes of proved undeveloped reserves that were attributed in each of the most recent three financial years and, in the aggregate, before that time.

**TIMING OF INITIAL PROVED UNDEVELOPED RESERVES ASSIGNMENT  
GROSS RESERVES FIRST ATTRIBUTED BY YEAR**

Year	Light and Medium Oil (Mbbbls)		Heavy Oil (Mbbbls)		Natural Gas (MMcf)		NGLs (Mbbbls)	
	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	5,097	5,097	455	455	11,558	11,558	497	497
2005	-	5,097	-	455	1,292	12,850	42	539
2006	-	5,097	-	455	3,483	16,333	433	972
2007	847	5,944	264	719	10,492	26,825	605	1,576

Of our total proved plus probable reserves, 12.7 MMboe or 7% are proved undeveloped reserves. The Lethbridge property accounts for 5.1 MMboe or 40% of our proved undeveloped reserves. Following Lethbridge, the Blueberry property which is located in British Columbia and the Willesden Green property acquired in 2007 accounted for 1.7 and 0.8 MMboe of these undeveloped reserves, respectively. In 2008 and 2009 capital expenditures of \$39.0 million and \$29.3 million will be invested on these proved undeveloped reserves. Of this \$68.3 million, \$12.8 million will be spent in Lethbridge, \$10 million on our Northeast British Columbia properties, \$7.4 million on our Willesden Green property and \$6.2 million at Lanaway. There have been no proved undeveloped reserves booked on our Southeast Saskatchewan Bakken property, however we are planning to spend approximately \$40 million in this area in 2008.

### Probable Undeveloped Reserves

The following table discloses, for each product type, the volumes of probable undeveloped reserves that were first attributed in each of the most recent three financial years and, in the aggregate, before that time.

TIMING OF INITIAL PROBABLE UNDEVELOPED RESERVES ASSIGNMENT GROSS RESERVES FIRST ATTRIBUTED BY YEAR								
Year	Light and Medium Oil (Mbbls)		Heavy Oil (Mbbls)		Natural Gas (MMcf)		NGLs (Mbbls)	
	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	2,923	2,923	124	124	9,700	9,700	593	593
2005	9	2,931	47	171	3,396	13,096	183	776
2006	-	2,931	-	171	1,703	14,799	98	874
2007	650	3,583	129	300	6,934	21,733	394	1,268

Probable undeveloped reserves account for 8.8 MMBoe or 5% of the total proved plus probable reserves. In 2008 and 2009 capital expenditures of \$10.2 million and \$20.1 million will be invested on these probable undeveloped reserves. Of this \$30.3 million of capital expenditure, \$13.7 million will be spent in our Northeast British Columbia Region, \$4.3 million at Sundre, \$3.2 million at Valhalla and \$2.1 million in the Tweedie/Wappau area. There have been no probable undeveloped reserves booked at our Willesden Green property nor for our Southeast Saskatchewan Bakken property.

### Significant Factors or Uncertainties

Our evaluated oil and natural gas properties have no material extraordinary risks or uncertainties beyond those, which are inherent in an oil and natural gas producing company as described under the heading "*Management's Discussion and Analysis*" in our 2008 Management's Discussion and Analysis that has been mailed to our Unitholders and is available on SEDAR at [www.sedar.com](http://www.sedar.com). See also "*Risk Factors*" below.

### Future Development Costs

The following table sets forth development costs deducted in the estimation of our future net revenue attributable to the reserve categories noted below.

Year	FORECAST PRICES AND COSTS	
	Proved Reserves (\$000s)	Proved Plus Probable Reserves (\$000s)
2008	58,560	75,173
2009	38,669	63,096
2010	16,754	30,937
2011	10,726	18,925
2012	2,046	7,825
Remaining	7,117	13,732
Total (Undiscounted)	133,872	209,688

We expect to fund the development costs of our reserves through a combination of internally generated cash flow, debt and the issuance of Trust Units or other securities. We withhold approximately 40 to 50% of cash flow to assist in funding development activities.

There can be no guarantee that funds will be available or that the Board of Directors will allocate funding to develop all of the reserves attributed in the reserve reports. Failure to develop those reserves would have a negative impact on future cash flow.

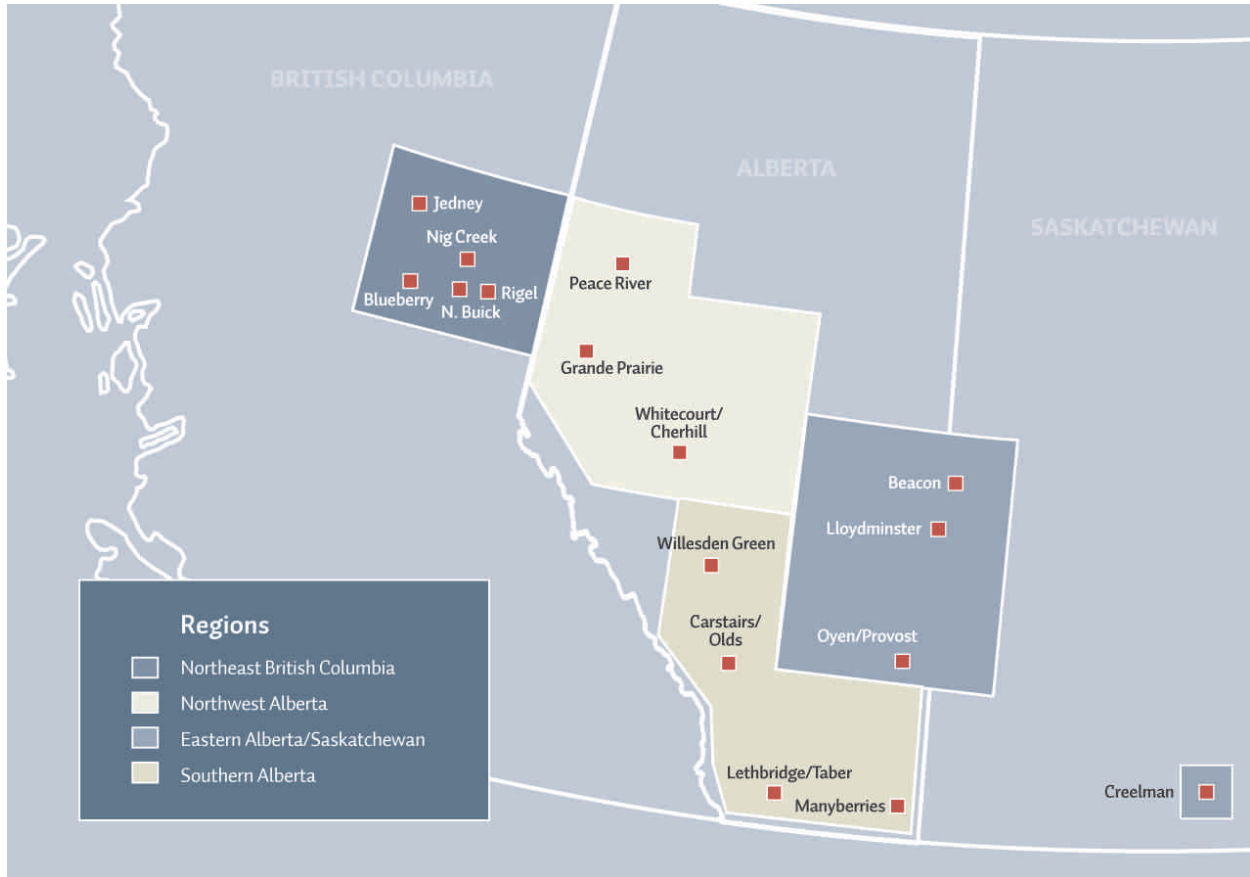
The interest or other costs of external funding are not included in the reserves and future net revenue estimates and would reduce reserves and future net revenue to some degree depending upon the funding sources utilized. We do not anticipate that interest or other funding costs would make development of any property uneconomic.

## Other Oil and Natural Gas Information

### *Oil and Natural Gas Properties*

The following is a description of our principal oil and natural gas properties on production or under development as at December 31, 2007. The term "net", when used to describe our share of production, means the total of our working interest share before deduction of royalties owned by others. Reserve amounts are stated, before deduction of royalties, at December 31, 2007, based on December 31, 2007 forecast price and cost assumptions. Unless otherwise specified, gross and net acres and well count information are as at December 31, 2007. **The estimates of reserves 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.**

Our major properties are concentrated in four regions within Alberta, British Columbia and Saskatchewan. Each region offers a large undeveloped land base, a vast seismic database, and significant ownership and operatorship in production facilities.



## MAJOR PROPERTIES

	CURRENT PRODUCTION	UNDEVELOPED LAND	GROSS RESERVES	2008 DRILLING PROGRAM
NORTHEAST B.C. REGION	(boe/d)	(net acres)	(MMboe)	(# of locations)
Rigel	2,400	61,300	12.0	-
Nig Creek/N. Buick	5,000	105,600	23.0	8
Jedney/Blueberry	2,700	22,100	12.7	2
<b>Total Northeast B.C. Region</b>	<b>10,100</b>	<b>189,000</b>	<b>47.7</b>	<b>10</b>

	CURRENT PRODUCTION	UNDEVELOPED LAND	GROSS RESERVES	2008 DRILLING PROGRAM
NORTHWEST AB. REGION	(boe/d)	(net acres)	(MMboe)	(# of locations)
Peace River	6,000	116,000	14.6	11
Grand Prairie	2,000	84,000	10.8	4
Whitecourt/Cherhill	2,300	87,200	5.4	5
<b>Total Northwest Alberta Region</b>	<b>10,300</b>	<b>287,200</b>	<b>30.8</b>	<b>20</b>

	CURRENT PRODUCTION	UNDEVELOPED LAND	GROSS RESERVES	2008 DRILLING PROGRAM
EASTERN REGION	(boe/d)	(net acres)	(MMboe)	(# of locations)
Lloydminster (Heavy oil)	7,500	48,300	14.6	52
Oyen/Provost	3,800	94,800	10.7	56
Beacon Hills	3,100	158,600	7.7	24
Southeast Saskatchewan	800	34,200	0.7	18
<b>Total Eastern Region</b>	<b>15,200</b>	<b>335,900</b>	<b>33.7</b>	<b>150</b>

	CURRENT PRODUCTION	UNDEVELOPED LAND	GROSS RESERVES	2008 DRILLING PROGRAM
SOUTHERN AB. REGION	(boe/d)	(net acres)	(MMboe)	(# of locations)
Lethbridge/Taber	4,100	47,000	19.9	8
Carstairs/Olds	8,700	133,000	34.0	11
Willesden Green	6,300	61,000	10.2	15
Manyberries	900	17,000	2.3	1
<b>Total Southern Alberta Region</b>	<b>20,000</b>	<b>258,000</b>	<b>66.4</b>	<b>35</b>

<b>Grand Total</b>	<b>55,600</b>	<b>1,070,100</b>	<b>178.6</b>	<b>215</b>
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*Northeast British Columbia Region*

The Northeast British Columbia Region was created as a result of the acquisition of oil and natural gas properties in the Fort St. John area on December 31, 2004. This region represents approximately 24% of our current natural gas production and 12% of our oil and liquids production. This production is derived from productive formations within the Mississippian, Triassic and Cretaceous aged sands.

Production from the area is produced mainly through our 14 owned and operated compression facilities. Our average working interest in these facilities is approximately 87%. As virtually all natural gas produced in this area of British Columbia is processed and shipped to market by Duke Energy Gas Transmission, we do not own direct interests in natural gas processing plants. In 2007, production from the Northeast British Columbia Region averaged 44.2 MMcf/d of natural gas and 3,085 bbls/d of oil and liquids for a total of 10,455 boe/d. We also own 189,000 net acres of highly prospective undeveloped land in the region with an average working interest of approximately 65%.

The Northeast British Columbia Region includes a diversified property base, mostly operated by Bonavista Petroleum, which in 2007 collectively accounted for:

- 14% of total exploration and development expenditures;
- 0% of total acquisition expenditures;
- 18% of current total production volumes;
- 27% of proved plus probable reserves at December 31, 2007; and
- 18% of undeveloped land holdings at December 31, 2007.

In 2007, we spent \$38.4 million on exploration and development capital, this amount included the drilling of 18 wells. In 2008, we expect to spend approximately \$28.4 million in the Northeast British Columbia Region, which includes drilling and equipping 10 new wells. These capital expenditures are expected to result in production remaining steady for 2008.

#### Major Properties

Our Northeast British Columbia Region is comprised of Rigel, Nig Creek/N. Buick and Jedney/Blueberry, which are all geographically located within a 200 mile radius of Fort St. John, British Columbia.

Rigel – The Rigel area currently produces 2,400 boe/d, primarily natural gas and liquids. In 2008 we plan to invest in recompletion/workovers and compression projects for total capital expenditures of approximately \$1.5 million.

Nig Creek/N. Buick – In 2007, we drilled 16 wells: 15 were cased as natural gas wells and one as an oil well. The area currently produces 5,000 boe/d, primarily natural gas and liquids. The Nig Creek/N. Buick area is comprised of the Nig Creek, N. Buick and Fireweed properties. In 2008, we expect to drill 8 wells, tie in some standing wells, and optimize compression. We plan to spend a total of \$13.5 million of which \$10.4 million will be spent on drilling wells and \$3.1 million on recompletions/workovers/compression projects, potentially adding 500 boe/d.

Blueberry/Jedney – In 2007, we drilled two wells, resulting in a significant Debolt and Halfway gas well. In the Blueberry/Jedney area we currently produce 2,700 boe/d, primarily natural gas and liquids with over 300 bbls/d of oil from the Inga area. In 2008 we plan to spend approximately \$6.9 million, drilling one Debolt delineation well and performing minor workovers which should collectively add approximately 300 boe/d.

#### *Northwest Alberta Region*

The Northwest Alberta Region represents approximately 25% of our current natural gas production and 11% of our oil and liquids production. This production is derived from many productive formations within the Mississippian, Triassic, Jurassic and Cretaceous aged sands.

In 2007, production from the Northwest Alberta Region averaged 44.8 MMcf/d of natural gas and 2,778 bbls/d of light oil and liquids for a total of 10,242 boe/d. We also own 287,200 net acres of undeveloped land in the region with an average working interest of 76%.

During 2007, we invested \$45.0 million on exploration and development capital expenditures, which included drilling 19 wells, resulting in 14 natural gas wells and three oil wells. In 2008, we are planning to spend approximately \$40.2 million on development activities with expected production to average 10,600 boe/d.

The Northwest Alberta Region includes a diversified property base, mostly operated by Bonavista Petroleum, which in 2007 collectively accounted for:

- 18% of total exploration and development expenditures;
- 0% acquisition expenditures;
- 19% of current total production volumes;
- 17% of proved plus probable reserves at December 31, 2007; and
- 27% of undeveloped land holdings at December 31, 2007.

#### Major Properties

Peace River – In 2007, we drilled eight wells on the Peace River property resulting in six natural gas wells and two oil wells. This area currently produces 6,000 boe/d. In 2008 we plan to drill 11 wells in the area spending approximately \$17.7 million to maintain current production levels.

Grande Prairie – In 2007, we drilled six wells on the Grande Prairie lands resulting in four natural gas wells and one oil well. This area currently produces approximately 2,000 boe/d. In 2008, we plan to drill four wells in the area, total capital spending is estimated at \$11.7 million adding approximately 350 boe/d.

With 200,000 net acres of undeveloped land currently in the Peace River and Grande Prairie area, inventory of high quality drilling locations and over 65 MMcf/d of operated plant capacity, production volumes should remain relatively flat over the next several years.

Whitecourt/Cherhill – In the Whitecourt/Cherhill area, we participated in five wells resulting in five natural gas wells. This area currently produces approximately 2,300 boe/d. There are 87,200 net acres of highly prospective undeveloped land and currently over 15 identified drilling prospects. In 2008, we plan to spend approximately \$10.1 million participating in drilling five wells and compression and workovers projects. We anticipate that production levels will remain relatively flat with this level of capital investment.

#### *Eastern Region*

The Eastern Region represents approximately 19% of our current natural gas production, 100% of our heavy oil production, and 37% of our total oil and liquids production. Natural gas and heavy oil production is derived from a multitude of Upper and Lower Cretaceous sands.

Production from the Eastern Region in 2007 averaged 39.8 MMcf/d of natural gas, 7,548 bbls per day of heavy oil and 1,434 bbls per day of light and medium oil, for a total of 15,611 boe/d. Bonavista Petroleum operates 22 natural gas and oil facilities in the Eastern Region.

During 2007, we invested \$78.6 million in the Eastern Region. This investment included the drilling of 137 wells with a 94% success rate, resulting in 49 natural gas wells, 37 medium gravity wells and 43 heavy oil wells. At December 31, 2007, undeveloped land in the area was 335,900 net acres, with an average working interest of 67.5%. In 2007, Bonavista invested \$19.0 million to expand its land position in the Bakken play in the Southeast Saskatchewan area.

The Eastern Region in 2007 collectively accounted for:

- 29% of total exploration and development expenditures;
- 0% of total acquisition expenditures;
- 27% of current total production volumes;
- 19% of proved plus probable reserves at December 31, 2007; and
- 31% of undeveloped land at December 31, 2007.

In 2008, we plan to invest \$104.3 million in the Eastern Region to drill 150 wells. The low risk nature of the area creates a high degree of certainty with these drilling prospects. The Eastern Region is forecasted to average 15,200 boe/d in 2008 with this level of capital activity.

### Major Properties

Lloydminster – We have been operating in the Lloydminster area for seven years commencing with an acquisition of 6,220 bbls/d of heavy oil in 2001. Since that time, we have engaged in an active and successful heavy oil drilling program, resulting in current production of approximately 7,500 boe/d. These assets are geographically concentrated and highly productive heavy oil properties with operating costs of approximately \$12.50/bbl and forecasted finding and development costs of \$12.00/bbl. In 2008, with plans to spend \$44.2 million drilling 52 wells and performing workovers, we expect to average approximately 7,900 boe/d.

Oyen/Provost – The greater Provost area accounts for 25% of the Eastern Region's production. This stable natural gas and crude oil production is currently producing 3,800 boe/d and is derived primarily from the shallow Cretaceous sands prevalent throughout the area. Bonavista Petroleum operates or has an interest in several natural gas facilities and pipeline gathering systems in the area, resulting in low cost reserve and production additions in 2008 and beyond. In 2008, we plan to spend \$13.7 million, drilling 56 wells and performing workovers adding approximately 700 boe/d.

Beacon Hills – We have been successfully developing shallow gas in this area for the past nine years with current production at 3,100 boe/d. Extensive use of 2D seismic over this period has resulted in a drilling success rate of 97% and has led to stable natural gas production from the area. In 2008, we plan to spend \$2.4 million, which should result in an additional 140 boe/d of production.

Southeast Saskatchewan – In late 2006, we completed the uphole Bakken zone in a deeper Red River producing well at Creelman, an area that was deemed to be off the main emerging Bakken fairway. Based on favourable test results we embarked on a crown and freehold land acquisition program acquiring 49 prospective sections. Recent industry exploration activity in close proximity to these lands has proven the Bakken to be productive. In 2008, Bonavista will spend \$41.3 million to drill, complete and equip 18 horizontal Bakken oil wells.

### *Southern Alberta Region*

The Southern Alberta Region represents approximately 32% of our current natural gas production and 40% of our oil and liquids production. Production originates from multiple formations as deep as the Wabamum formation in the Olds area and as shallow as the Edmonton sands in the Sylvan Lake area. Recent focus has been on medium to deep oil and liquids rich gas productive formations.

Production from the Southern Alberta Region in 2007 averaged 42.1 MMcf/d of natural gas and 9,189 bbls/d of light oil and liquids for a total of 16,197 boe/d. We also own 258,000 net acres of undeveloped land in the region with an average working interest of 72%.

During 2007, we invested \$204.0 million of capital in the Southern Alberta Region including \$99.0 million directed toward property acquisitions and \$105.0 million on exploration and development. This exploration and development program resulted in 28 natural gas wells and 13 oil wells for an overall success rate of 97%.

The Southern Alberta Region includes a balanced property base of shallow and deep potential, both oil and natural gas, mostly operated by Bonavista Petroleum, which in 2007 collectively accounted for:

- 39% of total exploration and development expenditures;
- 100% of total acquisition expenditures;
- 36% of current total production volumes;
- 37% of proved plus probable reserves at December 31, 2007; and
- 24% of undeveloped land holdings at December 31, 2007.

In 2008, we plan capital expenditures of \$247.0 million in the Southern Alberta Region. This consists of approximately \$170 million on acquisitions and the balance on a 35 well drilling program. With this capital spending, we anticipate production additions of approximately 6,400 boe/d. In 2008, we expect the average production to be 19,100 boe/d for this area.

#### Major Properties

Lethbridge – In 1999, we made a discovery of light oil within the Barons sand by recompleting a well originally drilled for Bow Island natural gas. The pool is currently producing 1,650 bbls/d of light 39° API oil responding favourably after a full-field three year waterflood was initiated in 2004. The Barons pool is a long-life asset with considerable upside potential under the waterflood scheme. In 2008, we plan to drill four in-fill wells on this Barons trend. We expect to spend \$8.9 million in the greater area to drill a total of eight oil wells. We currently produce approximately 4,100 boe/d in the Lethbridge area.

Carstairs/Olds – We entered the Carstairs area in 2002 through a major acquisition and since that time we have been aggressively expanding this long-life area through smaller complementary acquisitions and a steady drilling program. In 2008, we expect to drill 11 wells in the greater Carstairs area and spend \$28.0 million on development activities. These expenditures would result in approximately 1,180 boe/d of additional volumes. This area presents significant opportunity resulting from the combination of our current land base of 133,000 net undeveloped acres and the multi-zone potential associated with these lands. We currently produce 8,700 boe/d in this area.

Willesden Green – Since 2003, Bonavista has been establishing a land position and production base through crown land sales and small property acquisitions in this multizone liquids rich productive zone area. In the third quarter of 2007 we spent \$78.3 million to acquire low decline production and an operated working interest in a 12 MMcf/d natural gas plant and associated pipelines. Control of this infrastructure will greatly facilitate growth through drilling and acquisition. With this acquisition and the drilling of six natural gas wells, production in the area grew to 2,500 boe/d at year end. In 2008, we will invest approximately \$27.0 million to drill 15 wells and associated development activities adding approximately 1,170 boe/d of additional volumes.

Manyberries – The Manyberries property was acquired in three phases between 1999 and 2002 and is currently producing 900 boe/d, consisting primarily of high netback light oil. The production originates from several mature oil pools under secondary water flood recovery schemes. As the waterflood programs are optimized, long-term stable production is anticipated with up to 40% of the original oil in place likely to be recovered ultimately from these pools. We expect to spend \$8.6 million in this area, which includes drilling one horizontal well.

### **Oil and Natural Gas Wells**

The following table sets forth the number and status of wells in which we had a working interest as at December 31, 2007.

	Oil Wells				Natural Gas Wells			
	Producing		Non-Producing		Producing		Non-Producing	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Alberta	1,441	1,166	1,853	938	1,661	1,131	1,934	1,078
British Columbia	12	6	84	56	339	249	428	353
Saskatchewan	82	70	90	47	77	70	175	108
Total	1,535	1,242	2,027	1,041	2,077	1,450	2,537	1,539

### **Properties with No Attributable Reserves**

The following table sets out our undeveloped land holdings as at December 31, 2007.

	Undeveloped Acres	
	Gross	Net
Alberta	1,054,300	685,000
British Columbia	299,000	189,000
Saskatchewan	215,700	196,100
Total	1,569,000	1,070,100

We expect that rights to explore, develop and exploit approximately 154,000 net acres of our undeveloped land holdings may expire on or before December 31, 2008. There are no material drilling commitments associated with the land holdings expiring by December 31, 2008.

### **Forward Contracts**

We are exposed to market risks resulting from fluctuations in commodity prices, foreign exchange rates and interest rates in the normal course of operations. A variety of derivative instruments are used to reduce our exposure to fluctuations in commodity prices and foreign exchange rates. We are exposed to losses in the event of default by the counterparties to these derivative instruments. We manage this risk by diversifying our derivative portfolio amongst a number of financially sound counterparties. For information in relation to our marketing arrangements, see "Marketing Arrangements".

For details of material commitments to sell natural gas and crude oil which were outstanding at December 31, 2007 and March 12, 2008, see notes 11 and 13 to our 2007 Consolidated Financial Statements which is incorporated herein by reference.

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

The following table sets forth information respecting future abandonment and reclamation costs for surface leases, wells, facilities, and pipelines which are expected to be incurred by us for the periods indicated.

Period	Abandonment and Reclamation Costs Escalated at 2% Undiscounted (\$000s)	Abandonment and Reclamation Costs Escalated at 2% Discounted at 10% (\$000s)
Total liability as at December 31, 2007	540,911	80,479
Anticipated to be paid in 2008	14,870	12,540
Anticipated to be paid in 2009	15,690	12,050
Anticipated to be paid in 2010	16,000	11,170

As at December 31, 2007, we had 5,272 net wells either producing or shut-in for which we expect to incur abandonment and reclamation costs.

The future net revenues disclosed in this Annual Information Form based on the GLJ Report and the Ryder Scott Report do not contain an allowance for abandonment and reclamation costs for surface leases, facilities and pipelines. The GLJ Report and the Ryder Scott Report deducted \$98.8 million (undiscounted) and \$36.8 million (10% discount using forecast prices and costs for proved reserves) for well abandonment costs in estimating the future net revenue disclosed in this Annual Information Form.

### **Tax Horizon**

We are a taxable entity under the *Income Tax Act* (Canada) and are taxable only on income that is not distributed or distributable to our Unitholders. We distribute all of our taxable income to our Unitholders and meet the requirements of the *Income Tax Act* (Canada) applicable to us.

As a result of our tax efficient structure, annual taxable income is currently transferred from our operating entities to us and from us to Unitholders. This is primarily accomplished through the deduction by the NPI on underlying oil and gas properties and the deduction of interest on the long term notes held by our operating entities. Based on proposed changes announced by the federal government this may change. The effect of this new legislation is reflected in the after tax net revenue amounts disclosed in this Annual Information Form, other than the recently announced Provincial SIFT tax proposal. See "*Industry Conditions – Federal Tax Changes for Income Trusts and Corporations*" and "*Risk Factors – Risks to Our Revenues – Federal Tax Changes for Income Trusts and Corporations*".

We did not pay Canadian income taxes in 2007 and do not expect to pay income taxes until at least the earlier of January 1, 2011 or if and when we cease to be a trust. Our significant tax pools of approximately \$1.6 billion as at December 31, 2007 are expected to extend our cash income tax horizon beyond these dates. Commencing in January 2011, (provided that we experience only "normal growth" and no "undue expansion" before then) we may be liable for tax at the federal "net corporate income tax rate" combined with the "provincial SIFT tax factor" (effectively, the federal general corporate tax rate plus 13 percent on account of provincial corporate tax or 10 percent based on the recently announced Provincial SIFT tax proposal) on all income payable to Unitholders, which we will not be able to deduct in computing its taxable income, as a result of being characterized as a SIFT trust. See "*Risk Factors – Risks to our Revenues – Federal Tax Changes for Income Trusts and Corporations*" and "*Risk Factors – Risks Associated With Government Regulation – Changes in Legislation*".

### **Costs Incurred**

The following table summarizes the costs incurred related to our activities for the year ended December 31, 2007:

Expenditure	Year Ended December 31, 2007 (\$000s)
Property acquisition costs:	
Proved properties <sup>(1)</sup>	98,696
Unproved properties	33,211
Development costs <sup>(2)</sup>	189,130
Exploration costs <sup>(3)</sup>	44,703
Other	616
Total	366,356

Notes:

- (1) Acquisitions are net of dispositions of properties.
- (2) Development costs include development drilling costs and equipping, tie-in and facility costs for all wells.
- (3) Geological and geophysical capital expenditures and drilling costs for exploration wells drilled.

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

The following table sets forth the gross and net exploratory and development wells in which we participated during the year ended December 31, 2007:

	<b>Development</b>		<b>Exploratory</b>	
	<b>Gross</b>	<b>Net</b>	<b>Gross</b>	<b>Net</b>
Light and Medium Oil	46	24	8	3
Natural Gas	77	47	31	16
Heavy Oil	39	38	4	4
Dry	2	1	9	3
<b>Total</b>	<b>164</b>	<b>110</b>	<b>52</b>	<b>26</b>

In 2008, we are forecasting to spend between \$400 and \$420 million to expand our core regions, with approximately 60% of the amount dedicated to well-planned exploration, development and optimization of our existing assets, with the remainder of the capital targeted for the acquisition program, which has been substantially committed for 2008. The capital program contemplates the drilling of between 200 to 220 wells within our core regions. For details on the important current and likely exploration and development activities, see "*Disclosure of Reserves Data and Other Oil And Natural Gas Information – Other Oil and Natural Gas Information – Oil and Natural Gas Properties*" in this Annual Information Form.

### ***Production Estimates***

The following table sets out our gross production estimated in the GLJ Report and the Ryder Scott Report for the year ended December 31, 2008, which is reflected in the estimate of future net revenue disclosed in the forecast price tables contained under "*Disclosure of Reserves Data and Oil and Natural Gas Information*":

	<b>Light and Medium Oil (bbls/d)</b>	<b>Heavy Oil (bbls/d)</b>	<b>Natural Gas (MMcf/d)</b>	<b>Natural Gas Liquids (bbls/d)</b>	<b>BOE (Boe/d)</b>
Total Proved	9,511	8,219	159.3	5,730	50,004
Total Proved plus Probable	9,958	8,784	168.5	6,083	52,913

No individual property accounts for 5% or more of the estimated production disclosed.

### Production History and Prices Received

The following tables summarize certain information in respect of production, product prices received, royalties paid, operating expenses and resulting netback for the periods indicated below:

	Quarters Ended			
	2007			
	Dec. 31	Sept. 30	June 30	Mar. 31
<b>Average Daily Production:</b>				
Natural Gas (Mcf/d)	169,521	170,665	171,413	171,718
Light and Medium Crude Oil (bbls/d)	10,987	11,122	10,163	10,440
Heavy Oil (bbls/d)	7,951	7,971	7,096	7,161
Natural Gas Liquids (bbls/d)	5,837	5,845	5,705	5,833
Combined (boe/d)	53,029	53,382	51,533	52,054
<b>Average Price Received:</b>				
Natural Gas (\$/Mcf)	6.74	5.86	7.35	7.88
Light and Medium Crude Oil (\$/bbl)	69.57	69.31	65.16	61.78
Heavy Oil (\$/bbl)	48.99	48.03	42.09	40.79
Natural Gas Liquids (\$/bbl)	48.68	43.07	43.52	40.39
Combined (\$/boe)	58.04	56.36	52.66	50.04
<b>Royalties:</b>				
Natural Gas (\$/Mcf)	1.22	0.91	1.31	1.46
Light and Medium Crude Oil (\$/bbl)	10.86	11.08	10.14	8.99
Heavy Oil (\$/bbl)	9.03	7.72	6.47	5.48
Natural Gas Liquids (\$/bbl)	11.58	8.05	8.20	8.46
Combined (\$/boe)	8.77	7.24	8.15	8.33
<b>Production Costs:</b>				
Natural Gas (\$/Mcf)	1.16	1.17	1.21	1.15
Light and Medium Crude Oil (\$/bbl)	9.31	9.19	9.14	8.98
Heavy Oil (\$/bbl)	12.72	12.39	12.28	11.99
Natural Gas Liquids (\$/bbl)	9.31	9.19	9.14	8.98
Combined (\$/boe)	8.58	8.51	8.46	8.33
<b>Netback Received:</b>				
Natural Gas (\$/Mcf)	3.92	3.34	4.39	4.83
Light and Medium Crude Oil (\$/bbl)	48.24	47.78	44.42	42.44
Heavy Oil (\$/bbl)	24.05	24.77	20.18	20.11
Natural Gas Liquids (\$/bbl)	27.48	25.69	26.03	22.74
Combined (\$/boe)	22.71	26.27	29.93	29.69

The following table indicates our average daily production from our core regions for the year ended December 31, 2007:

	Natural Gas (Mcf/d)	Light and Medium Oil (bbls/d)	Heavy Oil (bbls/d)	NGLs (bbls/d)	BOE (boe/d)
Northeast British Columbia	44,218	599	-	2,486	10,455
Northwest Alberta	44,785	2,421	-	357	10,242
Eastern	39,775	1,335	7,548	99	15,611
Southern Alberta	42,045	6,326	-	2,863	16,197
Total	170,823	10,681	7,548	5,805	52,505

## **Marketing Arrangements**

### *Natural Gas*

We continue to maintain a risk-mitigating strategy and develop a diverse natural gas sales portfolio, which encompasses a variety of pricing mechanisms and term commitments. Our natural gas portfolio includes sales to industrial customers, distribution companies and traditional aggregators.

In addition, we have adopted a disciplined commodity hedging program. The purpose of the hedging program is to reduce volatility in the financial results, protect acquisition economics and stabilize cash flow and Unitholder's distributions against the unpredictable commodity price environment. At any given period of time, our hedging strategy is restricted to a maximum hedge position of 60% of forecasted production, net of royalties, for terms not exceeding two years and primarily utilizes costless collars. In order to control and manage credit risk and ensure competitive bids, we engage a number of reputable counterparties for our transactions.

The integration and application of these strategies resulted in an average realized price of \$6.95 per Mcf in 2007 compared to \$7.38 per Mcf in 2006. For 2008, we are forecasting our natural gas price to average \$8.76 per Mcf based on an expected average 2008 NYMEX price of US\$9.24 per MMBtu.

### *Oil and Liquids*

We sell our oil and natural gas liquids production to a variety of customers. This allows us to benefit from specific regional advantages while maintaining pricing and delivery flexibility. In 2007, our average realized oil and liquids price was \$54.40 Cdn per bbl compared to \$50.42 Cdn per bbl in 2006. Consistent with our natural gas strategy, our marketing objectives include protecting or securing minimum prices for up to 60% of our net production for terms not exceeding two years. Our crude oil hedging strategy primarily employs costless collars. Our average crude oil production quality is approximately 28° API. Our 2008 budget is based on a WTI price of \$97.15 US per bbl, which converts to approximately \$66.26 Cdn per bbl realized at the wellhead.

## **Acquisitions and Dispositions**

During 2007, we completed 10 property transactions including the acquisition and disposition of oil and natural gas properties. In aggregate, net of dispositions, we made \$98.7 million of net property acquisitions in the year. The largest of those acquisitions was \$78.3 million.

## **Environmental Policies**

We have an active program to monitor and comply with all environmental laws, rules and regulations applicable to our operations. Our policies require that all employees and contractors must report all breaches or potential breaches of environmental laws, rules and regulations to our senior management and all applicable governmental authorities. Any material breaches of environmental law, rules and regulations must be reported to our Board of Directors.

## SHARE CAPITAL OF BONAVISTA PETROLEUM

### Common Shares

Bonavista Petroleum has authorized for issuance an unlimited number of common shares, of which 50 common shares are issued and outstanding all of which we own. The voting of such shares is delegated to the Board of Directors under the Trust Indenture other than: (i) any sale, lease or other disposition of, or any interest in, all or substantially all of the assets of Bonavista Petroleum, except in conjunction with an internal reorganization of the direct or indirect assets of Bonavista Petroleum as a result of which either Bonavista Petroleum or we have the same, or substantially similar, interest, whether direct or indirect, in the assets as the interest, whether direct or indirect, that it had prior to the reorganization; (ii) any statutory amalgamation of Bonavista Petroleum with any other corporation or any amalgamation, merger or other transaction, as the case may be, of Bonavista Petroleum with any other entity, except in conjunction with an internal reorganization as referred to in paragraph (i) above; (iii) any statutory arrangement involving Bonavista Petroleum, except in conjunction with an internal reorganization as referred to in paragraph (i) above; (iv) any amendment to the articles of Bonavista Petroleum to increase or decrease the minimum or maximum number of directors; or (v) any material amendment to the articles of Bonavista Petroleum to change the authorized share capital or amend the rights, privileges, restrictions and conditions attaching to any class of Bonavista Petroleum's shares in a manner which may be prejudicial to us, which must be approved by the Unitholders by special resolution at a meeting of Unitholders called for that purpose.

The holders of common shares are entitled to receive notice of and to attend all meetings of the shareholders of Bonavista Petroleum and to one vote at such meetings. The holders of common shares will be, at the discretion of the Board of Directors and subject to applicable legal restrictions, and subject to certain preferences of holders of Exchangeable Shares, entitled to receive any dividends declared by the Board of Directors on the common shares to the exclusion of the holders of Exchangeable Shares, subject to the proviso that no dividends shall be paid on the common shares unless all declared dividends on the outstanding Exchangeable Shares have been paid in full. The holders of common shares will be entitled to share equally in any distribution of the assets of Bonavista Petroleum upon the liquidation, dissolution, bankruptcy or winding-up of Bonavista Petroleum or other distribution of its assets among its shareholders for the purpose of winding-up its affairs. Such participation is subject to the rights, privileges, restrictions and conditions attaching to the Exchangeable Shares and any other shares having priority over the common shares.

### Exchangeable Shares

Bonavista Petroleum is authorized to issue an unlimited number of Exchangeable Shares of which, as of December 31, 2007, 12,230,109 Exchangeable Shares were outstanding. The Exchangeable Shares rank prior to the common shares of Bonavista Petroleum and any other shares ranking junior to the Exchangeable Shares with respect to the payment of dividends and the distribution of assets in the event of the liquidation, dissolution or winding-up of Bonavista Petroleum. The Exchangeable Share provisions have been filed on SEDAR at [www.sedar.com](http://www.sedar.com).

Valiant Trust Company acts as the transfer agent for the Exchangeable Shares.

Each Exchangeable Share has economic rights (including the right to have the Exchange Ratio adjusted to account for distributions paid to Unitholders) and voting attributes (through the benefit of the Special Voting Rights granted to the Trustee) equivalent to those of the Trust Units into which they are exchangeable from time to time. As at December 31, 2007, the Exchange Ratio was 1.72244 and will be increased on each distribution payment date by an amount, rounded to the nearest five decimal places, equal to a fraction having as its numerator the distribution, expressed as an amount per Trust Unit, paid on that date multiplied by the Exchange Ratio immediately prior to the record date for such distribution and having as its denominator the current market price (five day weighted average trading price) on the first business day following the record date for the distribution. In addition, holders of Exchangeable Shares have the right to receive Trust Units at any time in exchange for their Exchangeable Shares, on the basis of the Exchange Ratio in effect at the time of the exchange. Fractional Trust Units will not be delivered on any exchange of Exchangeable Shares. In the event that the Exchange Ratio in effect at the time of an exchange would otherwise entitle a holder of Exchangeable Shares to a fractional Trust Unit, the number of Trust Units to be delivered will be rounded down to the nearest whole number of Trust Units. Holders of Exchangeable Shares do not

receive cash distributions from us or Bonavista Petroleum. Rather, the Exchange Ratio is adjusted to account for distributions paid to Unitholders.

### ***Ranking***

The Exchangeable Shares rank ratably with shares of any other series of exchangeable shares of Bonavista Petroleum and prior to any common shares of Bonavista Petroleum and any other shares ranking junior to the Exchangeable Shares with respect to the payment of dividends, if any, that have been declared and the distribution of assets in the event of the liquidation, dissolution or winding-up of Bonavista Petroleum.

### ***Dividends***

Holders of Exchangeable Shares will be entitled to receive cash dividends if, as and when declared by the Board of Directors. Bonavista Petroleum anticipates that it may from time to time declare dividends on the Exchangeable Shares up to but not exceeding any cash distributions on the Trust Units into which such Exchangeable Shares are exchangeable. In the event that any such dividends are paid, the Exchange Ratio will be correspondingly reduced to reflect such dividends.

### ***Certain Restrictions***

Bonavista Petroleum will not, without obtaining the approval of the holders of the Exchangeable Shares as set forth below under the subheading "*Amendment and Approval*":

- (a) pay any dividend on the common shares or any other shares ranking junior to the common shares, other than stock dividends payable in common shares or any other shares ranking junior to the Exchangeable Shares;
- (b) redeem, purchase or make any capital distribution in respect of the common shares of Bonavista Petroleum or any other shares ranking junior to the Exchangeable Shares;
- (c) redeem or purchase any other shares of Bonavista Petroleum ranking equally with the Exchangeable Shares with respect to the payment of dividends or on any liquidation distribution; or
- (d) issue any shares, other than Exchangeable Shares or common shares, which rank superior to the Exchangeable Shares with respect to the payment of dividends or on any liquidation distribution.

The above restrictions shall not apply if all declared dividends on the outstanding Exchangeable Shares shall have been paid in full.

### ***Liquidation or Insolvency of Bonavista Petroleum***

In the event of the liquidation, dissolution or winding-up of Bonavista Petroleum or any other proposed distribution of the assets of Bonavista Petroleum among its shareholders for the purpose of winding up its affairs, a holder of Exchangeable Shares, subject to applicable law, will be entitled to receive from Bonavista Petroleum, in respect of each such Exchangeable Share, that number of Trust Units equal to the Exchange Ratio as at the effective date of such event.

Upon the occurrence of such an event, we and Bonavista ExchangeCo will each have the overriding right to purchase all but not less than all of the Exchangeable Shares then outstanding (other than Exchangeable Shares which are held by us or any subsidiaries) at a purchase price per Exchangeable Share to be satisfied by the issuance or delivery, as the case may be, of that number of Trust Units equal to the Exchange Ratio at such time and, upon the exercise of this right, the holders thereof will be obligated to sell such Exchangeable Shares to us or Bonavista ExchangeCo, as applicable. This right may be exercised by either us or Bonavista ExchangeCo.

### ***Automatic Exchange Right on our Liquidation***

We have entered into a voting and exchange trust agreement which provides that in the event of a "**trust liquidation event**", as described below, we or Bonavista ExchangeCo will be deemed to have purchased all outstanding Exchangeable Shares and each holder of Exchangeable Shares will be deemed to have sold their Exchangeable Shares immediately prior to such trust liquidation event at a purchase price per Exchangeable Share to be satisfied by the issuance or delivery, as the case may be, of that number of Trust Units equal to the Exchange Ratio at such time. "**Trust liquidation event**" means:

- (a) any determination by us to institute our voluntary liquidation, dissolution or winding-up proceedings or to effect any other distribution of our assets among the Unitholders for the purpose of winding up its affairs; or
- (b) the earlier of, our receiving notice of or we otherwise becoming aware of, any threatened or instituted claim, suit, petition or other proceedings with respect to our involuntary liquidation, dissolution or winding up or to effect any other distribution of our assets among the Unitholders for the purpose of winding up our affairs in each case where we have failed to contest in good faith such proceeding within 30 days of becoming aware thereof.

### ***Retraction of Exchangeable Shares by Holders and Retraction Call Right***

Subject to the Retraction Call Right granted to us and Bonavista ExchangeCo, described below, a holder of Exchangeable Shares will be entitled at any time to require Bonavista Petroleum to redeem any or all of the Exchangeable Shares held by such holder for a retraction price (the "**Retraction Price**") per Exchangeable Share equal to the value of that number of Trust Units equal to the Exchange Ratio as at the date of redemption (the "**Retraction Date**"), to be satisfied by the delivery of such number of Trust Units. Fractional Trust Units will not be delivered. Any amount payable on account of the Retraction Price that includes a fractional Trust Unit will be rounded down to the nearest whole number of Trust Units. Holders of the Exchangeable Shares may request redemption by presenting to Bonavista Petroleum or the transfer agent for the Exchangeable Shares a certificate or certificates representing the number of Exchangeable Shares the holder desires to have redeemed, together with a duly executed retraction request and such other documents as may be reasonably required to effect the redemption of the Exchangeable Shares. Subject to extension as described below, the redemption will become effective on the Retraction Date, which will be three business days after the date on which Bonavista Petroleum or the transfer agent receives the retraction notice.

When a holder requests Bonavista Petroleum to redeem the Exchangeable Shares, we and Bonavista ExchangeCo will have an overriding right (the "**Retraction Call Right**") to purchase on the Retraction Date all but not less than all of the Exchangeable Shares that the holder has requested Bonavista Petroleum to redeem at a purchase price per Exchangeable Share equal to the Retraction Price, to be satisfied by the delivery of that number of Trust Units equal to the Exchange Ratio at such time. At the time of a Retraction Request by a holder of Exchangeable Shares, Bonavista Petroleum will immediately notify us and Bonavista ExchangeCo. We or Bonavista ExchangeCo must then advise Bonavista Petroleum within two business days as to whether the Retraction Call Right will be exercised. A holder may revoke his or her Retraction Request at any time prior to the close of business on the last business day immediately preceding the Retraction Date, in which case the holder's Exchangeable Shares will neither be purchased by us or Bonavista ExchangeCo nor be redeemed by Bonavista Petroleum. If the holder does not revoke his or her Retraction Request, the Exchangeable Shares that the holder has requested Bonavista Petroleum to redeem will on the Retraction Date be purchased by us or Bonavista ExchangeCo or redeemed by Bonavista Petroleum, as the case may be, in each case at a purchase price per Exchangeable Share equal to the Retraction Price. In addition, a holder of Exchangeable Shares may elect to instruct the Trustee to exercise the optional exchange right (the "**Optional Exchange Right**") to require us or Bonavista ExchangeCo to acquire such holder's Exchangeable Shares in circumstances where neither we nor Bonavista ExchangeCo have exercised the Retraction Call Right.

The Retraction Call Right may be exercised by either us or Bonavista ExchangeCo. If, as a result of solvency provisions of applicable law, Bonavista Petroleum is not permitted to redeem all Exchangeable Shares tendered by a retracting holder, Bonavista Petroleum will redeem only those Exchangeable Shares tendered by the holder as would not be contrary to such provisions of applicable law. The holder of any Exchangeable Shares not redeemed by

Bonavista Petroleum will be deemed to have required us to purchase such unretracted Exchangeable Shares in exchange for Trust Units on the Retraction Date pursuant to the Optional Exchange Right.

### ***Redemption of Exchangeable Shares***

Subject to applicable law and the Redemption Call Right granted to us and Bonavista ExchangeCo, Bonavista Petroleum:

- (a) will, on July 2, 2013, subject to extension of such date by the Board of Directors (the "**Automatic Redemption Date**"), redeem all but not less than all of the then outstanding Exchangeable Shares for a redemption price per Exchangeable Share equal to the value of that number of Trust Units equal to the Exchange Ratio as at the last Business day prior to that Redemption Date (as that term is defined below) (the "**Redemption Price**"), to be satisfied by the delivery of such number of Trust Units;
- (b) may, on any date that is within the first 90 days of any calendar year commencing in 2004 (the "**Annual Redemption Date**"), redeem up to that number of Exchangeable Shares equal to 40% of the Exchangeable Shares outstanding on the Effective Date for the Redemption Price per Exchangeable Share at the last Business day prior to that Redemption Date (as that term is defined below), to be satisfied by the delivery of Trust Units; and
- (c) may, at any time when the aggregate number of issued and outstanding Exchangeable Shares is less than 1 million (other than Exchangeable Shares held by us and our subsidiaries and as such shares may be adjusted from time to time) (the "**De Minimus Redemption Date**" and, collectively with the Automatic Redemption Date and Annual Redemption Date, a "**Redemption Date**"), redeem all but not less than all of the then outstanding Exchangeable Shares for the Redemption Price per Exchangeable Share (unless contested in good faith by us).

Bonavista Petroleum will, at least 90 days prior to any Redemption Date, provide the registered holders of the Exchangeable Shares with written notice of the prospective redemption of the Exchangeable Shares by Bonavista Petroleum.

We and Bonavista ExchangeCo have the right (the "**Redemption Call Right**"), notwithstanding a proposed redemption of the Exchangeable Shares by Bonavista Petroleum on the applicable Redemption Date, pursuant to the Exchangeable Share Provisions, to purchase on any Redemption Date all but not less than all of the Exchangeable Shares then outstanding (other than Exchangeable Shares held by us or our subsidiaries) in exchange for the Redemption Price per Exchangeable Share and, upon the exercise of the Redemption Call Right, the holders of all of the then outstanding Exchangeable Shares will be obliged to sell all such shares to us or Bonavista ExchangeCo, as applicable. If either we or Bonavista ExchangeCo exercises the Redemption Call Right, then Bonavista Petroleum's right to redeem the Exchangeable Shares on the applicable Redemption Date will terminate. The Redemption Call Right may be exercised by either us or Bonavista ExchangeCo.

### ***Voting Rights***

Except as required by applicable law, the holders of the Exchangeable Shares are not entitled as such to receive notice of or attend any meeting of the shareholders of Bonavista Petroleum or to vote at any such meeting. Holders of Exchangeable Shares will have the notice and voting rights respecting meetings that are provided in the Voting and Exchange Trust Agreement.

### ***Amendment and Approval***

The rights, privileges, restrictions and conditions attaching to the Exchangeable Shares may be changed only with the approval of the holders thereof. Any such approval or any other approval or consent to be given by the holders of the Exchangeable Shares will be sufficiently given if given in accordance with applicable law and subject to a minimum requirement that such approval or consent be evidenced by a resolution passed by not less than two-thirds

of the votes cast thereon (other than shares beneficially owned by us, or any of our entities and other affiliates) at a meeting of the holders of the Exchangeable Shares duly called and held at which holders of at least 10% of the then outstanding Exchangeable Shares are present in person or represented by proxy. In the event that no such quorum is present at such meeting within one-half hour after the time appointed therefor, then the meeting will be adjourned to such place and time (not less than ten days later) as may be determined at the original meeting and the holders of Exchangeable Shares present in person or represented by proxy at the adjourned meeting will constitute a quorum thereat and may transact the business for which the meeting was originally called. At the adjourned meeting, a resolution passed by the affirmative vote of not less than two-thirds of the votes cast thereon (other than shares beneficially owned by us or any of our subsidiaries and other affiliates) will constitute the approval or consent of the holders of the Exchangeable Shares.

***Actions by Us under the Support Agreement and the Voting and Exchange Trust Agreement***

Under the Exchangeable Share Provisions, Bonavista Petroleum has agreed to take all such actions and do all such things as are necessary or advisable to perform and comply with its obligations under, and to ensure the performance and compliance by us and Bonavista ExchangeCo with its obligations under, a support agreement and the voting and exchange trust agreement.

***Support Agreement and Voting and Exchange Agreement***

The support agreement and the voting and exchange trust agreement have been filed on SEDAR at [www.sedar.com](http://www.sedar.com).

**INFORMATION RELATING TO US**

**Trust Units**

An unlimited number of Trust Units may be created and issued pursuant to the Trust Indenture. The Trust Units represent equal undivided beneficial interests in the Trust. All Trust Units share equally in all distributions made by us and all Trust Units carry equal voting rights at meetings of Unitholders. No Unitholder will be liable to pay any further calls or assessments in respect of the Trust Units. No conversion, retraction, redemption or pre-emptive rights attach to the Trust Units.

The Trust Units do not represent a traditional investment and should not be viewed by investors as "shares" in us or Bonavista Petroleum. Corporate law does not govern us and the rights of Unitholders. As holders of Trust Units, Unitholders will not have the statutory rights normally associated with ownership of shares of a corporation including, for example, the right to bring "oppression" or "derivative" actions. The rights of Unitholders are specifically set forth in the Trust Indenture. In addition, trusts are not defined as recognized entities within the definitions of legislation such as the *Bankruptcy and Insolvency Act* (Canada) and the *Companies' Creditors Arrangement Act* (Canada). As a result, in the event of an insolvency or restructuring, a Unitholder's position as such may be quite different than that of a shareholder of a corporation.

The price per Trust Unit is a function of our anticipated distributable income and the ability of the Board of Directors to effect long term growth in the value of us. The market price of the Trust Units will be sensitive to a variety of market conditions including, but not limited to, interest rates, commodity prices and our ability to acquire additional assets. Changes in market conditions may adversely affect the trading price of the Trust Units.

A return on an investment in the Trust is not comparable to the return on an investment in a fixed income security. The recovery of an initial investment in us is at risk, and the anticipated return on such investment is based on many performance assumptions. Although we intend to make distributions of our available cash to holders of Trust Units, these cash distributions may be reduced or suspended. The actual amount distributed will depend on numerous factors including: the financial performance of Bonavista Petroleum, debt obligations, working capital requirements and future capital requirements. In addition, the market value of the Trust Units may decline if our cash distributions decline in the future, and that market value decline may be material.

It is important for an investor to consider the particular risk factors that may affect the industry in which it is investing, and therefore the stability of the distributions that it receives. See "*Risk Factors*".

The after tax return from an investment in Trust Units to Unitholders subject to Canadian income tax can be made up of both a return on capital and a return of capital. That composition may change over time, thus affecting an investor's after tax return. Returns on capital are generally taxed as ordinary income in the hands of a Unitholder. Returns of capital are generally tax deferred (and reduce the Unitholder's cost base in the Trust Unit for tax purposes).

### **Special Voting Units**

The Trust Indenture also provides for the issuance of special voting units and which are entitled to such number of votes at meetings of Unitholders equal to the number of Trust Units reserved for issuance that such special voting units represent, such number of votes and any other rights or limitations prescribed by the Board of Directors when the Board of Directors authorizes issuing such special voting units. The Trust Units and the special voting units vote together as a single class on all matters. In the event of any of our liquidation, dissolution or winding-up, the holders of special voting units will not be entitled to receive any of our assets available for distribution to its holders of Trust Units. The holders of special voting units will not be entitled to receive dividends or other distributions from us.

A single special voting unit was issued to Valiant Trust Company as trustee under the voting and exchange trust agreement for the benefit of holders of the Exchangeable Shares issued in connection with the Arrangement. This special voting unit is entitled to one vote for each Exchangeable Share. Valiant Trust Company is required to vote the special voting units in the manner that holders of exchangeable shares instruct, and to abstain from voting on the exchangeable shares for which Valiant Trust Company does not receive instructions.

### **Convertible Debentures**

On January 29, 2004, we issued \$100 million aggregate principal amount of 7.5% Convertible Debentures. The 7.5% Convertible Debentures, with a face value of \$1,000 per debenture, have a coupon of 7.5%, mature on June 30, 2009 and are convertible into Trust Units at a price of \$23.00 per Trust Unit. Holders converting their 7.5% Convertible Debentures will receive accrued and unpaid interest thereon. Interest on the 7.5% Convertible Debentures is paid semi-annually. The 7.5% Convertible Debentures are redeemable by us at a price of \$1,050 per 7.5% Convertible Debenture after February 1, 2007 and on or before February 1, 2008 and at a price of \$1,025 per 7.5% Convertible Debenture after February 1, 2008 and before maturity on June 30, 2009, in each case, plus accrued and unpaid interest thereon, if any.

On December 31, 2004, we closed a public offering of \$135 million aggregate principal amount of 6.75% Convertible Debentures. The 6.75% Convertible Debentures, with a face value of \$1,000 per debenture have a coupon rate of 6.75%, mature on June 30, 2010 and are convertible into Trust Units at a price of \$29.00 per Trust Unit. Holders converting their 6.75% Convertible Debentures will receive accrued and unpaid interest thereon. Interest on the 6.75% Convertible Debentures is paid semi-annually. The 6.75% Convertible Debentures are redeemable by us at a price of \$1,050 per 6.75% Convertible Debenture after December 31, 2007 and on or before December 31, 2008 and at a price of \$1,025 per 6.75% Convertible Debenture after December 31, 2008 and before maturity on June 10, 2010, in each case, plus accrued and unpaid interest thereon, if any.

For a complete description of the 7.5% Convertible Debentures and the 6.75% Convertible Debentures, reference should be made to the trust indenture creating the 7.5% Convertible Debentures and the supplemental indenture creating the 6.75% Convertible Debentures, copies of which have been filed on SEDAR at [www.sedar.com](http://www.sedar.com).

### **Trust Indenture**

The Trust Indenture, among other things, provides for the calling of meetings of Unitholders, the conduct of business thereof, notice provisions, the appointment and removal of the Trustee and the form of Trust Unit certificates. The Trust Indenture may be amended from time to time. Substantive amendments to the Trust

Indenture, including early termination of the Trust and the sale or transfer of our property as an entirety or substantially as an entirety requires approval by special resolution of the Unitholders. Any approval or consent of Unitholders in relation to any matter required by any regulatory body will require a majority of, or such other level of approval of Unitholders as may be stipulated by such regulatory authority, including as to the exclusion of interested or other Unitholders in the calculation of such level of approval. See "*Information Relating to Us – Meetings and Voting*" below.

The following is a summary of certain provisions of the Trust Indenture. For a complete description of such indenture, reference should be made to the Trust Indenture, a copy of which has been filed on SEDAR at [www.sedar.com](http://www.sedar.com).

### ***Trustee***

Valiant Trust Company is our trustee and also acts as the transfer agent for the Trust Units. The Trustee is responsible for, among other things, accepting subscriptions for Trust Units and issuing Trust Units pursuant thereto and maintaining our books and records and providing timely reports to holders of Trust Units. The Trust Indenture provides that the Trustee shall exercise its powers and carry out its functions thereunder as Trustee honestly, in good faith and in our best interests and in the best interest of the Unitholders and, in connection therewith, shall exercise that degree of care, diligence and skill that a reasonably prudent trustee would exercise in comparable circumstances.

The initial term of the Trustee's appointment is until the third annual meeting of Unitholders. The Unitholders shall, at the third annual meeting of the Unitholders, re-appoint, or appoint a successor to the Trustee for an additional three year term, and thereafter, the Unitholders are required to reappoint or appoint a successor to the Trustee at the annual meeting of Unitholders three years following the reappointment or appointment of the successor to the Trustee. The Trustee may also be removed by special resolution of the Unitholders. Such resignation or removal becomes effective upon the acceptance or appointment of a successor trustee.

Bonavista Petroleum presently administers us on behalf of the Trustee. Bonavista Petroleum, on behalf of the Trustee, keeps such books and records as are necessary for the proper recording of our business transactions.

The Trust Indenture provides that the Trustee shall be under no liability for any action or failure to act unless such liabilities arise out of the Trustee's gross negligence, wilful default or fraud. The Trustee, where it has met its standard of care, shall be indemnified out of our assets for any taxes or other government charges imposed upon the Trustee in consequence of its performance of its duties but shall have no additional recourse against Unitholders. In addition, the Trust Indenture contains other customary provisions limiting the liability of the Trustee.

### ***Future Offerings***

The Trust Indenture provides that Trust Units, including rights, warrants and other securities to purchase, to convert into or to exchange into Trust Units, may be created, issued, sold and delivered on such terms and conditions and at such times as the Trustee, upon the recommendation of the Board of Directors may determine. The Trust Indenture also provides that Bonavista Petroleum may authorize the creation and issuance of debentures, notes and other evidences of indebtedness by us which debentures, notes or other evidences of indebtedness may be created and issued from time to time on such terms and conditions to such persons and for such consideration as Bonavista Petroleum may determine.

### ***Meetings and Voting***

Annual meetings of the Unitholders will be held annually. Special meetings of Unitholders may be called at any time by the Trustee and shall be called by the Trustee upon the written request of Unitholders holding in aggregate not less than 20% of the Trust Units. Notice of all meetings of Unitholders shall be given to Unitholders at least 21 days prior to the meeting.

Unitholders will be entitled at each annual meeting to appoint our auditors and to elect all the members of the Board of Directors.

### ***Our Management***

The Board of Directors has generally been delegated all of our significant management decisions. In particular, the Trustee has delegated to Bonavista Petroleum responsibility for any and all matters relating to the following: (i) an offering; (ii) ensuring compliance with all applicable laws, including in relation to an offering; (iii) all matters relating to the content of any offering documents, the accuracy of the disclosure contained therein, and the certification thereof; (iv) all matters concerning the terms of, and amendment from time to time of our material contracts; (v) all matters concerning any underwriting or agency agreement providing for the sale of Trust Units or rights to Trust Units; (vi) all matters relating to the redemption of Trust Units; (vii) all matters relating to the voting rights on any investments in the trust fund or any subsequent investments; and (viii) all matters relating to the specific powers and authorities as set forth in the Trust Indenture.

Bonavista Petroleum has accepted all such delegation and has agreed that, in respect of such matters, it shall carry out its functions honestly, in good faith and in our best interests and the best interests of the Unitholders and, in connection therewith, shall exercise that degree of care, diligence and skill that a reasonable person would exercise in comparable circumstances.

### ***Limitation on Non-Resident Ownership***

In order that we maintain our status as a "mutual fund trust" under the *Income Tax Act* (Canada), certain provisions of the *Income Tax Act* (Canada) require that we not be established nor maintained primarily for the benefit of non-residents of Canada ("**non-residents**"). Accordingly, in order to comply with such provisions, the Trust Indenture contains restrictions on the ownership of Trust Units by Unitholders who are non-residents. In this regard, we shall, among other things, take all necessary steps to monitor the ownership of the Trust Units to carry out such intentions. If at any time we become aware that the beneficial owners of 50% or more of the Trust Units then outstanding are or may be non-residents or that such a situation is imminent, we shall take such action as may be necessary to carry out the forgoing intentions.

### ***Right of Redemption***

Trust Units are redeemable at any time on demand by the holders thereof upon delivery to us of the certificate or certificates representing such Trust Units, accompanied by a duly completed and properly executed notice requiring redemption. Upon receipt of the notice to redeem Trust Units by us, the holder thereof shall only be entitled to receive a price per Trust Unit (the "**Market Redemption Price**") equal to the lesser of: (i) 90% of the "**market price**" of the Trust Units on the principal market on which the Trust Units are quoted for trading during the 10 trading day period commencing immediately after the date on which the Trust Units are tendered to us for redemption; and (ii) the closing market price on the principal market on which the Trust Units are quoted for trading on the date that the Trust Units are so tendered for redemption.

For the purposes of this calculation, "**market price**" will be an amount equal to the simple average of the closing price of the Trust Units for each of the trading days on which there was a closing price; provided that, if the applicable exchange or market does not provide a closing price but only provides the highest and lowest prices of the Trust Units traded on a particular day, the market price shall be an amount equal to the simple average of the average of the highest and lowest prices for each of the trading days on which there was a trade; and provided further that if there was trading on the applicable exchange or market for fewer than five of the 10 trading days, the market price shall be the simple average of the following prices established for each of the 10 trading days: (i) the average of the last bid and last ask prices for each day on which there was no trading; (ii) the closing price of the Trust Units for each day that there was trading if the exchange or market provides a closing price; and (iii) the average of the highest and lowest prices of the Trust Units for each day that there was trading, if the market provides only the highest and lowest prices of Trust Units traded on a particular day. The closing market price shall be: an amount equal to the closing price of the Trust Units if there was a trade on the date; an amount equal to the average of the highest and lowest prices of the Trust Units if there was trading and the exchange or other market provides

only the highest and lowest prices of Trust Units traded on a particular day; and the average of the last bid and last ask prices if there was no trading on the date.

The aggregate Market Redemption Price payable by us in respect of any Trust Units surrendered for redemption during any calendar month shall be satisfied by way of a cash payment on the last day of the following month. The entitlement of Unitholders to receive cash upon the redemption of their Trust Units is subject to the limitation that the total amount payable by us in respect of such Trust Units and all other Trust Units tendered for redemption in the same calendar month and in any preceding calendar month during the same year shall not exceed \$250,000; provided that we may, in our sole discretion, waive such limitation in respect of any calendar month. If this limitation is not so waived, the Market Redemption Price payable by us in respect of Trust Units tendered for redemption in such calendar month shall be paid on the last day of the following month as follows: (i) firstly, by us distributing Notes having an aggregate principal amount equal to the aggregate Market Redemption Price of the Trust Units tendered for redemption; and (ii) secondly, to the extent that we do not hold Notes having a sufficient principal amount outstanding to effect such payment, by us issuing our own promissory notes to the Unitholders who exercised the right of redemption having an aggregate principal amount equal to any such shortfall, which promissory notes, (herein referred to as "**Redemption Notes**") shall have terms and conditions substantially identical to those of the Notes.

If at the time Trust Units are tendered for redemption by a Trust Unitholder, the outstanding Trust Units are not listed for trading on the Toronto Stock Exchange and are not traded or quoted on any other stock exchange or market which Bonavista Petroleum considers, in its sole discretion, provides representative fair market value price for the Trust Units or trading of the outstanding Trust Units is suspended or halted on any stock exchange on which the Trust Units are listed for trading or, if not so listed, on any market on which the Trust Units are quoted for trading, on the date such Trust Units are tendered for redemption or for more than five trading days during the 10 trading day period, commencing immediately after the date such Trust Units were tendered for redemption then such Trust Unitholder shall, instead of the Market Redemption Price, be entitled to receive a price per Trust Unit (the "**Appraised Redemption Price**") equal to 90% of the fair market value thereof as determined by Bonavista Petroleum as at the date on which such Trust Units were tendered for redemption. The aggregate Appraised Redemption Price payable by us in respect of Trust Units tendered for redemption in any calendar month shall be paid on the last day of the third following month by, at our option: (i) a cash payment; or (ii) a distribution of Notes and/or Redemption Notes as described above.

It is anticipated that this redemption right will not be the primary mechanism for holders of Trust Units to dispose of their Trust Units. Notes or Redemption Notes which may be distributed in specie to Unitholders in connection with a redemption will not be listed on any stock exchange and no market is expected to develop in such Notes or Redemption Notes. Notes or Redemption Notes may not be qualified investments for trusts governed by registered retirement savings plans, registered retirement income funds, deferred profit sharing plans and registered education savings plans.

### ***Termination of the Trust***

The Unitholders may vote to terminate the Trust at any meeting of the Unitholders, subject to the following: (a) a vote may only be held if requested in writing by the holders of not less than 20% of the Trust Units; (b) a quorum of 50% of the issued and outstanding Trust Units is present in person or by proxy; and (c) the termination must be approved by special resolution of the Unitholders.

Unless the Trust is earlier terminated or extended by vote of the Unitholders, the Trustee shall commence to wind-up the affairs of the Trust on December 31, 2099. In the event that the Trust is wound-up, the Trustee will liquidate all our assets, pay, retire, discharge or make provision for some or all of our obligations and then distribute the remaining proceeds of sale to Unitholders.

### ***Reporting to Unitholders***

Our financial statements will be audited annually by an independent recognized firm of chartered accountants. Our audited financial statements, together with the report of such chartered accountants, will be mailed by the Trustee to Unitholders and the unaudited interim financial statements will be mailed to Unitholders within the periods

prescribed by securities legislation. Our year end is December 31. We are also subject to the continuous disclosure obligations under all applicable securities legislation.

Unitholders are entitled to inspect, during normal business hours, at the offices of the Trustee, and, upon payment of reasonable reproduction costs, to receive photocopies of the Trust Indenture and a listing of the registered holders of Trust Units.

## **CORPORATE GOVERNANCE**

### **General**

In general, Bonavista Petroleum has been delegated substantially all of our management decisions. The Unitholders are entitled to elect all of the Board of Directors pursuant to the terms of the Trust Indenture. The Articles of Bonavista Petroleum provides that the Board of Directors shall consist of a minimum of three and a maximum of eleven directors.

### **Trust Indenture**

Pursuant to the Trust Indenture, Unitholders are entitled to direct the manner in which we will vote our common shares in Bonavista Petroleum at all meetings in respect of matters, relating to the election of the directors of Bonavista Petroleum, approving its financial statements and appointing auditors of Bonavista Petroleum who shall be the same as our auditors. Prior to us voting our common shares in Bonavista Petroleum, in respect of such matters, each Unitholder is entitled to vote in respect of the matter on the basis of one vote per Trust Unit held, and we are required to vote our common shares in Bonavista Petroleum in accordance with the result of the vote of Unitholders.

### **Decision Making**

The Board of Directors has a mandate to supervise the management of our business and affairs, Bonavista Petroleum and our other direct or indirect subsidiaries, partnerships and trusts and to act with a view to our best interest. The Board of Directors' mandate includes: (a) the responsibility for managing its own affairs; (b) monitoring of management and our activities; (c) reviewing strategic operating, capital and financial plans; and (d) compliance reporting and corporate communications. In particular, significant operational decisions and all decisions relating to: (i) the acquisition and disposition of properties for a purchase price or proceeds in excess of \$20 million; (ii) the approval of capital expenditure budgets; and (iii) establishment of credit facilities are made by the Board of Directors. In addition, the Trustee has delegated broad discretion in relation to the day to day operations of the Trust to the Board of Directors including all decisions relating to: (i) matters relating to any offers for Trust Units; (ii) issuances of additional Trust Units; and (iii) the determination of the distribution policy. The Board of Directors holds regularly scheduled meetings at least quarterly to review the business and affairs of our subsidiaries, partnerships and trusts and make any necessary decisions relating thereto.

The Trust Indenture gives to the Board of Directors the authority to exercise the rights, powers and privileges for all matters relating to the maximization of Unitholder value in the context of an Offer including any Unitholder rights protection plan, any defensive action to an Offer, any Directors Circular in response to an Offer, any regulatory or court proceeding relating to an Offer and any related or ancillary matter.

### **Distributions and Distribution Policy**

Cash distributions are made on the 15<sup>th</sup> day (or if such date is not a business day, on the next business day) following the end of each calendar month to Unitholders of record on the last business day of each such calendar month or such other date as determined from time to time by the Trustee.

The Board of Directors, on our behalf, reviews the distribution policy from time to time. The current distribution policy incorporates the withholding of approximately 40% to 50% of cash flow generated for the financing of capital expenditures in order to provide sustainable distributions in the long-term. These capital expenditures would

include exploration optimization and development expenditures along with tuck-in property acquisitions in our core regions, but excluding major acquisitions. Major acquisitions are treated by Bonavista as incremental to the base business plan and therefore will translate into growth to our Unitholders. Our distribution policy also includes spending approximately \$15 million per annum as part of the capital expenditure program to fund reclamation expenditures incurred during the year. The actual amount spent is dependent on the reclamation obligations that arise during the year.

Distributions are normally announced on a quarterly basis in the context of prevailing and anticipated commodity prices. During periods of volatile commodity prices, we may vary the distribution rate monthly.

### Directors and Officers

The name, municipality of residence, position and principal occupation for the prior five years, of each of the directors and officers of Bonavista Petroleum are as follows:

<b>Name and Municipality of Residence</b>	<b>Position with Bonavista Petroleum</b>	<b>Principal Occupation</b>
<b>Keith A. MacPhail</b> <sup>(2)</sup> Calgary, Alberta	Chairman, President, Chief Executive Officer and Director	Chairman, President and Chief Executive Officer of Bonavista Petroleum.
<b>Ronald J. Poelzer</b> <sup>(3)</sup> Calgary, Alberta	Executive Vice President, Chief Financial Officer and Director	Executive Vice President and Chief Financial Officer of Bonavista Petroleum.
<b>Ian S. Brown</b> <sup>(1)(3)(7)</sup> Calgary, Alberta	Director	Independent Businessman.
<b>Michael M. Kanovsky</b> <sup>(1)(2)(4)(5)</sup> Victoria, British Columbia	Director	President, Sky Energy Corporation (an energy investment corporation).
<b>Harry L. Knutson</b> <sup>(3)(4)</sup> Vancouver, British Columbia	Director	Chairman and Chief Executive Officer, Nova Bancorp. Group (investment advisors and merchant bankers).
<b>Margaret A. McKenzie</b> <sup>(1)(3)(7)</sup> Calgary, Alberta	Director	CFO of Range Royalty Management Ltd. (general partner of Range Royalty Limited Partnership, a private royalty partnership) and CFO of Spur Resources Ltd. (a private oil and natural gas exploration and development company).
<b>Christopher P. Slubicki</b> <sup>(2)(4)(7)</sup> Calgary, Alberta	Director	Independent Businessman.
<b>Walter C. Yeates</b> <sup>(1)(2)</sup> Toronto, Ontario	Director	Independent Businessman.
<b>Glenn A. Hamilton</b> <sup>(7)</sup> Calgary, Alberta	Senior Vice President	Senior Vice President of Bonavista Petroleum
<b>John A. Curkan</b> Calgary, Alberta	Vice President, Marketing	Vice President, Marketing of Bonavista Petroleum.
<b>Orest G. Humeniuk</b> Calgary, Alberta	Vice President, Land	Vice President, Land of Bonavista Petroleum.
<b>Dean M. Kobelka</b> Calgary, Alberta	Vice President and Controller	Vice President and Controller of Bonavista Petroleum.
<b>Thomas J. Mullane</b> Calgary, Alberta	Vice President, Engineering	Vice President, Engineering of Bonavista Petroleum.
<b>Lynda J. Robinson</b> <sup>(7)</sup> Calgary, Alberta	Vice President, Human Resources and Administration	Vice President, Human Resources and Administration of Bonavista Petroleum.
<b>Jason E. Shehar</b> Calgary, Alberta	Vice President, Production	Vice President, Production of Bonavista Petroleum.

<b>Name and Municipality of Residence</b>	<b>Position with Bonavista Petroleum</b>	<b>Principal Occupation</b>
<b>Hank R. Spence</b> Calgary, Alberta	Vice President, Operations	Vice President, Operations of Bonavista Petroleum.
<b>Johannes H. Thiessen</b> Calgary, Alberta	Vice President, Exploration	Vice President, Exploration of Bonavista Petroleum.
<b>Grant A. Zawalsky</b> Calgary, Alberta	Corporate Secretary	Partner, Burnet, Duckworth & Palmer LLP (barristers and solicitors).

Notes:

- (1) Member of audit committee.
- (2) Member of reserves committee.
- (3) Member of governance and nominating committee.
- (4) Member of compensation committee.
- (5) Lead director of Bonavista Petroleum.
- (6) Bonavista Petroleum does not have an executive committee.
- (7) Each of our directors and officers have held the positions set forth above or other positions in Bonavista Petroleum for the previous five years other than: (i) Ian S. Brown who was a Senior Managing Director of Raymond James Ltd. from 1995 to 2005; (ii) Margaret A. McKenzie who was Vice President, Finance and Chief Financial Officer of Profico Energy Management Ltd. from 2001 to 2006; (iii) Christopher P. Slubicki who was Vice Chairman of Scotia Waterous from July, 2005 to June, 2006. Prior thereto, managing director of Waterous & Co; (iv) Glenn A. Hamilton who was Vice President and Chief Financial Officer of NuVista Energy Ltd. since July 2, 2003, prior to joining us on July 1, 2006, and prior thereto was Vice President, Finance of Bonavista Petroleum; and (v) Lynda J. Robinson who was Manager of Corporate Services of StarPoint Energy Trust prior to joining us in January of 2006, prior thereto Ms. Robinson was Supervisor of Corporate Services of Bonavista Petroleum.

As at March 17, 2008, the directors and officers of Bonavista Petroleum, as a group, as a group, beneficially owned, or controlled or directed, directly or indirectly, 2,880,188 Trust Units or approximately 3% of the issued and outstanding Trust Units and 9,971,027 Exchangeable Shares or approximately 82% of the issued and outstanding Exchangeable Shares resulting in an approximate total average ownership of 19%.

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

No director or executive officer of Bonavista Petroleum (nor any personal holding company of any of such persons) is, as of the date of this Annual Information Form, or was within ten years before the date of this Annual Information Form, a director, chief executive officer or chief financial officer of any company (including Bonavista Petroleum), that was subject to a cease trade order (including a management 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, in each case that was in effect for a period of more than 30 consecutive days (collectively, 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 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.

Except as otherwise disclosed herein, no director or executive officer of Bonavista Petroleum (nor any personal holding company of any of such persons), or shareholder holding a sufficient number of securities of Bonavista to affect materially the control of Bonavista is, as of the date of this Annual Information Form, or has been within the ten years before the date of this Annual Information Form, a director or executive officer of any company (including Bonavista Petroleum) that, while that person was acting in that capacity, or within a year of that person ceasing to act in that capacity, became 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 has, within the ten years before the date of this Annual Information Form, 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, other than Mr. Zawalsky who was a director of Efficient Energy Resources Ltd. (a private electrical generation company) which agreed to the voluntary appointment of a receiver in 2005.

No director or executive officer of Bonavista Petroleum (nor any personal holding company of any of such persons), or shareholder holding a sufficient number of securities of Bonavista to affect materially the control of Bonavista, has been subject to 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 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**

Circumstances may arise where members of the Board of Directors serve as directors or officers of corporations which are in competition to our interests and the interests of Bonavista Petroleum. No assurances can be given that opportunities identified by such board members will be provided to us or Bonavista Petroleum.

The *Business Corporations Act* (Alberta) provides that in the event that a director has an interest in a contract or proposed contract or agreement, the director shall disclose his interest in such contract or agreement and shall refrain from voting on any matter in respect of such contract or agreement unless otherwise provided under such Act. To the extent that conflicts of interest arise, such conflicts will be resolved in accordance with the provisions of such Act.

## **AUDIT COMMITTEE INFORMATION**

### **Audit Committee Mandate and Terms of Reference**

The Mandate and Terms of Reference of the Audit Committee of the Board of Directors is attached hereto as Appendix D.

### **Composition of the Audit Committee**

The members of our Audit Committee are Mr. Ian Brown, Mr. Michael Kanovsky, Ms. Margaret McKenzie and Mr. Walter Yeates, each of whom are independent and financially literate. We have adopted the definition of "independence" as set out in Section 1.4 of Multilateral Instrument 52-110 Audit Committees. The relevant education and experience of each Audit Committee member is outlined below:

#### *Ian Brown:*

Mr. Brown is a Chartered Accountant with extensive director, financial and capital markets experience. From 1995 - 2005 Mr. Brown was a Senior Managing Director of Raymond James Ltd. (formerly Goepel McDermid). Prior thereto Mr. Brown was the Executive Vice President of the Alberta Stock Exchange from 1986 - 1995. Prior thereto, Mr. Brown was in the practice of public accounting.

Mr. Brown joined the Board of Directors in May 2004.

Mr. Brown also sits on the following boards: the Canadian Investor Protection Fund, Petrobank Energy and Resources Ltd., Rising Sky Energy Ltd., and Stem Cell Therapeutics Corp. In addition Mr. Brown was on the board of Market Regulation Services Inc. from 2001 until 2005.

Mr. Brown holds a Bachelor of Commerce degree from the University of Windsor and a Bachelor of Arts degree from McMaster University. Mr. Brown obtained his Chartered Accountants designation in 1983.

#### *Michael Kanovsky:*

Mr. Kanovsky has had significant experience in the oil and natural gas sector. In 1978, he co-founded Canadian Northstar Corporation and its successor, Northstar Energy Corporation, where he was primarily responsible for strategic development, finance and acquisitions until it was taken over by Devon Energy Corporation. Mr. Kanovsky continues today as a Director of Devon Energy. Mr. Kanovsky has also held positions such as

Chairman of Taro Industries Limited, CEO of Arrowstar Drilling and Vice-Chairman of Precision Drilling Inc. In 1997, Mr. Kanovsky was instrumental in the reorganization of Bonavista Petroleum and continues as an active director. He is also a director of ARC Energy Trust, Accrete Energy Inc., Transalta Inc. and Pure Technologies.

Mr. Kanovsky joined the Board of Directors in November 1997.

Mr. Kanovsky holds a Bachelor of Applied Science with Honours degree in Mechanical Engineering from Queen's University and a Masters of Business Administration from the University of Western Ontario's Ivey School of Business.

*Margaret A. McKenzie:*

Margaret McKenzie is a Chartered Accountant with several years experience in the oil and natural gas industry. Ms. McKenzie is currently the Chief Financial Officer of Range Royalty Limited Partnership and Spur Resources Ltd. She was previously Vice President Finance and Chief Financial Officer of Profico Energy Management Ltd. and Manager Treasury and Administration with Renaissance Energy Ltd. Ms. McKenzie joined the board of directors in May 2006.

Ms. McKenzie also sits on the board of directors of Zargon Oil & Gas Ltd., a subsidiary of Zargon Energy Trust, and is a member of Zargon's Audit Committee.

Ms. McKenzie holds a Bachelor of Commerce with Distinction degree from the University of Saskatchewan and is a member of the Institute of Chartered Accountants of Alberta since 1985.

*Walter Yeates:*

Mr. Yeates was a Director of UBS Warburg, investment banker, and was active in corporate finance, valuations and advisory services for several years. Prior to this, Mr. Yeates was a financial officer of Alberta Energy Company and Bow Valley Resource Services in Calgary, and Canada Development Corp., a large management holding company in Toronto. Mr. Yeates was a founding partner of a successful international inter-bank currency broker headquartered in New York City and was also on various private and public advisory boards.

Mr. Yeates joined the Board of Directors in July 2003.

Mr. Yeates holds an MBA degree from the University of Western Ontario's Ivey School of Business.

### **Pre-Approval of Policies and Procedures**

The Audit Committee must pre-approve all non-audit services to be provided to us and our subsidiary entities by the external auditors. The Audit Committee may delegate to one or more members the authority to pre-approve non-audit services, provided that the member report to the Audit Committee at the next scheduled meeting such pre-approval and the member comply with such other procedures as may be established by the Audit Committee from time to time.

### **External Auditor Service Fees**

#### ***Audit Fees***

The aggregate fees billed by Bonavista Petroleum's external auditor in each of the last two fiscal years for audit services were \$220,000 in 2007 and \$200,000 in 2006.

**Audit-Related Fees**

The aggregate fees billed in each of the last two fiscal years for assurance related services by Bonavista Petroleum's external auditor that are reasonably related to the performance of the audit or review of Bonavista Petroleum's financial statements that are not reported under "Audit Fees" above were \$57,000 in 2007 and \$53,000 in 2006.

**Tax Fees**

The aggregate fees billed in each of the last two fiscal years for professional services rendered by Bonavista Petroleum's external auditor for tax compliance, tax advice and tax planning were \$10,865 in 2007 and \$13,480 in 2006.

**All Other Fees**

The aggregate fees billed in each of the last two fiscal years for products and services provided by Bonavista Petroleum's auditors other than services reported above were \$nil in 2007 and \$nil in 2006.

**DISTRIBUTIONS TO UNITHOLDERS**

The following monthly cash distributions were declared in 2007 in the following amounts:

<u>For the Month Ended</u>	<u>Distributions per Unit</u>	<u>Payment Date</u>
January 31, 2007	\$0.30	February 15, 2007
February 28, 2007	\$0.30	March 15, 2007
March 31, 2007	\$0.30	April 16, 2007
April 30, 2007	\$0.30	May 15, 2007
May 31, 2007	\$0.30	June 15, 2007
June 30, 2007	\$0.30	July 16, 2007
July 31, 2007	\$0.30	August 15, 2007
August 31, 2007	\$0.30	September 17, 2007
September 30, 2007	\$0.30	October 15, 2007
October 31, 2007	\$0.30	November 15, 2007
November 30, 2007	\$0.30	December 17, 2007
December 31, 2007	\$0.30	January 15, 2008
<b>Total</b>	<u>\$3.60</u>	

For Canadian income tax purposes, cash distributions paid to Unitholders in 2007 were 100% taxable as other income.

### MARKET FOR SECURITIES

The Trust Units, 7.5% Convertible Debentures and 6.5% Convertible Debentures are listed and traded on the Toronto Stock Exchange. The trading symbol for the Trust Units is BNP.UN, and for the 7.5% Convertible Debentures is BNP.DB and for 6.75% Convertible Debentures is BNP.DB.A. The Exchangeable Shares and Exchangeable Partnership Units are not listed on any stock exchange.

The following sets forth trading information for the Trust Units in 2007 and 2008 up to March 17, 2008.

<u>Period</u>	<u>High</u>	<u>Low</u>	<u>Volume</u>
<b><u>2007</u></b>			
January.....	\$29.35	\$25.90	6,104,225
February.....	\$29.93	\$28.70	4,131,536
March.....	\$31.89	\$28.26	4,063,308
April.....	\$32.09	\$29.12	5,000,366
May.....	\$33.54	\$31.00	4,376,155
June.....	\$32.44	\$30.10	4,274,050
July.....	\$31.38	\$28.94	2,956,191
August.....	\$30.40	\$27.37	3,612,268
September.....	\$29.52	\$27.25	4,452,170
October.....	\$31.85	\$28.80	4,374,991
November.....	\$31.53	\$24.14	8,163,062
December.....	\$28.68	\$25.27	4,843,120
<b><u>2008</u></b>			
January.....	\$29.49	\$24.24	3,906,854
February.....	\$31.35	\$26.55	4,919,730
March (1 to 17).....	\$30.49	\$28.73	3,087,247

The following sets forth trading information for the 7.5% Convertible Debentures in 2007 and 2008 up to March 17, 2008.

<u>Period</u>	<u>High</u>	<u>Low</u>	<u>Volume</u>
<b><u>2007</u></b>			
January.....	\$115.99	\$111.01	420
February.....	\$129.50	\$119.54	2,320
March.....	\$135.90	\$114.02	3,040
April.....	\$138.75	\$125.00	1,000
May.....	\$145.00	\$131.70	1,340
June.....	\$135.00	\$131.26	1,540
July.....	\$135.00	\$130.04	480
August.....	\$127.65	\$122.53	620
September.....	\$127.19	\$126.00	1,250
October.....	\$135.65	\$125.00	3,010
November.....	\$129.05	\$123.00	980
December.....	\$123.00	\$113.10	780
<b><u>2008</u></b>			
January.....	\$126.00	\$113.22	1,200
February.....	\$135.00	\$123.68	900
March (1 to 17).....	(No trades in this period)		-

The following sets forth trading information for the 6.75% Convertible Debentures in 2007 and 2008 up to March 17, 2008.

<u>Period</u>	<u>High</u>	<u>Low</u>	<u>Volume</u>
<b><u>2007</u></b>			
January.....	\$108.00	\$104.26	19,270
February.....	\$111.50	\$108.50	4,900
March.....	\$110.00	\$106.10	9,250
April.....	\$111.13	\$107.00	13,880
May.....	\$115.50	\$107.04	14,650
June.....	\$110.25	\$107.00	9,710
July.....	\$109.25	\$105.12	4,510
August.....	\$106.48	\$102.52	5,880
September.....	\$105.00	\$102.00	5,910
October.....	\$109.75	\$103.02	4,790
November.....	\$107.04	\$98.52	11,020
December.....	\$101.00	\$97.98	40,770
<b><u>2008</u></b>			
January.....	\$103.75	\$100.25	5,050
February.....	\$108.00	\$101.00	5,160
March (1 to 17).....	\$106.00	\$103.77	2,120

## INDUSTRY CONDITIONS

### General

The oil and natural gas industry is subject to extensive controls and regulations governing its operations (including land tenure, exploration, development, production, refining, transportation and marketing) imposed by legislation enacted by various levels of government and with respect to pricing and taxation of oil and natural gas by 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 controls or regulations will affect our operations in a manner materially different than they would affect other oil and gas companies of similar size. All current legislation is a matter of public record and we are 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 and Natural Gas

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 the markets, the value of refined products, the supply/demand balance and other contractual terms. 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 ("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 licence requires the approval of the Governor in Council.

The price of natural gas is determined by 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 a larger quantity requires an exporter to obtain an export licence from the NEB and the issuance of such licence requires 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**

Although pipeline expansions are ongoing, the lack of firm pipeline capacity may affect the oil and natural gas industry and may limit the ability to produce and to market natural gas production. In addition, the pro-rationing of capacity on the inter-provincial pipeline systems also continues to affect the ability to export oil and natural gas.

### **The North American Free Trade Agreement**

The North American Free Trade Agreement ("NAFTA") among the governments of Canada, United States of America 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 domestic use (based upon 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 voluntary measures which only restrict the volume of exports; and (iii) disrupt normal channels of supply. All three countries are prohibited from imposing minimum or maximum export or import price requirements, provided, in the case of export price requirements, prohibition in any circumstances in which any other form of quantitative restriction is prohibited, and in the case of import price requirements, such requirements do not apply with respect to enforcement of countervailing and anti-dumping orders and undertakings.

NAFTA contemplates the reduction of Mexican restrictive trade practices in the energy sector by 2010 and prohibits discriminatory border restrictions and export taxes. NAFTA also contemplates clearer disciplines on regulators to ensure fair implementation of any regulatory changes and to minimize disruption of contractual arrangements and avoid undue interference with pricing, marketing and distribution arrangements, which is important for Canadian natural gas exports.

### **Provincial Royalties and Incentives**

#### ***General***

In addition to federal regulation, each province has legislation and regulations which govern land tenure, royalties, production rates, environmental protection, and other matters. The royalty regime 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 negotiations between the mineral owner and the lessee, although production from such lands is subject to certain provincial taxes and royalties. Crown royalties are determined by governmental regulation and are generally calculated as a percentage of the value of the 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, and tax credits, and are generally introduced when commodity prices are low. The programs are designed to encourage exploration and development activity by improving earnings and cash flow within the industry. Royalty holidays and reductions

would reduce the amount of Crown royalties paid by oil and gas producers to the provincial governments and would increase the net income and funds from operations of such producers. However, the trend in recent years has been for provincial governments to eliminate, amend or allow such incentive programs to expire without renewal, and consequently few such incentive programs are currently operative.

The Canadian federal corporate income tax rate levied on taxable income is 22.1% effective January 1, 2007 for active business income including resource income. With the elimination of the corporate surtax effective January 1, 2008 and other rate reductions introduced in the October 2007 Economic Statement and Notice of Ways and Means Motion, 2006 Federal Budget, the federal corporate income tax rate will decrease to 15% in five steps: 19.5% on January 1, 2008, 19% on January 1, 2009; 18% on January 1, 2010, 16.5% on January 1, 2011 and 15% on January 2012.

### **Alberta**

In Alberta, companies are granted the right to explore, produce and develop petroleum and natural gas resources in exchange for royalties, bonus bid payments and rents. Currently, the amount of royalties that are payable is influenced by the oil production, density of the oil, and the vintage of the oil. Originally, the vintage classified oil as "new oil" and "old oil" depending on when the oil pools were discovered. If the pool was discovered prior to March 31, 1974 it is considered "old oil", if it was discovered after March 31, 1974 and before September 1, 1992, it is considered "new oil". The Alberta government introduced in 1992 a Third Tier Royalty with a base rate of 10% and a rate cap of 25% for oil pools discovered after September 1, 1992. The new oil royalty reserved to the Crown has a base rate of 10% and a rate cap of 30%. The old oil royalty reserved to the Crown has a base rate of 10% and a rate cap of 35%.

The royalty reserved to the Crown in respect of natural gas production, subject to various incentives, is between 15% and 30%, in the case of new natural gas, and between 15% and 35%, in the case of old natural gas, depending upon a prescribed or corporate average reference price. Natural gas produced from qualifying intervals in eligible gas wells spudded or deepened to a depth below 2,500 metres is also subject to a royalty exemption, the amount of which depends on the depth of the well.

Oil sands projects are subject to a specific regulation made effective July 1, 1997, and expiring June 30, 2009, which, among other things, determines the Crown's share of crude and processed oil sands products.

Regulations made pursuant to the *Mines and Minerals Act* (Alberta) provided various incentives for exploring and developing oil reserves in Alberta. However, the Alberta Government announced in August of 2006 that four royalty programs were to be amended, a new program was to be introduced and the Alberta Royalty Tax Credit Program ("**ARTC**") was to be eliminated, effective January 1, 2007. The programs affected by this announcement are: (i) Deep Gas Royalty Holiday; (ii) Low Productivity Well Royalty Reduction; (iii) Reactivated Well Royalty Exemption; and (iv) Horizontal Re Entry Royalty Reduction. The program being introduced is the Innovative Energy Technologies Program (the "**IETP**") which is intended to promote the producers' investment in research, technology and innovation for the purposes of improving environmental performance while creating commercial value. The IETP provides royalty reductions which are presumed to reduce financial risk. Alberta Energy will be the one to decide which projects qualify and the level of support that will be provided. The deadline for the IETP's third round of applications was May 31, 2007. The successful applicants have not yet been announced and it appears, based on the previous two rounds, that the selection process can take at least 8 months. The technical information gathered from this program is to be made public once a two year confidentiality period expires.

On October 25, 2007, the Alberta government released a report entitled "The New Royalty Framework" (the "**NRF**") containing the government's proposals for Alberta's new royalty regime which is scheduled to be effective on January 1, 2009. The proposed NRF includes new royalty formulas for conventional oil and natural gas that will operate on sliding scales that are determined by commodity prices and well productivity; in addition to the policy of "shallow rights reversion". The Alberta government is intending to implement this policy in order to maximize the development of currently undeveloped resources which is consistent with the government's objective of maximizing recovery of known gas resources, while increasing royalty revenues. The policy's objective is for the mineral rights to shallow gas geological formations that are not being developed to revert back to the government and be made available for resale. It appears that leaseholders will get a grace period before the shallower zones are

reverted to the Crown, which is still to be determined. Substantial legislative, regulatory and systems updates will be introduced before changes become fully effective in January 2009. See *"Risk Factors – Risks to Our Revenues – New Alberta Royalty Regime"*.

### **British Columbia**

Producers of oil and natural gas in the Province of British Columbia are required to pay annual rental payments with respect to the Crown leases and royalties and freehold production taxes in respect of oil and gas produced from Crown and freehold lands. The amount payable as a royalty in respect of oil depends on the type of oil, the value of the oil, the quantity of oil produced in a month, and the vintage of the oil. Generally, 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 rates are calculated in three stages, which take into account the vintage of the oil, if the oil produced has already been sold and any royalty exempt value applicable (exempt wells). Oil produced from newly discovered pools may be exempt from the payment of a royalty for the first 36 months of production or 11,450m<sup>3</sup> produced, whichever comes first; and the royalties for third tier oil are the lowest reflecting the higher costs of exploration and extraction that the producers would incur. The royalty payable on natural gas is determined by a sliding scale based on a reference price, which is the greater of the price obtained by the producer, and a prescribed minimum price. However, when the reference price is below the select price (a parameter used in the royalty rate formula), the royalty rate is fixed. As an incentive for the production and marketing of natural gas, which may have been flared, natural gas produced in association with oil has a lower royalty than the royalty payable on non conservation gas.

On May 30, 2003, the Ministry of Energy and Mines for the Province of British Columbia announced an Oil and Gas Development Strategy for the Heartlands ("**Strategy**"). The Strategy is a comprehensive program to address road infrastructure, targeted royalties and regulatory reduction, and British Columbia service sector opportunities. In addition, the Strategy will result in economic and employment opportunities for communities in British Columbia's heartlands.

Some of the financial incentives in the Strategy include:

- Royalty credits of up to \$30 million annually towards the construction, upgrading, and maintenance of road infrastructure in support of resource exploration and development. Funding will be contingent upon an equal contribution from industry.
- Changes to provincial royalties: new royalty rates for low productivity natural gas to enhance marginally economic resources plays, royalty credits for deep gas exploration to locate new sources of natural gas, and royalty credits for summer drilling to expand the drilling season.

### **Saskatchewan**

In Saskatchewan, the amount payable as a royalty in respect of oil depends on the vintage of the oil, the type of oil, the quantity of oil produced in a month, and the value of the oil. For Crown royalty and freehold production tax purposes, crude oil is considered "heavy oil", "southwest designated oil", or "non-heavy oil other than southwest designated oil". The conventional royalty and production tax classifications ("fourth tier oil" introduced October 1, 2002, "third tier oil", "new oil", or "old oil") of oil production are applicable to each of the three crude oil types. The Crown royalty and freehold production tax structure for crude oil is price sensitive and varies between the base royalty rates of 5% for all "fourth tier oil" to 20% for "old oil". Marginal royalty rates are 30% for all "fourth tier oil" to 45% for "old oil".

The amount payable as a royalty in respect of natural gas is determined by a sliding scale based on a reference price (which is the greater of the amount obtained by the producer and a prescribed minimum price), the quantity produced in a given month, the type of natural gas, and the vintage of the natural gas. 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. The royalty and production tax classifications of gas production are "fourth tier gas" introduced October 1, 2002, "third tier gas", "new gas", and "old gas". The Crown

royalty and freehold production tax for gas is price sensitive and varies between the base royalty rate of 5% for "fourth tier gas" and 20% for "old gas". The marginal royalty rates are between 30% for "fourth tier gas" and 45% for "old gas".

On October 1, 2002, the following changes were made to the royalty and tax regime in Saskatchewan:

- A new Crown royalty and freehold production tax regime applicable to associated natural gas (gas produced from oil wells) that is gathered for use or sale. The royalty/tax will be payable on associated natural gas produced from an oil well that exceeds approximately 65 thousand cubic metres in a month.
- A modified system of incentive volumes and maximum royalty/tax rates applicable to the initial production from oil wells and gas wells with a finished drilling date on or after October 1, 2002, was introduced. The incentive volumes are applicable to various well types and are subject to a maximum royalty rate of 2.5% and a freehold production tax rate of zero percent.
- The elimination of the re entry and short section horizontal oil well royalty/tax categories. All horizontal oil wells with a finished drilling date on or after October 1, 2002, will receive the "fourth tier" royalty/tax rates and new incentive volumes.

In 1975, the Government of Saskatchewan introduced a Royalty Tax Rebate ("**RTR**") as a response to the federal government 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 five years since the federal government had the initiative to reintroduce the full deduction of provincial resource royalties from federal and provincial taxable income.

In June 19, 2007, the Government of Saskatchewan introduced the Orphan Well and Facility Liability Management Program pursuant to the amendment of the *Oil and Gas Conservation Act* and the *Oil and Gas Conservation Regulations*, 1985. The program includes a security deposit, which has two purposes: (i) preventing the individual with insufficient financial capability from acquiring oil and gas wells or facilities; and (ii) in the case of a bankrupt company, the funds cover for the decommissioning and reclaiming of orphan property. An additional change introduced is the mandatory licensing of all upstream oil and gas facilities in Saskatchewan.

### **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 from two years 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.

### **Environmental Regulation**

The oil and natural gas industry is currently subject to environmental regulations pursuant to a variety of provincial and federal legislation. 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. 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.

Environmental legislation in the Province of Alberta has been consolidated into the *Environmental Protection and Enhancement Act* (Alberta) (the "**EPEA**"), which came into force on September 1, 1993, and the *Oil and Gas Conservation Act* (Alberta) (the "**OGCA**"). The EPEA and OGCA impose stricter environmental standards, require more stringent compliance, reporting and monitoring obligations, and significantly increased penalties. In 2006, the

Alberta Government enacted regulations pursuant to the EPEA to specifically target sulphur oxide and nitrous oxide emissions from industrial operations including the oil and gas industry. In addition, the reduction emission guidelines outlined in the *Climate Change and Emissions Management Amendment Act* came into effect on July 1, 2007. Under this legislation, Alberta facilities emitting more than 100,000 tonnes of greenhouse gases a year must reduce their emissions intensity by 12%. Industries have three options to choose from in order to meet the reduction requirements outlined in this legislation, and these are: (i) by making improvement to operations that result in reductions; (ii) by purchasing emission credits from other sectors or facilities that have emissions below the 100,000 tonne threshold and are voluntarily reducing their emission; or (iii) by contributing to the Climate Change and Emissions Management Fund. Industries can either choose one of these options or a combination thereof. We are committed to meeting our responsibilities to protect the environment wherever we operate and anticipate making increased expenditures of both a capital and an expense nature as a result of the increasingly stringent laws relating to the protection of the environment, and will be taking such steps as required to ensure compliance with the EPEA and similar legislation in other jurisdictions in which it operates. We believe that we are in material compliance with applicable environmental laws and regulations. We also believe that it is reasonably likely that the trend towards stricter standards in environmental legislation and regulation will continue.

In January 24, 2008, the Alberta Government announced a new climate change action plan that will cut Alberta's projected 400 million tonnes of emissions in half by 2050. This plan is based on three areas: (i) carbon capture and storage, which will be mandatory for in situ oil sand facilities that use heavy fuels for steam generation; (ii) energy conservation and efficiency; and (iii) greening production through increased investment in clean energy technology, including supporting research on new oil sands extraction processes, as well as the funding of projects that reduce the cost of separating CO<sub>2</sub> from other emissions supporting carbon capture and storage.

British Columbia's *Environmental Assessment Act* became effective June 30, 1995. This legislation rolls the previous processes for the review of major energy projects into a single environmental assessment process with public participation in the environmental review process. On February 27, 2007, the Government of British Columbia unveiled the Energy Plan outlining the Province's strategy towards the environment and which includes targeting for zero net greenhouse gas emissions, promoting new investments in innovation, and becoming the world's leader in sustainable environmental management. For this purpose, on December 18, 2007 proposals were sought for applications to the Innovative Clean Energy Fund, in order to attract new technologies that will help solve energy and environmental issues. With regards to the oil and gas industry the objective is to achieve clean energy through conservation and energy efficient practices, whilst competitiveness is advocated in order to attract investment for the development of the oil and gas sector. Among the changes to be implemented are: (i) a new Net Profit Royalty Program; (ii) the creation of a Petroleum Registry; (iii) the establishment of an infrastructure royalty program (combining roads and pipelines); (iv) the elimination of routine flaring at producing wells; (v) the creation of policies and measures for the reduction of emissions; (vi) the development of unconventional resources such as tight gas and coalbed gas; and (vii) new the Oil and Gas Technology Transfer Incentive Program that encourages the research, development and use of innovative technologies to increase recoveries from existing reserves and promotes responsible development of new oil and gas reserves. Furthering these initiatives, on February 19, 2008 the provincial Government announced that starting on July 1, 2008, provided the legislation is approved; a revenue-neutral carbon tax will be applied to all fossil fuels used in the Province. The tax would be phased in, and the initial rate would be based on CO<sub>2e</sub> of \$10 per tonne for the first six months of 2009 and \$15 per tonne for the last six months of 2009, following \$5 per tonne increases on July of every year until 2012. Tax credits and reductions will be used in order to offset the tax revenues that the Government would receive otherwise.

In December 2002, the Government of Canada ratified the Kyoto Protocol ("**Protocol**"). The Protocol calls for Canada to reduce its greenhouse gas emissions to 6% below 1990 "business-as-usual" levels between 2008 and 2012. Given revised estimates of Canada's normal emissions levels, this target translates into an approximately 40% gross reduction in Canada's current emissions. It is questionable, based on the Updated Action Plan announced by the federal government (see below), that the Kyoto target of 6% below 1990 emission levels will be enforced in Canada. Bill C-288, which is intended to ensure that Canada meets its global climate change obligations under the Kyoto Protocol, was passed by the House of Commons on February 14, 2007. On April 26, 2007, the Federal Government released its Action Plan to Reduce Greenhouse Gases and Air Pollution (the "**Action Plan**") also known as ecoACTION which includes the regulatory framework for air emissions. This Action Plan covers not only large industry, but regulates the fuel efficiency of vehicles and the strengthening of energy standards for a number of energy using products.

The Government of Canada and the Province of Alberta released on January 31, 2008 the final report of the Canada-Alberta ecoENERGY Carbon Capture and Storage Task Force, which recommends among others: (i) incorporating carbon capture and storage into Canada's clean air regulations; (ii) allocating new funding into projects through competitive process; and targeting research to lower the cost of technology.

In order to strengthen the Action Plan, on March 10, 2008, the Government of Canada released "Turning the Corner – Taking Action to Fight Climate Change" (the "**Updated Action Plan**") which provides some additional guidance with respect to the Government's plan to reduce greenhouse gas emissions by 20% by 2020 and by 60% to 70% by 2050.

The Updated Action Plan is primarily directed towards industrial emissions from certain specified industries including the oil sands, oil and gas and refining. The Updated Action Plan is intended to create a carbon emissions trading market, including an offset system, to provide incentive to reduce greenhouse gas emission and establish a market price for carbon. There are mandatory reductions of 18% from the 2006 baseline starting in 2010 and an additional 2% in subsequent years for existing facilities. This target will be applied to regulated sectors on a facility-specific, sector-wide or corporate basis; in the case of oils sands production, petroleum refining, natural gas pipelines and upstream oil and gas the target will be considered facility-specific (sectors in which the facilities are complex and diverse, or where emissions are affected by factors beyond the control of the facility operator). Emissions from new facilities, which are those built between 2004 and 2011, will be based on a cleaner fuel standard to encourage continuous emissions intensity reductions over time, and will be granted a 3-year grace period during which no emissions intensity targets will apply. Targets will begin to apply on the fourth year of commercial operation and the baseline will be the third year's emissions intensity, with a 2% continuous annual emission intensity improvement required. The definition of new facility also includes greenfield facilities, major expansions constituting more than a 25% increase in a facility's physical capacity, as well as transformations to a facility that involve significant changes to its processes. For upstream oil and gas and natural gas pipelines, it will be applied using a sector-specific approach. For the oil sands, its application will be process-specific, oil sands plants built in 2012 and later, those which use heavier hydrocarbons, up-graders and *in-situ* production will have mandatory standards in 2018 that will be based on carbon capture and storage.

In the following regulated sectors, the Updated Action Plan will apply only to facilities exceeding a minimum annual emissions threshold: (i) 50,000 tonnes of CO<sub>2</sub> equivalent per year for natural gas pipelines; (ii) 3,000 tonnes of CO<sub>2</sub> equivalent per upstream oil and gas facilities; and (iii) 10,000 boe/d/company. These proposed thresholds are significantly stricter than the current Alberta regulatory threshold of 100,000 tonnes of CO<sub>2</sub> equivalent per year per facility.

Four separate compliance mechanisms are provided in respect of the above targets: Technology Fund contributions, offset credits, clean development credits and credits for early action. The most significant of these compliance mechanisms, at least initially, will be the Technology Fund and for which regulated entities will be able to contribute in order to comply with emissions intensity reductions. The contribution rate will increase over time, beginning at \$15 per tonne for the 2010-12 period, rising to \$20 per tonne in 2013, and thereafter increasing at the nominal rate of GDP growth. Contribution limits will correspondingly 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 greenhouse gas 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 mentioned 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 cancel the offset credits or bank them 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. 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 metric 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.

Given the evolving nature of the debate related to climate change and the control of greenhouse gases and resulting requirements, it is not currently possible to predict either the nature of those requirements or the impact on us and our operations and financial condition at this time.

### **Federal Tax Changes for Income Trusts and Corporations**

On October 31, 2006, the Finance Minister announced the federal government's plan regarding taxation of income trusts and certain other specified investment flow-through entities ("**SIFTs**"). Currently, distributions paid to unitholders, other than returns of capital, are claimed as a deduction by income trusts in arriving at taxable income whereby tax is eliminated at the trust level and is paid by the unitholders.

The income trust tax legislation relating to SIFTs (the "**SIFT Rules**"), which received Royal assent on June 22, 2007, will result in a two-tiered tax structure whereby distributions from an income trust would first be subject to income taxes commencing in 2011 (or earlier, if any such income trust exceeds the normal growth guidelines announced by the Minister on December 15, 2006), and then unitholders would be subject to tax on the distribution as if it were a taxable dividend paid by a taxable Canadian corporation.

On October 30, 2007, the Finance Minister announced, as part of the 2007 Economic Statement, changes to the tax system including reduction of the corporate income tax rate to 15 percent by 2012. Legislation enacting the measures, announced in the Economic Statement, received Royal assent on December 14, 2007. The reduction in the general corporate tax rate will also be reflected in a lower tax rate on trust distributions.

On December 20, 2007, the Finance Minister announced technical amendments to provide some clarification to the SIFT Rules. As part of the announcement the Minister indicated the federal government intends to provide, in 2008, legislation to permit income trusts to convert to taxable Canadian corporations without any undue tax consequences to the investors or the income trusts.

Currently, the SIFT Rules provide that the SIFT tax rate will be the federal general corporate income tax rate (which is anticipated to be 16.5 percent in 2011 and 15 percent in 2012) plus the provincial SIFT tax factor (which is set at a fixed rate of 13 percent). On February 26, 2008, the Minister of Finance announced (the "**Provincial SIFT Tax Proposal**") that instead of basing the provincial component of the SIFT tax on a flat rate of 13 percent, the provincial component will instead be based on the general provincial corporate income tax rate in each province in which the SIFT has a permanent establishment. Under the Provincial SIFT Tax Proposal, we would likely be considered to have a permanent establishment in Alberta, where the provincial tax rate in 2011 is expected to be 10 percent. There can be no assurance, however, that the Provincial SIFT Tax Proposal will be enacted as proposed.

Our Board of Directors and management continue to review the impact of the SIFT Rules on our business strategy and the merits of converting to a corporation on or before January 1, 2011. We expect future technical interpretations and details will further clarify the legislation. At the present time, we believe that if structural or other similar changes are not made, the after-tax distribution amount in 2011 to taxable Canadian investors will remain approximately the same; however, the after-tax distribution will decline for both tax-deferred Canadian investors (RRSPs, RRIFs, pension plans, etc.) and foreign investors.

For more information, see "*Risk Factors – Risks to Our Revenues – Federal Tax Changes for Income Trusts and Corporations*" and "*Risk Factors – Risks Associated With Government Regulation – Changes in Legislation*".

## Trends

There are a number of trends that have been developing in the oil and gas industry during the past several years that appear to be shaping the near future of the business.

The first trend is the volatility of commodity prices. Natural gas is a commodity influenced by factors within North America. A tight supply-demand balance for natural gas causes significant elasticity in pricing, whereas higher than average storage levels tend to depress natural gas pricing. Drilling activity, weather, fuel switching and demand for electrical generation are all factors that affect the supply-demand balance. Changes to any of these or other factors create price volatility. Crude oil is influenced by the world economy, Organization of the Petroleum Exporting Countries' ability to adjust supply to world demand and weather. Crude oil prices have been kept high by political events causing disruptions in the supply of oil and concern over potential supply disruptions triggered by unrest in the Middle East and more recently have been impacted by weather and increased storage levels. Political events trigger large fluctuations in price levels.

The impact on the oil and gas industry from commodity price volatility is significant. During period of high prices, producers generate sufficient cash flows to conduct active exploration programs without external capital. Increased commodity prices frequently translate into very busy periods for service suppliers triggering premium costs for their services. Purchasing land and properties similarly increase in price during these periods. During low commodity price periods, acquisitions costs drop, as do internally generated funds to spend on exploration and development activities. With decreased demand, the prices charged by the various service suppliers also decline.

A second trend within the Canadian oil and gas industry is the fairly consistent "renewal" of private and small junior oil and gas companies starting up business. These companies often have experienced management teams from previous industry organizations that have disappeared as a part of the ongoing industry consolidation. Many are able to raise capital and recruit well qualified personnel. We will have to compete with these companies and others to attract qualified personnel.

A third trend currently affecting the oil and gas industry is the impact on capital markets caused by investor uncertainty in the North American economy. The capital market volatility in Canada has also been affected by uncertainties surrounding the economic impact that the Protocol, and other environmental initiatives, will have on the sector and in more recent times, by the October 31, 2006 proposals of the Federal government of Canada (the "**October 31, 2006 Proposals**") relating to income trusts and other SIFTs. Pursuant to the existing provisions of the *Income Tax Act* (Canada), to the extent that a SIFT has any income for a taxation year after certain inclusions and deductions, the SIFT will be permitted to deduct all amounts of income which are paid or become payable by it to unitholders in the year. Under the October 31, 2006 Proposals, SIFTs will be liable for tax at a rate consistent with the taxes currently imposed on corporations commencing in January 2011, provided that the SIFT experiences only "normal growth" and no "undue expansion" before then, in which case the tax could be imposed prior to the January 2011 deadline.

During the past few years, the economic recovery combined with increased commodity prices has caused an increase in new equity financings in the oil and gas industry, although the level of same was negatively impacted by the October 31, 2006 Proposals. We will compete with numerous new companies and their new management teams and development plans in its access to capital. The competitive nature of the oil and gas industry will cause opportunities for equity financings to be selective. We may have to rely on internally generated funds to conduct their exploration and developmental programs. In addition to the competitiveness for accessing capital, the industry has experienced a significant increase in the cost structure within the Western Canadian Sedimentary Basin, again largely attributed to the competitiveness in the industry. This increase in cost structure has been offset by higher commodity prices which has led to comparable returns on investments as had been experienced in previous years.

## **RISK FACTORS**

The following is a summary of certain risk factors relating to our business which prospective investors should carefully consider before deciding whether to purchase Trust Units, Exchangeable Shares, 7.5% Convertible Debentures or 6.75% Convertible Debentures.

### **Risks to Our Revenues**

#### ***Volatility of Oil and Natural Gas Prices***

The operational results and financial condition of our operating entities and therefore the amounts paid to us, will be dependent on the prices received for oil and natural gas production. Oil and natural gas prices have fluctuated widely during recent years and are determined by economic and in the case of oil prices, political factors and a variety of additional factors beyond our control. These factors include economic conditions, in the United States and Canada, the actions of the Organization of Petroleum Exporting Countries, governmental regulation, political stability in the Middle East and elsewhere, the foreign supply of oil and natural gas, risks of supply disruption, the price of foreign imports and the availability of alternative fuel sources. Any substantial and extended decline in the price of oil and gas would have an adverse effect on our carrying value of our proved and probable reserves, borrowing capacity, revenues, profitability and cash flows from operating activities. Any movement in oil and natural gas prices could have an effect on our financial condition and therefore on the amounts to be distributed to our Unitholders. We may manage the risk associated with changes in commodity prices by entering into oil or natural gas price hedges. If we hedge our commodity price exposure, we will forego the benefits we would otherwise experience if commodity prices were to increase. In addition, commodity hedging activities could expose us to losses. As at December 31, 2007, our balance sheet reflected \$45.1 million of unrealized commodity losses resulting from hedges to protect our commodity risk exposure. To the extent that we engage in risk management activities related to commodity prices, we will be subject to credit risks associated with counterparties with which we contract.

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. See "*Risk Factors – Risks Associated with Acquisitions and Expansion – Purchase of Properties*" and "*Risk Factors – Operational Risks – Project Risks*".

#### ***Federal Tax Changes for Income Trusts and Corporations***

New legislation passed in June 2007, will apply a SIFT tax at the trust level on distributions of certain income from trusts, such as us, at rates of tax comparable to the combined federal and provincial corporate tax and will treat such distributions as dividends to the unitholders. The SIFT tax results in adverse tax consequences to us and certain Unitholders (including most particularly Unitholders that are tax deferred or non-residents of Canada) and may impact cash distributions from us.

Generally, there will be a four year transition period for an existing trust, such as us, and the tax under the new legislation will not apply until January 1, 2011. However, the new legislation provides that there are circumstances under which an existing trust may lose its transitional relief before 2011, including where the "normal growth" of a trust existing on October 31, 2006 is exceeded.

"Normal growth" includes equity growth within certain "safe harbour" limits, measured by reference to a SIFT trust's market capitalization as of the end of trading on October 31, 2006 (which would include only the market value of the SIFT's issued and outstanding publicly-traded trust units, and not any convertible debt, options or other interests convertible into or exchangeable for trust units). Those safe harbour limits are 40% for the period from November 1, 2006 to December 31, 2007, and 20% each for calendar 2008, 2009 and 2010. Moreover, these limits are cumulative, so that any unused limit for a period carries over into the subsequent period. For us, the growth limits are approximately \$1.7 billion for 2007 and an additional approximately \$567 million for each of 2008, 2009 and 2010 with any unused amount rolling forward to the next year.

While the normal growth restrictions are such that it is unlikely they would affect our ability to raise the capital required to maintain and grow our existing operations in the ordinary course during the transition period, they could adversely affect the cost of raising capital and our ability to undertake more significant acquisitions. The SIFT tax has reduced the value of the Trust Units, which has increased the cost to us of raising capital in the public capital markets. In addition management of Bonavista Petroleum believes that the SIFT tax: (a) substantially eliminates the competitive advantage that we and other Canadian energy trusts enjoyed relative to their corporate peers in raising capital in a tax-efficient manner, and (b) places us and other Canadian energy trusts at a competitive disadvantage relative to industry competitors, including U.S. master limited partnerships, which will continue to not be subject to entity level taxation. The new legislation also makes the Trust Units less attractive as an acquisition currency. As a result, it may become more difficult for us to compete effectively for acquisition opportunities. There can be no assurance that we will be able to reorganize our legal and tax structure to substantially mitigate the expected impact of the SIFT tax.

No assurance can be provided that the SIFT tax will not apply to us prior to January 1, 2011, or that the legislation will not be further changed in a manner which affects us and our Unitholders. See "*Risk Factors – Risks Associated With Government Regulation – Changes in Legislation*".

### ***New Alberta Royalty Regime***

On October 25, 2007, the Alberta government released a report entitled "The New Royalty Framework" containing the government's proposals for Alberta's new royalty regime which is scheduled to be effective on January 1, 2009. Given that the NRF has only recently been announced, it is not possible at this time to determine the full impact of the NRF on our financial condition and operations and in particular the extent to which the Proposed Royalty Regime will reduce our cash flow, which will in turn reduce the cash otherwise available for distribution by us to our Unitholders.

The NRF includes the following features:

- New, simplified royalty formulas for conventional oil and natural gas that will operate on sliding scales that are determined by commodity prices and well productivity. The formulas eliminate the need for conventional oil and natural gas tiers and several royalty exemption programs.
- A sliding scale will be implemented for oil sands royalty rates ranging from one to nine percent pre-payout and 25 to 40 percent post-payout depending on the price of oil.
- The province will exercise its existing right to receive "royalty-in-kind" on oil sands projects (i.e. raw bitumen delivered to the Crown-operated Alberta Petroleum Marketing Commission in lieu of cash royalties).
- The government will ensure that eligible expenditures and definitions of oil sands projects (also known as "ring fence" definition) that determine when a project has reached payout are tightly and clearly defined. Environmental "costs of doing business" will continue to be recognized as eligible expenditures.
- No grandfathering will be implemented for existing oil sands projects.
- Substantial legislative, regulatory and systems updates will be introduced before changes become fully effective in January 2009.

We cannot provide any assurance that the NRF will be implemented in the form proposed. If changes are made to the NRF before it is implemented by the Alberta government, such changes could result in the implementation of a new royalty regime that impacts us in a materially different manner, and that is more adverse to us, than the NRF as currently proposed. See "*Risk Factors – Risks Associated With Government Regulation – Changes in Legislation*".

### ***Hedging***

From time to time we may enter into agreements to receive fixed prices on our 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, we will not benefit from such increases and we may nevertheless be obligated to pay royalties on such higher prices, even though not received by us, after giving effect to such agreements. Similarly, from time to time we 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, we will not benefit from the fluctuating exchange rate.

### ***Marketing***

The marketability and price of oil and natural gas that may be acquired or discovered by us will be affected by numerous factors beyond our control. These factors include demand for oil and natural gas, market fluctuations, the proximity and capacity of oil and natural gas pipelines and processing equipment and government regulations, including regulations relating to environmental protection, royalties, allowable production, pricing, importing and exporting of oil and natural gas.

### ***Variations in Interest Rates and Foreign Exchange Rates***

An increase in interest rates could result in a significant increase in the amount we pay to service debt, resulting in a decrease in distributions to Unitholders, as well as impact the market price of the Trust Units.

World oil 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 that may fluctuate over time. A material increase in the value of the Canadian dollar may negatively impact our net production revenue.

In addition, the exchange rate for the Canadian dollar versus the U.S. dollar has increased significantly over the last 12 months, resulting in our receipt of fewer Canadian dollars for our production which may affect future distributions. We have initiated certain hedges to attempt to mitigate these risks. To the extent that we engage in risk management activities related to foreign exchange rates, it will be subject to credit risk associated with counterparties with which we contract. The increase in the exchange rate for the Canadian dollar and future Canadian/United States exchange rates will impact future distributions and the future value of our reserves as determined by our independent evaluator.

### ***Geo-Political Risks***

The marketability and price of oil and natural gas that may be acquired or discovered by us 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 our net production revenue.

In addition, our oil and natural gas properties, wells and facilities could be subject to a terrorist attack. If any of our properties, wells or facilities are the subject of terrorist attack it could have a material adverse effect on our financial condition. We do not have insurance to protect against the risk from terrorism.

### ***Third Party Credit Risk***

We may be exposed to third party credit risk through our contractual arrangements with our current or future joint venture partners, marketers of our petroleum and natural gas production and other parties. In the event such entities fail to meet their contractual obligations to us, such failures could have a material adverse effect on us and our cash flow from operations. In addition, poor credit conditions in the industry and of joint venture partners may impact a

joint venture partner's willingness to participate in our ongoing capital program, potentially delaying the program and the results of such program until we find a suitable alternative partner.

### ***Delay in Cash Receipts***

In addition to the usual delays in payment by purchasers of oil and natural gas to the operators of the properties, and by the operator to our operating entities, payments between any of such parties may also be delayed by restrictions imposed by lenders, delays in the sale or delivery of products, delays in the connection of wells to a gathering system, blowouts or other accidents, recovery by the operator of expenses incurred in the operation of properties or the establishment by the operator of reserves for such expenses.

### **Operational Risks**

#### ***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. Our long-term commercial success depends on our ability to find, acquire, develop and commercially produce oil and natural gas reserves. Without the continual addition of new reserves, any existing reserves we may have at any particular time, and the production therefrom will decline over time as such existing reserves are exploited. A future increase in our reserves will depend not only on our ability to explore and develop any properties we may have from time to time, but also on our ability to select and acquire suitable producing properties or prospects. No assurance can be given that we will be able to continue to locate satisfactory properties for acquisition or participation. Moreover, if such acquisitions or participations are identified, our management 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 us.

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, we 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. In accordance with industry practice, we are not fully insured against all of these risks, nor are all such risks insurable. Although we maintain liability insurance in an amount that we considers consistent with industry practice, the nature of these risks is such that liabilities could exceed policy limits, in which event we could incur significant costs that could have a material adverse effect upon our financial condition. 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 could have a material adverse effect on our financial condition.

Exploration and development risks arise due to the uncertain results of searching for and producing oil and natural gas using imperfect scientific methods. These risks are mitigated by using highly skilled staff, focusing exploration efforts in areas in which we have existing knowledge and expertise or access to such expertise, using up to date technology to enhance methods, and controlling costs to maximize returns.

### ***Operating Costs and Production Declines***

Higher operating costs for our underlying properties will directly decrease the amount of cash flow received by us and, therefore, may reduce distributions to our Unitholders. Electricity, chemicals, supplies, reclamation and abandonment and labour costs are a few of our operating costs that are susceptible to material fluctuation.

The level of production from our existing properties may decline at rates greater than anticipated due to unforeseen circumstances, many of which are beyond our control. A significant decline in production could result in materially lower revenues and cash flow and, therefore, could reduce the amount available for distributions to Unitholders.

### ***Operational Dependence***

Other companies operate some of the assets in which we have an interest. As a result, we will have limited ability to exercise influence over the operation of those assets or their associated costs, which could adversely affect our financial performance. Our return on assets operated by others will therefore depend upon a number of factors that may be outside of our 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***

We will manage a variety of small and large projects in the conduct of our business. Project delays may delay expected revenues from operations. Significant project cost over-runs could make a project uneconomic. Our ability to execute projects and market oil and natural gas will depend upon numerous factors beyond our 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, we 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 we produce.

### ***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 us and

may delay exploration and development activities. To the extent we are not the operator of our oil and gas properties, we will be dependent on such operators for the timing of activities related to such properties and will be largely unable to direct or control the activities of the operators.

### ***Seasonality***

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

### ***Reserves Estimates***

There are numerous uncertainties inherent in estimating quantities of oil, natural gas and natural gas liquids reserves and resources and the future cash flows attributed to such reserves, including many factors beyond our control. In general, estimates of economically recoverable oil and natural gas reserves and resources and the future net revenues therefrom are based upon a number of variable factors and assumptions, such as historical production from the properties, production rates, ultimate reserve recovery, timing and amount of capital expenditures, marketability of oil and natural gas, royalty rates, the assumed effects of regulation by governmental agencies and future operating costs, all of which may vary materially from actual results. All such estimates are to some degree speculative, and classifications of reserves are only attempts to define the degree of speculation involved. For those reasons, estimates of the economically recoverable oil and natural gas reserves or estimates of resources 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.

Estimates of proved reserves that may be developed and produced in the future are sometimes 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, GLJ and Ryder Scott have used forecast price and cost estimates in calculating reserve quantities included in this Annual Information Form. 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 reserves will vary from the reserves estimates contained in the engineering report summarized in this Annual Information Form, and such variations could be material. The estimates in such engineering report is based in part on the timing and success of activities we intend to undertake in future years. The reserves and estimated cash flows to be derived therefrom contained in the engineering reports summarized in this Annual Information Form will be reduced, in future years, to the extent that such activities do not achieve the level of success assumed in the engineering reports summarized in this Annual Information Form.

The reserves and recovery information contained in the GLJ Report and the Ryder Report are only estimates and the actual production and ultimate reserves from the properties may be greater or less than the estimates prepared by GLJ and Ryder Scott. The GLJ Report and the Ryder Report have been prepared using certain commodity price assumptions which are described in the notes to the reserves tables. If we realize lower prices for crude oil, natural gas liquids and natural gas and they are substituted for the price assumptions utilized in those reserves reports, the present value of estimated future net cash flows for our reserves would be reduced and the reduction could be significant.

***Depletion of Reserves***

Distributions of distributable income in respect of properties, absent commodity price increases or cost effective acquisition and development activities, will decline over time in a manner consistent with declining production from typical oil, natural gas and natural gas liquids reserves. We will not be reinvesting cash flow from operating activities in the same manner as other industry participants as we conduct only minimal exploratory activities; nor to the same extent as other industry participants as one of our main objectives is to maximize long-term distributions. Accordingly, absent capital injections, our initial production levels and reserves will decline and the level of distributable income will be reduced.

Our future oil and natural gas reserves and production, and therefore our cash flows from operating activities, will be highly dependent on our success in exploiting our reserves base and acquiring additional reserves. Without reserves additions through acquisition or development activities, our reserves and production will decline over time as reserves are produced.

To the extent that external sources of capital, including the issuance of additional Trust Units become limited or unavailable, our ability to make the necessary capital investments to maintain or expand our oil and natural gas reserves will be impaired. To the extent that we are required to use cash flow from operating activities to finance capital expenditures or property acquisitions, the level of distributable income will be reduced.

There can be no assurance that we will be successful in developing or acquiring additional reserves on terms that meet our investment objectives.

***Insurance***

Our involvement in the exploration for and development of oil and natural gas properties may result in us becoming subject to liability for pollution, blow outs, property damage, personal injury or other hazards. Although prior to drilling our operating entities will obtain insurance in accordance with industry standards to address certain of these risks, such insurance has limitations on liability that may not be sufficient to cover the full extent of such liabilities. In addition, such risks may not in all circumstances be insurable or, in certain circumstances, our operating entities 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 such uninsured liabilities would reduce the funds available to us. The occurrence of a significant event that we are not fully insured against, or the insolvency of the insurer of such event, could have a material adverse effect on our financial position, results of operations or prospects and will reduce income otherwise distributable to us.

***Competition***

There is strong competition relating to all aspects of the oil and gas industry. There are numerous trusts in the oil and gas industry, who are competing for the acquisitions of properties with longer life reserves, properties with exploitation and development opportunities and undeveloped land. As a result of such competition, it will be more difficult to acquire reserves on beneficial terms. We also compete for reserves acquisitions and undeveloped land with a substantial number of other oil and gas companies, many of which have significantly greater financial and other resources than we do.

We compete with other oil and gas entities to hire and retain skilled personnel necessary for running of daily operations of the Trust including the execution of the annual capital development program. The inability to hire and retain skilled personnel could adversely impact certain of our operational and financial results.

***Risks Associated with Government Regulation******Environmental Concerns***

The oil and natural gas industry is subject to environmental regulation pursuant to local, provincial and federal legislation. A breach of such legislation may result in the imposition of fines or issuance of clean up orders in

respect of us or our properties. Such legislation may be changed to impose higher standards and potentially more costly obligations on us. Furthermore, management believes the political climate appears to favour new programs for environmental laws and regulation, particularly in relation to the reduction of emissions, and there is no assurance that any such programs, laws or regulations, if proposed and enacted, will not contain emission reduction targets which we cannot meet, and financial penalties or charges could be incurred as a result of the failure to meet such targets or taxes based upon such emissions. In particular there is uncertainty regarding the *Government of Canada's Clean Air Act of 2006*. The Clean Air Act proposes to reduce greenhouse gas emissions, however emission targets and compliance deadlines differ from those outlined in the Kyoto Protocol which was ratified by Canada. If passed, the Clean Air Act may have adverse operational and financial implications to us. See "*Industry Conditions – Environmental Regulation*". Based on our current knowledge, there can be no assurance that we will be able to satisfy our actual future environmental and reclamation obligations.

Provincial emission reduction requirements, such as those in Alberta's *Climate Change and Emissions Management Amendment Act*, may require the reduction of emissions or emissions intensity of our operations and facilities. The direct or indirect costs of these regulations may adversely and materially affect our business. See "*Industry Conditions – Environmental Regulation*".

Canada is a signatory to the United Nations Framework Convention on Climate Change and in December 2002 the Government of Canada ratified the Kyoto Protocol and it became legally binding on February 16, 2005. This protocol calls for Canada to reduce its greenhouse gas emissions to six percent below 1990 levels during the period between 2008 and 2012. Our exploration and production facilities and other operations and activities emit greenhouse gases that may subject us to legislation regulating emissions of greenhouse gases. The Government of Canada has put forward a Climate Change Plan for Canada which suggests further legislation will set greenhouse gases emission reduction requirements for various industrial activities, including oil and gas exploration and production. 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. Implementation of strategies for reducing greenhouse gases whether to meet the limits required by the Kyoto Protocol or as otherwise determined, could have a material impact on the nature of oil and natural gas operations, including ours. 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 either the nature of those requirements or the impact on us and our operations and financial condition. See "*Risk Factors – Risks Associated With Government Regulation – Change of Legislation*".

Although we believe that we are 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 adversely affect our financial condition, results of operations or prospects. Future changes in other environmental legislation could occur and result in stricter standards and enforcement, larger fines and liability, and increased capital expenditures and operating costs, which could have a material adverse effect on our financial condition or results of operations. See "*Industry Conditions – Environmental Regulation*".

### **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. 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 our costs, any of which may have a material adverse effect on our business, financial condition and results of operations. In order to conduct oil and gas operations, we will require licenses from various governmental authorities. There can be no assurance that we will be able to obtain all of the licenses and permits that may be required to conduct operations that we may wish to undertake. See "*Industry Conditions*".

### ***Changes in Legislation***

Income tax laws, or other laws or government incentive programs relating to the oil and gas industry, such as the treatment of mutual fund trusts and resource taxation, may in the future be changed or interpreted in a manner that adversely affects us and our Unitholders. Tax authorities having jurisdiction over us or Unitholders may disagree with how we calculate our income for tax purposes or could change administrative practises to our detriment or the detriment of Unitholders.

We intend to continue to qualify as a mutual fund trust for purposes of the *Income Tax Act* (Canada). We may not, however, always be able to satisfy any future requirements for the maintenance of mutual fund trust status. Should our status as a mutual fund trust be lost or successfully challenged by a relevant tax authority, certain adverse consequences may arise for us and Unitholders. Some of the significant consequences of losing mutual fund trust status are as follows:

- We would be taxed on certain types of income distributed to Unitholders, including income generated by the NPI held by us. Payment of this tax may have adverse consequences for some Unitholders, particularly Unitholders that are not residents of Canada and residents of Canada that are otherwise exempt from Canadian income tax.
- We would cease to be eligible for the capital gains refund mechanism available under Canadian tax laws if it ceased to be a mutual fund trust.
- Trust Units held by Unitholders that are not residents of Canada would become taxable Canadian property. These non-resident holders would be subject to Canadian income tax on any gains realized on a disposition of Trust Units held by them.
- Trust Units would not constitute qualified investments for registered retirement savings plans ("RRSPs"), registered retirement income funds ("RRIFs"), registered education savings plans ("RETSs") or deferred profit sharing plans ("DPSPs"). If, at the end of any month, one of these exempt plans holds Trust Units that are not qualified investments, the plan must pay a tax equal to one percent of the fair market value of the Trust Units at the time the Trust Units were acquired by the exempt plan. An RRSP or RRIF holding non-qualified Trust Units would be subject to taxation on income attributable to the Trust Units. If an RESP holds non-qualified Trust Units, it may have its registration revoked by the Canada Revenue Agency.

In addition, we may take certain measures in the future to the extent we believe necessary to ensure that we maintain the status as a mutual fund trust. These measures could be adverse to certain holders of Trust Units, particularly non-residents of Canada as defined in the *Income Tax Act* (Canada).

For more information, see "*Risk Factors – Risks Associated With Government Regulation – Non-resident Ownership of Trust Units*", "*Risk Factors – Risks to Our Revenues – Federal Tax Changes for Income Trusts and Corporations*", "*Risk Factors – Environmental Concerns*", and "*Industry Conditions – Environmental Regulation*".

### ***Non-resident Ownership of Trust Units***

We intend to comply with the requirements under the *Income Tax Act* (Canada) for "unit trusts" and "mutual fund trusts" at all relevant times such that we maintain our status of a unit trust and a mutual fund trust for purposes of the *Income Tax Act* (Canada). In this regard, we may, from time to time, among other things, take all necessary steps to monitor our activities and ownership of the Trust Units. If at any time we become aware that our activities and ownership of the Trust Units by non-residents (non-residents of Canada and partnerships) may threaten our status under the *Income Tax Act* (Canada) as a "unit trust" or "mutual fund trust", we are authorized to take such action as may be necessary in our opinion to maintain our status as a unit trust and a mutual fund trust, including the imposition of restrictions on the issuance by us, or the transfer by any Unitholder, of Trust Units to a non resident. See "*Information Relating To Us – The Trust Indenture – Limitations on Non-Resident Ownership*" and "*Risk Factors – Risks Associated With Government Regulation – Change of Legislation*".

### ***Expiration of Licences and Leases***

Our properties are held in the form of licences and leases and working interests in licences and leases. If we 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 our licences or leases or the working interests relating to a licence or lease may have a material adverse effect on our results of operations and business.

### **Risks Associated with Acquisitions and Expansion**

#### ***Purchase of Properties***

The price we pay for the purchase of properties is based on engineering and economic estimates of the reserves made by independent engineers modified to reflect our technical and economic views. These assessments include a number of material assumptions regarding such factors as recoverability and marketability of oil, natural gas, natural gas liquids and sulphur, future prices of oil, natural gas, natural gas liquids and sulphur and operating costs, future capital expenditures and royalties and other government levies which will be imposed over the producing life of the reserves. Many of these factors are subject to change and are beyond our control and the control of the operators of the properties. In particular, changes in the prices of and markets for petroleum, natural gas, natural gas liquids and sulphur from those anticipated at the time of making such assessments will affect the amount of future distributions and as such the value of the Trust Units. In addition, all such estimates involve a measure of geological and engineering uncertainty which could result in lower production and reserves than attributed to the properties. Actual reserves could vary materially from these estimates. Consequently, the reserves acquired may be less than expected, which could adversely impact cash flows and distributions to Unitholders.

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

We make 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 our ability to realize the anticipated growth opportunities and synergies from combining the acquired businesses and operations with those of our operations. 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 we can focus our efforts and resources more efficiently. Depending on the state of the market for such non core assets, certain of our non core assets, if disposed of, could realize less than their carrying value on our financial statements.

#### ***Expansion of Operations***

Our operations and expertise are currently focused on conventional oil and gas production and development in the Western Canadian Sedimentary Basin. In the future, we may acquire oil and gas properties outside of this geographic area. In addition, the Trust Indenture does not limit our activities to oil and gas production and development, and we could acquire other energy related assets, such as oil and natural gas processing plants or pipelines, or an interest in an oil sands project. Expansion of our activities into new areas may present new additional risks or alternatively, significantly increase the exposure to one or more of the present risk factors which may adversely affect our future operational and financial conditions.

### **Title Risks**

#### ***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 our claim which could result in a reduction of the revenue received by us.

***Aboriginal Claims***

Aboriginal peoples have claimed aboriginal title and rights to portions of western Canada. We are not aware that any material claims have been made in respect of its properties and assets; however, if a claim arose and was successful this could have an adverse effect on our and our operations.

**Management Risks*****Reliance on Key Personnel***

Our success depends in large measure on certain key personnel. The loss of the services of such key personnel could have a material adverse affect on us. The contributions of the existing management team to the immediate and near term operations 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 we will be able to continue to attract and retain all personnel necessary for the development and operation of our business. Investors must rely upon the ability, expertise, judgment, discretion, integrity and good faith of our management.

***Reliance on Management***

Unitholders will be dependent on our management in respect of the administration and management of all matters relating to our properties and Trust Units. As of December 31, 2007, we operated approximately 80 percent of the total daily production of our properties. Investors who are not willing to rely on our management should not invest in Trust Units.

***Management of Growth***

We may be subject to growth-related risks including capacity constraints and pressure on our internal systems and controls. Our ability to manage growth effectively will require us to continue to implement and improve our operational and financial systems and to expand, train and manage our employee base. Our inability to deal with this growth could have a material adverse impact on our business, operations and prospects.

***Conflicts of Interest***

The directors or officers of Bonavista Petroleum may also be directors or officers of other oil and natural gas companies or otherwise involved in natural resource exploration and development and situations may arise where they are in a conflict of interest with us. Conflicts of interest, if any, which arise will be subject to and governed by procedures prescribed by the *Business Corporations Act* (Alberta) 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 us 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 *Business Corporations Act* (Alberta).

**Capital Risks*****Substantial Capital Requirements***

We anticipate making substantial capital expenditures for the acquisition, exploration, development and production of oil and natural gas reserves in the future. If our revenues or reserves decline, we may not have access to the capital necessary to undertake or complete future drilling programs. There can be no assurance that debt or equity financing, or cash generated by operations will be available or sufficient to meet these requirements or for other our purposes or, if debt or equity financing is available, that it will be on terms acceptable to us. Our inability to access sufficient capital for our operations could have a material adverse effect on our financial condition, results of operations and prospects.

### ***Issuance of Debt***

From time to time we 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 our debt levels above industry standards for oil and natural gas companies of similar size. Depending on future exploration and development plans, we 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 Trust Indenture nor the constating documents of our controlled entities limit the amount of indebtedness that we may incur. The level of our indebtedness from time to time, could impair our ability to obtain additional financing on a timely basis to take advantage of business opportunities that may arise.

### ***Debt Service***

Amounts paid in respect of interest and principal on debt we have incurred will reduce income available for distributions. Variations in interest rates and scheduled principal repayments could result in significant changes in the amount required to be applied to debt service before payment of the NPI. Certain covenants of the agreements with our lenders may also limit distributions. Although we believe our credit facilities will be sufficient for our immediate requirements, there can be no assurance that the amount will be adequate for our future financial obligations or that additional funds will be able to be obtained.

Our lenders have or will be provided with security over substantially all of our assets. If we become unable to pay our debt service charges or otherwise commits an event of default such as bankruptcy, our lenders may foreclose on or sell our oil and natural gas assets.

### ***Additional Financing***

In the normal course of making capital investments to maintain and expand our oil and gas reserves additional Trust Units are issued from treasury which may result in a decline in production per Trust Unit and reserves per Trust Unit. Additionally, from time to time we may issue Trust Units from treasury in order to reduce debt and maintain a more optimal capital structure. Conversely to the extent that external sources of capital, including the issuance of additional Trust Units become limited or unavailable, our ability to make the necessary capital investments to maintain or expand our oil and gas reserves will be impaired. Management believes that SIFT tax imposed by the Government of Canada will substantially eliminate the competitive advantage that we and other energy trusts have enjoyed relative to our industry competitors in raising capital in a tax-efficient manner. See "*Risk Factors – Risks to Our Revenues – Federal Tax Changes to Income Trusts and Corporations*". To the extent that we are required to use cash flow from operating activities to finance capital expenditures or property acquisitions or to pay debt service charges or to reduce debt, the level of cash flow from operating activities available for distribution to Unitholders will be reduced.

### ***Dilution***

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

### ***Net Asset Value***

The net asset value of our assets from time to time will vary dependent upon a number of factors beyond the control of management, including oil and gas prices. The trading prices of the Trust Units from time to time is also determined by a number of factors which are beyond the control of management and such trading prices may be greater than the net asset value of our assets.

### ***Prior Ranking Indebtedness; Absence of Covenant Protection***

The 7.5% Convertible Debentures and the 6.75% Convertible Debentures are subordinate to all senior indebtedness and to any indebtedness of our creditors. The payment of principal and interest on the 7.5% Convertible Debentures and the 6.75% Convertible Debentures are subordinated to the senior indebtedness of us and to indebtedness of our

trade creditors. The 7.5% Convertible Debentures and the 6.75% Convertible Debentures are also effectively subordinate to claims of creditors of our subsidiaries except to the extent we are a creditor of such subsidiaries ranking at least *pari passu* with such other creditors.

The indenture governing the 7.5% Convertible Debentures and the 6.75% Convertible Debentures does not limit our ability to incur additional liabilities (including senior indebtedness) or to make distributions, except, in respect of distributions, where an event of default has occurred or would occur and such default has not been cured or waived. The 7.5% Convertible Debentures and the 6.75% Convertible Debentures do not contain any provision specifically intended to protect holders of the 7.5% Convertible Debentures and the 6.75% Convertible Debentures in the event of a future leveraged transaction involving Bonavista Petroleum.

## **Risks Associated with Our Structure as a Trust**

### ***Return of Capital***

Trust Units will have no value when reserves from the properties can no longer be economically produced and, as a result, distributions do not represent a "yield" in the traditional sense and are not comparable to bonds or other fixed yield securities, where investors are entitled to a full return of the principal amount of debt on maturity in addition to a return on investment through interest payments. Distributions represent a blend of return of Unitholders initial investment and a return on Unitholders initial investment.

Unitholders have a limited right to require a repurchase of their Trust Units, which is referred to as a redemption right. See "*Information Relating to Us – Right of Redemption*". It is anticipated that the redemption right will not be the primary mechanism for Unitholders to liquidate their investment. The right to receive cash in connection with a redemption is subject to limitations. Any securities which may be distributed in specie to Unitholders in connection with a redemption may not be listed on any stock exchange and a market may not develop for such securities. In addition, there may be resale restrictions imposed by law upon the recipients of the securities pursuant to the redemption right.

### ***Nature of Trust Units***

The Trust Units do not represent a traditional investment in the oil and natural gas sector and should not be viewed by investors as shares in Bonavista Petroleum. The Trust Units represent a fractional interest in the Trust. Corporate law does not govern the Trust and the rights of Unitholders. As holders of Trust Units, Unitholders will not have the statutory rights normally associated with ownership of shares of a corporation including, for example, the right to bring oppression or derivative actions. The rights of Unitholders are specifically set forth in the Trust Indenture. In addition, trusts are not defined as recognized entities within the definitions of legislation such as the *Bankruptcy and Insolvency Act* (Canada), the *Companies' Creditors Arrangement Act* (Canada) and in some cases the *Winding Up and Restructuring Act* (Canada). As a result, in the event of an insolvency or restructuring, a Unitholder's position as such may be quite different than that of a shareholder of a corporation. Our sole assets will be the NPI and other investments in securities of our operating entities. The price per Trust Unit is a function of anticipated distributable income, the properties acquired by us and our ability to effect long-term growth in our value. The market price of the Trust Units will be sensitive to a variety of market conditions including, but not limited to, interest rates and our ability to acquire suitable oil and natural gas properties. Changes in market conditions may adversely affect the trading price of the Trust Units.

The Trust Units are also unlike conventional debt instruments in that there is no principal amount owing to Unitholders. The Trust Units will have minimal value when reserves from our properties can no longer be economically produced or marketed. Unitholders will only be able to obtain a return of the capital they invested during the period when reserves may be economically recovered and sold. Accordingly, the distributions received over the life of the investment may not be equal to or greater than the initial capital investment.

The Trust Units are not "deposits" within the meaning of the *Canada Deposit Insurance Corporation Act* (Canada) and are not insured under the provisions of that Act or any other legislation. Furthermore, we are not a trust

company and, accordingly, are not registered under any trust and loan company legislation as we do not carry on or intend to carry on the business of a trust company.

### ***Unitholder Limited Liability***

The Trust Indenture provides that no Unitholder will be subject to any liability in connection with us or our obligations and affairs and, in the event that a court determines Unitholders are subject to any such liabilities, the liabilities will be enforceable only against, and will be satisfied only out of our assets. Pursuant to the Trust Indenture, we will indemnify and hold harmless each Unitholder from any costs, damages, liabilities, expenses, charges and losses suffered by a Unitholder resulting from or arising out of such Unitholder not having such limited liability.

The Trust Indenture provides that all written instruments signed by or on behalf of the Trust must contain a provision to the effect that such obligation will not be binding upon Unitholders personally. Personal liability may also arise in respect of claims against us that do not arise under contracts, including claims in tort, claims for taxes and possibly certain other statutory liabilities. The possibility of any personal liability of this nature arising is considered unlikely. The *Income Trusts Liability Act* (Alberta) came into force on July 1, 2004. The legislation provides that a unitholder will not be, as a beneficiary, liable for any act, default, obligation or liability of the trustee that arises after the legislation came into force.

Our operations will be conducted, upon the advice of counsel, in such a way and in such jurisdictions as to avoid as far as possible any material risk of liability on Unitholders for claims against us.

### ***Maintenance of Distributions***

We add to our oil and natural gas reserves primarily through low risk development and acquisitions with only a small percentage of our capital directed to exploration. As a result, future oil and natural gas reserves are highly dependent on our operating entities success in exploiting existing properties and acquiring additional reserves. We also distribute the majority of our net cash flow to Unitholders rather than reinvesting it in reserve additions. Accordingly, if external sources of capital, including the issuance of additional Trust Units, become limited or unavailable on commercially reasonable terms, our operating entities ability to make the necessary capital investments to maintain or expand their oil and natural gas reserves will be impaired. To the extent that our operating entities are required to use cash flow to finance capital expenditures or property acquisitions, the level of cash flow available for distribution to Unitholders will be reduced. Additionally, we cannot guarantee that we will be successful in developing additional reserves or acquiring additional reserves on terms that meet our investment objectives. Without these reserve additions, our reserves will deplete and as a consequence, either production from, or the average reserve life of, our properties will decline. Either decline may result in a reduction in the value of Trust Units and in a reduction in cash available for distributions to Unitholders.

### ***Allocation of Trust Income***

Pursuant to the provisions of the Trust Indenture all income earned by us in a fiscal year, not previously distributed in that fiscal year, must be distributed to Unitholders of record on December 31. This excess income, if any, will be allocated to Unitholders of record at December 31 but the right to receive this income, if the amount is not determined and declared payable at December 31, will trade with the Trust Units until determined and declared payable in accordance with the rules of the Toronto Stock Exchange. To the extent that a Unitholder trades Trust Units in this period they will be allocated such income but will dispose of their right to receive such distribution.

### ***Accounting Write-Downs as a Result of GAAP***

Canadian Generally Accepted Accounting Principles ("GAAP") require that management apply certain accounting policies and make certain estimates and assumptions which affect reported amounts in our consolidated financial statements. The accounting policies may result in non-cash charges to net income and write-downs of net assets in the financial statements. Such non-cash charges and write-downs may be viewed unfavourably by the market and may result in an inability to borrow funds and/or may result in a decline in the Trust Unit price.

Under GAAP, the net amounts at which petroleum and natural gas costs on a property or project basis are carried are subject to a cost-recovery test which is based in part upon estimated future net cash flows from reserves. If net capitalized costs exceed the estimated recoverable amounts, we will have to charge the amounts of the excess to earnings. A decline in the net value of oil and natural gas properties could cause capitalized costs to exceed the cost ceiling, resulting in a charge against earnings. The net value of oil and gas properties are highly dependent upon the prices of oil and natural gas. See "*Risk Factors – Risks to Our Revenues – Volatility of Oil and Natural Gas Prices*".

GAAP requires that goodwill balances be assessed at least annually for impairment and that any permanent impairment be charged to net income. A permanent reduction in reserves, decline in commodity prices, and/or reduction in the Trust Unit price may indicate goodwill impairment. As at December 31, 2007 we had \$41.3 million recorded on our balance sheet. An impairment would result in a write-down of the goodwill value and a non-cash charge against net income. The calculation of impairment value is subject to management estimates and assumptions.

New GAAP surrounding accounting for derivatives may result in non-cash charges against net income as a result of changes in the fair market value of derivative instruments. A decrease in the fair market value of the derivative instruments as the result of fluctuations in commodity prices and foreign exchange rates may result in a write-down of net assets and a non-cash charge against net income. Such write-downs and non-cash charges may be temporary in nature if the fair market value subsequently increases.

### **Certain Risks for United States Unitholders**

#### ***Limited Ability of Residents in the United States to Enforce Civil Remedies***

We are organized under the laws of Alberta, Canada and have our principal place of business in Canada. Most of our directors and all of our officers and the representatives of the experts who provide services to us (such as its auditors and its independent reserve engineers), and a substantial portion of our assets and all or a substantial portion of the assets of such persons are located outside the United States. As a result, it may be difficult for investors in the United States to effect service of process within the United States upon such directors, officers and representatives of experts who are not residents of the United States or to enforce against them judgements of the United States courts based upon civil liability under the United States federal securities laws or the securities laws of any state within the United States. There is doubt as to the enforceability in Canada against us or against any of our directors, officers or representatives of experts who are not residents of the United States, in original actions or in actions for enforcement of judgement of United States courts of liabilities based solely upon the United States federal securities laws or securities laws of any state within the United States.

#### ***Differences in Reporting Practices in Canada and the United States***

We report our production and reserve quantities in accordance with Canadian practices and specifically in accordance with NI 51-101. These practices are different from the practices used to report production and to estimate reserves in reports and other materials filed with the SEC by companies in the United States.

We incorporate additional information with respect to production and reserves which is either not generally included or prohibited under rules of the SEC and practices in the United States. We follow the Canadian practice of reporting gross production and reserve volumes; however, we also follow the United States practice of separately reporting these volumes on a net basis (after the deduction of royalties and similar payments). We also follow the Canadian practice of using forecast prices and costs when we estimate our reserves and we do not estimate our reserves using prices and costs held constant at the effective date of the reserve report.

We included in this Annual Information Form estimates of proved and proved plus probable reserves. The SEC generally prohibits the inclusion of estimates of probable reserves in filings made with it. This prohibition does not apply to us because we are a Canadian foreign private issuer.

### ***Additional Taxation Applicable to Non Residents***

The *Income Tax Act* (Canada) and the tax treaties between Canada and other countries may impose additional withholding or other taxes on the cash distributions or other property paid by us to Unitholders who are Non Residents of Canada, and these taxes may change from time to time. Since January 1, 2005, a 15% Canadian withholding tax is applied to return of capital portion of distributions made to Non Resident Unitholders.

Additionally, the reduced "Qualified Dividend" rate of 15% tax applied to our distributions under current U.S. tax laws is scheduled to expire at the end of 2010 and there is no assurance that this reduced tax rate will be renewed by the U.S. government at such time.

Furthermore, it is anticipated that the implementation of the SIFT Tax may have tax consequences for Non Residents of Canada that are more adverse than the tax consequences to other classes of Unitholders.

### ***Foreign Exchange Risk of Non Resident Unitholders***

Our distributions are declared in Canadian dollars and converted to foreign denominated currencies at the spot exchange rate at the time of payment. As a consequence, investors are subject to foreign exchange risk. To the extent that the Canadian dollar weakens with respect to their currency, the amount of the distribution will be reduced when converted to their home currency.

## **STABILITY RATING**

DBRS has assigned a stability rating of STA-5 (middle) to the Trust Units. The stability rating is based on a rating scale developed by DBRS that provides an indication of both the stability and sustainability of an income fund's distributions per unit. Ratings categories range from STA-1 to STA-7, with STA-1 being the highest. DBRS further separates the ratings into high, middle and low to indicate where within the ratings category they fall. Ratings take into consideration the seven main factors of: (1) operating and industry characteristics; (2) asset quality; (3) financial flexibility; (4) diversification; (5) size and market position; (6) sponsorship/governance; and (7) growth. In addition, consideration is given to specific structural or contractual elements that may eliminate or mitigate risks or other potentially negative factors.

Specifically, income funds rated as STA-5 are considered by DBRS to have weak distribution per unit stability and sustainability. An income fund rated as STA-5 is subject to many of the same cyclical, seasonal, commodity price and economic factors as the higher STA-4 rating category, but the lack of diversification is generally more pronounced, in addition such income funds will tend to be below average in several areas.

A rating is not a recommendation to buy, sell or hold any security and may be subject to revision or withdrawal at any time by DBRS.

## **MATERIAL CONTRACTS**

Except for contracts entered into in the ordinary course of business, the only material contracts entered into by us within the most recently completed financial year, or before the most recently completed financial year but are still material and are still in effect, are the following:

- (a) the Trust Indenture;
- (b) the Exchangeable Share provisions and the support agreement and the voting and exchange agreement;
- (c) the note indenture creating the Notes;
- (d) the trust indenture creating the 7.5% Convertible Debentures;

- (e) the supplemental indenture creating the 6.75% Convertible Debentures;
- (f) the trust unit rights incentive plan;
- (g) the restricted trust unit award plan; and
- (h) the credit agreement in respect of our one billion syndicated credit facility, which agreement is described in Note 7 to our consolidated financial statements for the year ended December 31, 2007, which note is incorporated by reference herein.

Copies of each of these documents have been filed on SEDAR at [www.sedar.com](http://www.sedar.com).

### **LEGAL PROCEEDINGS AND REGULATORY ACTIONS**

There are no legal proceedings that we are or was a party to, or that any of our property is or was the subject of, during the most recently completed financial year, that were or are material to us, and there are no such material legal proceedings that we are currently aware of that are contemplated.

There were no: (i) penalties or sanctions imposed against us by a court relating to securities legislation or by a securities regulatory authority during our most recently completed financial year; (ii) other penalties or sanctions imposed by a court or regulatory body against us that would likely be considered important to a reasonable investor in making an investment decision; or (iii) settlement agreements we entered into with a court relating to securities legislation or with a securities regulatory authority during our most recently completed financial year.

### **TRANSFER AGENT AND REGISTRAR**

The transfer agent and registrar for the Trust Units, the 7.5% Convertible Debentures and 6.75% Convertible Debentures is Valiant Trust Company at its principal office in Calgary, Alberta and through its co-agent, BNY Trust Company of Canada, at its principal office in Toronto, Ontario.

### **INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS**

There were no material interests, direct or indirect, of any senior officers, directors of Bonavista Petroleum, nominees for director of Bonavista Petroleum, any Unitholder who beneficially owns, or controls or directs, directly or indirectly, more than 10% of the Trust Units or Exchangeable Shares or any known associate or affiliate of such persons in any transaction since our inception or in any proposed transaction which has materially affected or is reasonably expected to materially affect us or Bonavista Petroleum other than as disclosed herein or as otherwise publicly disclosed.

### **INTERESTS OF EXPERTS**

There is no person or company whose profession or business gives authority to a statement, report or valuation made by such person or company and who is 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 us during, or related to, our most recently completed financial year other than GLJ and Ryder Scott, our independent engineering evaluators, and KPMG LLP, our independent auditors.

None of the designated professionals of GLJ or Ryder Scott have any registered or beneficial interests, direct or indirect, in any of our securities or other property or of our associates or affiliates either at the time they prepared the report, valuation, statement or opinion prepared by it, at any time thereafter or to be received by them.

In addition, none of the aforementioned persons or companies, nor any director, officer or employee of any of the aforementioned persons or companies, is or is expected to be elected, appointed or employed as a director, officer or employee of Bonavista Petroleum or of any of our associate or affiliate entities, except for Grant A. Zawalsky, the

Corporate Secretary of Bonavista Petroleum, is a partner at Burnet, Duckworth & Palmer LLP, which law firm renders legal services to us.

#### **ADDITIONAL INFORMATION**

Additional information relating to us can be found on SEDAR at [www.sedar.com](http://www.sedar.com) and on our website at [www.bonavistaenergy.com](http://www.bonavistaenergy.com). Additional information, including directors' and officers' remuneration and indebtedness, principal holders of our securities and securities issued and authorized for issuance under our equity compensation plans are contained in our information circular – proxy statement dated March 14, 2007 and will be contained in our 2008 proxy materials relating to our annual unitholders meeting to be held on May 15, 2008. Additional financial information is contained in our consolidated financial statements for the year ended December 31, 2007 and the related management's discussion and analysis.

For additional copies of the Annual Information Form and the materials listed in the preceding paragraphs please contact:

Bonavista Energy Trust  
c/o Bonavista Petroleum Ltd.  
Suite 700, 311 – 6th Avenue S.W.  
Calgary, Alberta, T2P 3H2  
Tel: (403) 213-4300  
Fax: (403) 262-5184

## APPENDIX A

### REPORT OF MANAGEMENT AND DIRECTORS ON RESERVES DATA AND OTHER INFORMATION Form 51-101F3

Management of Bonavista Petroleum Ltd. ("**Bonavista Petroleum**"), on behalf of Bonavista Energy Trust (the "**Trust**") is responsible for the preparation and disclosure of information with respect to the Trust's oil and natural 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, 2007, estimated using forecast prices and costs.

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

The Reserves Committee of the Board of Directors of Bonavista Petroleum, on behalf of the Trust, has:

- (a) reviewed Bonavista Petroleum's procedures for providing information to the independent qualified reserves evaluator;
- (b) met with the independent qualified reserves evaluator to determine whether any restrictions affected the ability of the independent qualified reserves evaluator to report without reservation; and
- (c) reviewed the reserves data with management and the independent qualified reserves evaluator.

The Reserves Committee of the Board of Directors of Bonavista Petroleum, on behalf of the Trust, has reviewed Bonavista Petroleum's procedures for assembling and reporting other information associated with oil and natural gas activities and has reviewed that information with management. The Board of Directors has, on the recommendation of the Reserves Committee, approved

- (a) the content and filing with securities regulatory authorities of Form 51-101F2 containing reserves data and other oil and gas information;
- (b) the filing of Form 51-101F2 which is the report of the independent qualified reserves evaluator on the reserves data; and
- (c) the content and filing of this report.

Because the reserves data are based on judgments regarding future events, actual results will vary and the variations may be material. However, any variation should be consistent with the fact that reserves are categorized according to the probability of their recovery.

(signed) "*Keith A. MacPhail*"  
Keith A. MacPhail  
Chairman, President  
and Chief Executive Officer

(signed) "*Thomas J. Mullane*"  
Thomas J. Mullane  
Vice President, Engineering

(signed) "*Walter C. Yeates*"  
Walter C. Yeates  
Director, Chairman of Reserves Committee

(signed) "*Michael M. Kanovsky*"  
Michael M. Kanovsky  
Director, Member of Reserves Committee

March 11, 2008

**APPENDIX B  
GLJ PETROLEUM CONSULTANTS LTD.**

**REPORT ON RESERVES DATA BY INDEPENDENT QUALIFIED RESERVES EVALUATOR  
Form 51-101F2**

To the Board of Directors of Bonavista Petroleum Ltd. ("**Bonavista Petroleum**"), on behalf of Bonavista Energy Trust (the "**Trust**"):

1. We have evaluated the Trust's reserves data as at December 31, 2007. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2007, estimated using forecast prices and costs.
2. The reserves data are the responsibility of Bonavista Petroleum'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 Trust evaluated by us for the year ended December 31, 2007, and identifies the respective portions thereof that we have evaluated and reported on to the Board of Directors of Bonavista Petroleum:

<u>Independent Qualified Reserves Evaluator</u>	<u>Description and Preparation Date of Evaluation Report</u>	<u>Location of Reserves (County or Foreign Geographic Area)</u>	<u>Net Present Value of Future Net Revenue (before income taxes, 10% discount rate – \$000s)</u>			
			<u>Audited</u>	<u>Evaluated</u>	<u>Reviewed</u>	<u>Total</u>
GLJ Petroleum Consultants Ltd.	Corporate Summary February 26, 2008	Canada	-	\$1,885,122	\$614,470	\$2,499,952

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.
6. We have no responsibility to update our reports for events and circumstances occurring after their respective preparation dates.
7. Because the reserves data are based on judgments regarding future events, actual results will vary and the variations may be material. However, any variation should be consistent with the fact that reserves are categorized according to the probability of their recovery.

Executed as to our report referred to above:

GLJ Petroleum Consultants Ltd., Calgary, Alberta, Canada , March 10, 2008

(signed) "*John Stilling*"  
John Stilling, P. Eng.  
Vice President

**APPENDIX C  
RYDER SCOTT COMPANY**

**REPORT ON RESERVES DATA BY INDEPENDENT QUALIFIED RESERVES EVALUATOR  
Form 51-101F2**

To the Board of Directors of Bonavista Petroleum Ltd. Ltd. ("**Bonavista Petroleum**"), on behalf of Bonavista Energy Trust (the "**Trust**"):

1. We have evaluated the Trust's reserves data as at December 31, 2007. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2007, estimated using forecast prices and costs.
2. The reserves data are the responsibility of Bonavista Petroleum'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 Trust evaluated by us for the year ended December 31, 2007, and identifies the respective portions thereof that we have evaluated and reported on to the Board of Directors of Bonavista Petroleum:

<u>Independent Qualified Reserves Evaluator</u>	<u>Description and Preparation Date of Evaluation Report</u>	<u>Location of Reserves (County or Foreign Geographic Area)</u>	<u>Net Present Value of Future Net Revenue (before income taxes, 10% discount rate – \$000s)</u>			
			<u>Audited</u>	<u>Evaluated</u>	<u>Reviewed</u>	<u>Total</u>
Ryder Scott Company	March 4, 2008	Canada	-	\$637,793	-	\$637,793

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.
6. We have no responsibility to update our reports for events and circumstances occurring after their respective preparation dates.
7. Because the reserves data are based on judgments regarding future events, actual results will vary and the variations may be material. However, any variation should be consistent with the fact that reserves are categorized according to the probability of their recovery.

Executed as to our report referred to above:

Ryder Scott Company, Calgary, Alberta, Canada , March 4, 2008

(signed) "*Alan T. Frison*"  
Alan T. Frison, P. Eng.  
Vice President, Engineering

## APPENDIX D

### MANDATE & TERMS OF REFERENCE OF THE AUDIT COMMITTEE

#### *Role and Objective*

The Audit Committee (the "**Committee**") is a committee of the board of directors (the "**Board**") of Bonavista Petroleum Ltd. (the "**Corporation**") to which the Board has delegated its responsibility for oversight of the nature and scope of the annual audit, management's reporting on internal accounting standards and practices, financial information and accounting systems and procedures, financial reporting and statements and recommending, for Board approval, the audited financial statements and other mandatory disclosure releases containing financial information and review the Report of the Reserve Committee of the annual reserves. The objectives of the Committee, with respect to the Corporation, the other subsidiaries, partnerships, trusts and other controlled entities of Bonavista Energy Trust and Bonavista Energy Trust to the extent delegated to the Corporation under the Trust Indenture (collectively, "**Bonavista**"), are as follows:

- To assist directors meet their responsibilities (especially for accountability) in respect of the preparation and disclosure of the financial statements of Bonavista and related matters;
- To provide better communication between directors and external auditors;
- To enhance the external auditor's independence;
- To increase the credibility and objectivity of financial reports; and
- 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*

- The Committee shall be comprised of at least 3 directors of the Corporation, all of whom are "independent" (as such term is used in Multilateral Instrument 52-110 – Audit Committee ("**MI 52-110**").
- The Board shall have the power to appoint the Committee Chairman and other members of the committee.
- All of the members of the Committee shall be "financially literate". The Board has adopted the definition for "financial literacy" used in MI 52-110.

#### *Meetings*

- At all meetings of the Committee every question shall be decided by a majority of the votes cast. In case of an equality of votes, the Chairman of the meeting shall not be entitled to a second or casting vote.
- A quorum for meetings of the Committee shall be a majority of its members, and the rules for calling, holding, conducting and adjourning meetings of the Committee shall be the same as those governing 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 shall be taken. The Chief Financial Officer shall attend meetings of the Committee, unless otherwise excused from all or part of any such meeting by the Chairman.
- The Committee shall forthwith report the results of meetings and reviews undertaken and any associated recommendations to the Board.

- The Committee shall 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 audit Committee consider appropriate.

### ***Mandate and Responsibilities of Committee***

- It is the responsibility of the Committee to oversee the work of the external auditors, including resolution of disagreements between management and the external auditors regarding financial reporting.
- It is the responsibility of the Committee to satisfy itself on behalf of the Board with respect to Bonavista's Internal Control Systems:
  - (a) identifying, monitoring and mitigating business risks; and
  - (b) ensuring compliance with legal, ethical and regulatory requirements including the certification process.
- It is a primary responsibility of the Committee to review the annual financial statements of Bonavista prior to their submission to the Board for approval. The process should include but not be limited to:
  - (a) review the appropriateness of significant accounting principles and any changes in accounting principles, or in their application, which may have a material impact on the current or future years' quarterly unaudited and annual audited financial statements;
  - (b) reviewing significant accruals, reserves or other estimates such as the ceiling test calculation;
  - (c) reviewing accounting treatment of unusual or non-recurring transactions;
  - (d) reviewing Bonavista Energy Trust's status as a "mutual fund trust" under the *Income Tax Act* (Canada);
  - (e) ascertaining compliance with covenants under loan agreements and Trust Indenture;
  - (f) reviewing adequacy of the asset retirement obligation in the financial statements;
  - (g) reviewing disclosure requirements for commitments and contingencies;
  - (h) reviewing adjustments raised by the external auditors, whether or not included in the financial statements;
  - (i) reviewing unresolved differences between management and the external auditors;
  - (j) reviewing non-recurring transactions;
  - (k) reviewing related party transactions; and
  - (l) obtain explanations of significant variances with comparative reporting periods.
- The Committee is to review the financial statements, prospectuses, management discussion and analysis (MD&A), annual information forms (AIF) and all public disclosure containing audited or unaudited financial information before release and prior to Board approval. The Committee must be satisfied that adequate procedures are in place for the review of Bonavista's disclosure of all other financial information and shall periodically access the accuracy of those procedures.
- With respect to the appointment of external auditors by the Board, the Committee shall:
  - (a) recommend to the Board the appointment of external auditors;

- (b) recommend to the Board the terms of engagement of the external auditor, including the compensation of the auditors and confirmation that the external auditors shall report directly to the Committee;
  - (c) 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
  - (d) review and approve any non-audit services to be provided by the external auditors' firm and consider the impact on the independence of the auditors.
- Review with external auditors (and internal auditor if one is appointed by Bonavista) their assessment of the internal controls of Bonavista, their written reports containing recommendations for improvement, and management's response and follow-up to any identified weaknesses. The Committee shall 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 Bonavista and its subsidiaries.
  - The Committee must pre-approve all non-audit services to be provided to Bonavista or its subsidiaries by the external auditors. The Committee may delegate to one or more members the authority to pre-approve non-audit services, provided that the member report to the Committee at the next scheduled meeting such pre-approval and the member comply with such other procedures as may be established by the Committee from time to time.
  - The Committee shall review risk management policies and procedures of Bonavista (i.e. hedging, litigation and insurance).
  - The Committee shall establish a procedure for:
    - (a) the receipt, retention and treatment of complaints received by Bonavista regarding accounting, internal accounting controls or auditing matters; and
    - (b) the confidential, anonymous submission by employees of Bonavista of concerns regarding questionable accounting or auditing matters.
  - The Committee shall have the authority to investigate any financial activity of Bonavista. All employees of Bonavista are to cooperate as requested by the Committee.
  - The Committee may retain persons having special expertise and/or obtain independent professional advise to assist in filling their responsibilities at the expense of Bonavista without any further approval of the Board.
  - The Committee shall meet periodically with the external auditors, independent of management. The issues for consideration should include, but are not limited to:
    - (a) obtain feedback on competencies, skill sets and performance of key members of the financial reporting team;
    - (b) enquire as to significant differences from prior year period audits or reviews;
    - (c) enquire as to transactions accounted for in an acceptable manner but not a basis which, in the opinion of the external auditor, was not the preferable accounting treatment;
    - (d) enquire as to any differences between management and the external auditor;
    - (e) enquire as to material differences in accounting policies, disclosures or presentation from prior periods;

- (f) enquire as to deficiencies in internal controls identified in the course of the performance of the procedures by the external auditors; and
- (g) enquire as to any other matters or observations that the external auditors would like to bring to the attention of the committee.