



## **Annual Information Form**

**Year Ended December 31, 2005**

**March 16, 2006**

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## ABBREVIATIONS

### Oil and Natural Gas Liquids

Bbl	barrel
Bbls	barrels
Mbbls	thousand barrels
Mmbbls	million barrels
Mstb	1,000 stock tank barrels
Bbls/d	barrels per day
BOPD	barrels of oil per day
NGLs	natural gas liquids
STB	standard tank barrels

### Natural Gas

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

### Other

AECO	EnCana Corp.'s natural gas storage facility located at Suffield, Alberta
API	American Petroleum Institute
°API	an indication of the specific gravity of crude oil measured on the API gravity scale. Liquid petroleum with a specified gravity of 28° API or higher is generally referred to as light crude oil
ARTC	Alberta Royalty Tax Credit
BOE	barrel of oil equivalent of natural gas and crude oil on the basis of 1 BOE for 6 Mcf of natural gas (this conversion factor is an industry accepted norm and is not based on either energy content or current prices)
BOE/d	barrel of oil equivalent per day
mt	megatonnes
m <sup>3</sup>	cubic metres
MBOE	1,000 barrels of oil equivalent
Mstboe	1,000 stock tank barrels of oil equivalent
M\$	thousands of dollars
MM\$	millions of dollars
WTI	West Texas Intermediate, the reference price paid in U.S. dollars at Cushing, Oklahoma for crude oil of standard grade

## CONVERSIONS

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

## 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 the Corporation's 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", "plan", "continue", "estimate", "expect", "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. The Corporation believes that 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, as the case may be. The Corporation does not intend, and does not assume any obligation, to update these forward-looking statements.

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

- the quantity of reserves;
- oil and natural gas production levels;
- capital expenditure programs;
- projections of market prices and costs;
- supply and demand for oil and natural gas;
- expectations regarding the Corporation's ability to raise capital and to continually add to reserves through acquisitions and development; and
- treatment under government regulatory and taxation regimes.

The Corporation's 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 and risks inherent in oil and natural gas operations;
- uncertainties associated with estimating reserves;
- competition for, among other things, capital, acquisitions of reserves, undeveloped lands and skilled personnel;
- incorrect assessments of the value of acquisition; and
- geological, technical, drilling and processing problems.

## CERTAIN DEFINITIONS

In this Annual Information Form, the following words and phrases have the following meanings, unless the context otherwise requires:

"**COGE Handbook**" means the Canadian Oil and Gas Evaluation Handbook prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum;

"**GLJ**" means GLJ Petroleum Consultants Ltd.;

"**GLJ Report**" means the report of GLJ dated March 16, 2006 evaluating the crude oil, natural gas liquids and natural gas reserves of the Corporation as at December 31, 2005;

"**Gross**" or "**gross**" means:

- (a) in relation to the Corporation's interest in production and reserves, its "Corporation gross reserves", which are the Corporation's interest (operating and non-operating) share before deduction of royalties and without including any royalty interest of the Corporation;
- (b) in relation to wells, the total number of wells in which the Corporation has an interest; and
- (c) in relation to properties, the total area of properties in which the Corporation has an interest; and

"**Net**" or "**net**" means:

- (d) in relation to the Corporation's interest in production and reserves, the Corporation's interest (operating and non-operating) share after deduction of royalties obligations, plus the Corporation's royalty interest in production or reserves;
- (e) in relation to wells, the number of wells obtained by aggregating the Corporation's working interest in each of its gross wells; and
- (f) in relation to the Corporation's interest in a property, the total area in which the Corporation has an interest multiplied by the working interest owned by the Corporation;

"**NI 51-101**" means National Instrument 51-101 Standards of Disclosure for Oil and Gas Activities;

**Certain other terms used herein but not defined herein are defined in NI 51-101 and, unless the context otherwise requires, shall have the same meanings herein as in NI 51-101.**

## ROCK ENERGY INC.

### The Corporation

Rock Energy Inc. (the "Corporation" or "Rock"), formerly Medbroadcast Corporation ("Medbroadcast"), changed its name to Rock Energy Inc. effective February 18, 2004 in conjunction with a continuation of Medbroadcast from the federal jurisdiction of Canada to the jurisdiction of the province of Alberta.

Medbroadcast was incorporated pursuant to the *Company Act* (British Columbia) on February 15, 1988 under the name "Prime Equities Inc.". On October 25, 1991, Medbroadcast's Memorandum was amended to change the name of Medbroadcast to "Prime Equities International Corporation", to consolidate its common shares on a 1:10 basis, and to increase the authorized capital back up to 700,000,000 shares divided into 400,000,000 common shares without par value and 300,000,000 preference shares ("Preference Shares") without par value. On August 11, 1998, the Corporation's Memorandum was amended to change the name of the Corporation to "medEra Life Science Corporation". On January 4, 2000, the Corporation continued into the federal jurisdiction of Canada pursuant to the *Canada Business Corporations Act*. Concurrent with such continuation, the Corporation changed its name to "Medbroadcast Corporation" and revised its authorized capital to consist of an unlimited number of common shares and 300,000 preference shares. In conjunction with such continuation, Medbroadcast adopted By-laws in place of the Articles.

On February 18, 2004 Medbroadcast was continued out of the federal jurisdiction of Canada into the Province of Alberta, the name of the Corporation was changed to "Rock Energy Inc." and the common shares of the Corporation were consolidated on a 1:30 basis.

The Corporation is a public energy company engaged in the exploration for and development and production of crude oil and natural gas, primarily in Western Canada.

The Corporation's head office is located at Suite 1800, 700 – 9th Avenue S.W., Calgary, Alberta, T2P 3V4 and its registered office is located at Suite 1400, 350 – 7th Avenue S.W., Calgary, Alberta, T2P 3N9.

### Corporate Strategy

Rock's corporate strategy is to grow and develop an oil and gas exploration and production company through internal operations and acquisitions. Rock's current geographic focus is east central Alberta and west central Saskatchewan (which comprises the Corporation's Plains core area) and the deep basin of western Alberta (which comprises the Corporation's West Central core area), although other opportunities have been and will be considered. As Rock grows, the Corporation intends to expand operations in the West Central core area as well as develop a third core area.

Rock intends to evaluate acquisitions, both properties and corporate, primarily in its target core areas to compliment future internal operations. Rock will continue to evaluate other acquisition opportunities over time, as the company continues to grow and execute its business plan.

### Subsidiaries

Rock has one active wholly-owned subsidiary, Rock Energy Ltd. ("Rock Energy"). Rock Energy was incorporated on November 21, 2002 under the *Business Corporations Act* (Alberta) as 1018369 Alberta Ltd. and as a wholly owned subsidiary of Storm Energy Ltd. ("Storm"). 1018369 Alberta Ltd. changed its name to Rock Energy Ltd. on December 10, 2002. On December 23, 2002 the Corporation bought the Medicine River property for 1,999,900 common shares of Rock Energy. Rock Energy began accounting for the property effective January 1, 2003. On January 14, 2003 Rock acquired 1018260 Alberta Ltd. ("1018260") by issuing 2,210,000 common shares of Rock Energy ("Rock Energy Shares") for all of the outstanding shares of 1018260. 1018260 was a corporation controlled by the Bey Family Trust, Alexander Brown, Sean Moore and Storm. After the acquisition, the shareholders of 1018260 (excluding Storm) owned 52% of the Rock Energy Shares. Rock Energy and 1018260 amalgamated effective January 15, 2003, and the amalgamated company continued under the name "Rock Energy Ltd."

All of the Rock Energy oil and gas properties are now beneficially owned by the Rock Energy Production Partnership (the "Partnership"). The partners of the Partnership are the Corporation and Rock Energy. Legal title to the oil and gas properties is held by Rock Energy.

On April 7, 2005 the Corporation purchased certain oil and gas properties as well as all of the shares of 1143734 Alberta Ltd. and on June 17, 2005 the Corporation purchased all of the shares of 1140511 Alberta Ltd., 1156168 Alberta Ltd. and 1159120 Alberta Ltd., all as a result of the acquisitions announced on March 14, 2005. All of the properties which were directly and indirectly acquired were contributed to the Partnership and the companies purchased were wound up into the Corporation effective June 30, 2005. Following this reorganization the only active subsidiary of the Corporation is Rock Energy.

**Unless the context otherwise requires, reference in this Annual Information Form to the "Corporation" includes the Corporation, Rock Energy and the Partnership.**

### DESCRIPTION OF CAPITAL STRUCTURE

As a result of the amendments described above (see "Rock Energy Inc. - The Corporation" section), the authorized share capital of the Corporation consists of an unlimited number of common shares without nominal or par value and 300,000 preferred shares. The following is a description of the rights, privileges, instructions and conditions attached to the authorized share capital of the Corporation.

#### Common Shares

The holders of common shares are entitled to one vote at each meeting of holders of common shares. On the liquidation, dissolution or winding-up of the Corporation, or any other distribution of the assets of the Corporation among its shareholders for the purpose of winding-up its affairs, the holders of the common shares shall be entitled to receive the remaining property and assets of the Corporation. The holders of common shares are entitled to receive, if, as and when declared by the directors of the Corporation, non-cumulative dividends at such rate and payable on such date as may be determined from time to time by the directors of the Corporation.

#### Preferred Shares

The preferred shares may at any time and from time to time be issued in one or more series, each series to consist of such number of shares, subject to the maximum total number of preferred shares issuable, as may, before the issue thereof, be determined by resolution of the board of directors of the Corporation. Subject to the provisions of the *Business Corporation Act* (Act), the board of directors of the Corporation may by resolution fix from time to time before the issue thereof the designation, rights, privileges, restrictions and conditions attached to each series of the preferred shares

The following sets forth information in respect of securities authorized for issuance under the Corporation's equity compensation plan as at December 31, 2005.

<b>Plan Category</b>	<b>Number of securities to be issued upon exercise of outstanding options, warrants and rights (a)</b>	<b>Weighted average exercise price of outstanding options, warrants and rights (b)</b>	<b>Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a)) (c)</b>
Equity compensation plans approved by securityholders	1,120,332	\$4.51	843,400 <sup>(1)</sup>
Equity compensation plans not approved by securityholders	-	-	-
Total	1,120,332	\$4.51	843,400 <sup>(1)</sup>

Note:

- (1) The Corporation's stock option plan currently provides for the grant of a maximum number of Common Shares equal to 10% of the outstanding common shares.

## GENERAL DEVELOPMENT OF THE BUSINESS

Prior to 2004 Medbroadcast was involved in the businesses of developing and distributing online medical and health information via its website [www.medbroadcast.com](http://www.medbroadcast.com) and in investigating and developing additional complementary business opportunities within the health field and, prior thereto, in the business of providing administrative, exploration and other management and consulting services to various resource companies including companies in which it may have an equity interest.

During the year ended 2001, Medbroadcast continued the development and operation of its medical information website, [medbroadcast.com](http://medbroadcast.com). Medbroadcast completed equity financings during the fiscal year for cash proceeds totalling \$5,386,451 and also issued shares for advertising services totalling \$4,980,572. These included investments received from CanWest Global Communications Corp. ("Global") totalling \$10 million (\$5.0 million in cash and \$5.0 million in advertising services) and other financings totalling \$529,580. Medbroadcast was a co-applicant with Global in an application to establish a new, digital specialty health television broadcast service, which was denied by the CRTC on November 24, 2000. CyberActive Technology continued development activities funded by the Corporation. Medbroadcast discontinued its HealthMart.ca in November of 2000 due to low utilization. There were no material exploration activities during the year and Medbroadcast continued its plan of divesting of its investment holdings in junior resource companies. The financial results for the year ended March 31, 2001 included revenues of \$238,629 and an operating loss of \$8,726,391. Development expenses for [medbroadcast.com](http://medbroadcast.com) contributed to the loss.

During the year ended 2002, Medbroadcast continued the development and operation of [medbroadcast.com](http://medbroadcast.com). Medbroadcast completed equity financings during the fiscal year for gross proceeds of \$500,000. Medbroadcast began to leverage its investment in the website with revenues of \$250,360 generated from the sale of advertising, sponsored content and related services. Subsequent to year-end, Medbroadcast transferred its CyberPatient Technology license to UBC and Dr. Karim Qayumi, retaining an interest in the resulting company, thereby relieving itself of any funding obligations. The financial results for the year ended March 31, 2002 included revenues of \$250,360 and an operating loss of \$4,113,625. The use of advertising credits contributed over \$2.5 million to the loss.

In 2003 Medbroadcast continued to improve its financial performance by reducing annual expenses from \$4.5 million in 2002 to \$766,405 in 2003 and by increasing revenue from \$250,360 in 2002 to \$272,216 in 2003 resulting in an operating loss of less than \$500,000 compared to over \$4.1 million in 2002. Despite this, and as announced in Medbroadcast's 2002 AGM material, Medbroadcast's primary focus for 2003 had been the identification, investigation and combination with an enterprise which will enhance the long term prospects for shareholder return.

On October 24, 2003, Medbroadcast issued 132,860,939 special common share purchase warrants of Medbroadcast ("Special Warrants") at a price of \$0.1129 per Special Warrant for gross proceeds of \$15,000,000, each of which Special Warrants entitled the holder to acquire 1 common share of Medbroadcast for no additional consideration, subject to adjustment in certain events (the "Financing"). At closing the gross proceeds of \$15,000,000 were deposited in escrow with Computershare Trust Company of Canada pursuant to the terms of a special warrant indenture dated October 23, 2003 between Medbroadcast and Computershare Trust Company of Canada (the "Special Warrant Indenture") and in accordance with the terms of the Special Warrant Indenture, the escrowed funds were not to be released from escrow until the later of the date that shareholders of Medbroadcast approved the financing and the date that Allen J. Bey was appointed as President and Chief Executive Officer of Medbroadcast.

On October 31, 2003, Medbroadcast entered into a pre-acquisition agreement with Rock Energy (the "Pre-Acquisition Agreement") wherein Medbroadcast agreed, subject to the terms and conditions of the Pre-Acquisition Agreement, including obtaining shareholder approval of the acquisition to make an offer (the "Offer") to purchase all of the outstanding common shares of Rock Energy (including any common shares of Rock Energy which may become outstanding pursuant to the exercise of outstanding warrants to acquire common shares of Rock Energy) for an ascribed price of \$2.70 for each common share of Rock Energy to be comprised of 23.92 common shares of Medbroadcast for each common share of Rock Energy.

At a special meeting of shareholders of Medbroadcast held on January 6, 2004, the shareholders of Medbroadcast approved a number of matters including the Financing and the licensing of Medbroadcast's website to Virtual Learning Inc. (the "VLI Transaction"). Following the shareholder meeting on January 6, 2004, a new management team for Medbroadcast was appointed consisting of Allen J. Bey as President and Chief Executive Officer, Peter D. Scott as Vice-President,

Finance and Chief Financial Officer, Alexander (Sandy) C. Brown as Vice-President, Exploration, Sean E. Moore as Vice-President, Production and Grant Zawalsky as Corporate Secretary. As a result of the foregoing, the gross proceeds of \$15,000,000 which were held in escrow pursuant to the Special Warrant Indenture were released from escrow.

At a special meeting of shareholders of Medbroadcast held on January 7, 2004, the shareholders of Medbroadcast approved a number of matters including the making by Medbroadcast of the Offer to purchase all the issued and outstanding common shares of Rock Energy in accordance with the Pre-Acquisition Agreement, the consolidation of the outstanding common shares of Medbroadcast on a 30 for 1 basis (including the shareholders of Medbroadcast who hold less than 1,001 common shares prior to the consolidation and, accordingly, who would receive less than 34 common shares as a result of the consolidation will not receive post-consolidation common shares, provided that such shareholders shall instead receive cash payment in the amount of \$0.1129 for each common share held prior to giving effect to the consolidation), the change of name of Medbroadcast to "Rock Energy Inc." and the continuance of Medbroadcast from the federal jurisdiction of Canada to the province of Alberta.

On January 7, 2004, Medbroadcast delivered the Offer to the holders of common shares of Rock Energy resulting in the acquisition by Medbroadcast on January 8, 2004 of all of the outstanding common shares of Rock Energy in exchange for the issuance by Medbroadcast of 116,251,201 of its pre-consolidation common shares. Also on January 8, 2004, the board of directors of Medbroadcast was reconstituted through the resignations of all existing Medbroadcast directors other than Leanne Bate and Allen J. Bey and the appointment of Stuart G. Clark and Peter Malowany as directors.

Immediately following completion of the Offer, former shareholders of Medbroadcast held approximately 7.8% of the outstanding common shares of the Corporation, former holders of Special Warrants held approximately 49.2% of the outstanding common shares of the Corporation and former shareholders of Rock Energy held approximately 43.0% of the outstanding common shares of the Corporation.

On February 18, 2004 Medbroadcast was continued out of the federal jurisdiction of Canada into the Province of Alberta, the name of the Corporation was changed to "Rock Energy Inc." and the common shares of the Corporation were consolidated on a 1:30 basis.

On July 21, 2004, the common shares of the Corporation were listed on the Toronto Stock Exchange. Concurrent with such listing the common shares of the Corporation were delisted from the TSX Venture Exchange.

On September 22, 2004 MediResource Inc. (formerly Virtual Learning Inc.) exercised its option to purchase the licensed assets under the VLI Transaction and such purchase was closed on September 30, 2004.

In 2005 the Corporation completed a series of acquisitions of a number of oil and natural gas properties located in Western Canada (collectively, the "Properties") from six private companies and eight drilling fund limited partnerships and their respective general partners (collectively, the "Vendors"). The transactions closed in stages on April 7, 2005 and June 17, 2005 for aggregate consideration of approximately \$60.6 million, after adjustments, consisting of 10,325,487 common shares of the Corporation and approximately \$23.2 million in cash (collectively, the "Acquisition"). The Properties represented non-operated working interests ranging from 5% to 85% in a number of different plays across the western Canadian sedimentary basin. ELM Energy Management Ltd. had managed the oil and gas investments on behalf of the Vendors which had common interests in many of the same properties. The average working interest based on reserve volumes was approximately 28%. The major Properties (comprising 75% of the value of the Properties) were located in:

- Wild River, Alberta (30% working interest);
- Northeast BC – Parkland, Cypress (12 – 45% working interest);
- Musreau, Alberta (7 – 20% working interest);
- Elmworth/Wapiti, Alberta (20 – 45% working interest);
- Girouxville, Alberta (45% working interest); and
- Niton, Alberta (45% working interest).

The acquisition also included approximately 20,000 net (72,000 gross) acres of undeveloped land along with seismic data.

## SIGNIFICANT ACQUISITIONS AND SIGNIFICANT DISPOSITIONS

There were no significant acquisitions or significant dispositions by the Corporation or any significant probable acquisition by the Corporation within or since the completion of the most recently completed financial year of the Corporation except for the purchase of the Properties from the Vendors (the "Acquisition") as described above under "General Development of the Business".

The Corporation filed a Form 51-102F4 dated August 19, 2005 in respect of the Acquisition (the "Business Acquisition Report") on SEDAR, which Business Acquisition Report is incorporated herein by this reference.

## RECENT DEVELOPMENTS

The Corporation recently engaged an advisor to assist it with an asset rationalization project to swap and/or sell a portion of its properties including some of the Properties acquired in the Acquisition (see "General Development of the Business"). This project has been initiated and results are expected to be announced prior to June 30, 2005. The Corporation could be a net seller of production as a result of this process.

## DESCRIPTION OF THE BUSINESS AND PRINCIPAL PROPERTIES

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

The Corporation spent capital of \$84.2 million for the year ended December 31, 2005 included \$60.6 million for the Acquisition, \$0.1 million for office equipment and \$23.5 million directed primarily to developing Rock's grass roots exploration and development operations in the Plains core area and continuing activity on the acquired Properties. Of the \$23.5 million noted above, 23% was spent on acquiring land (\$3.7 million) and seismic (\$1.7 million). Rock drilled 20 (20 net) wells in its Plains core area and 13 (2.4 net) wells on the acquired Properties (mostly in the West Central core area) in 2005, which accounted for 69% of spending or \$16.3 million. Of these wells, 14 (14.0 net) are successful heavy oil wells, 9 (2.1 net) are successful gas wells, 4 (1.1 net) are successful light oil wells and 6 (5.2 net) were dry. All of the successful heavy and light oil wells were completed and equipped in 2005. 5 (0.7 net) of the gas wells were brought on production during 2005 and the remaining 4 (1.4 net) wells are expected to be tied in during the first quarter of 2006. The Corporation also spent 4% (\$0.9 million) of the capital budget on facilities and well site equipment inventory primarily relating to pre-ordering oil tanks and engines in order to shorten equipping times post drilling. Rock capitalizes certain salary and related costs associated with exploration and development which accounted for 4% (\$0.9 million) of capital spending for the nine months ended December 31, 2004.

Rock's Board of Director's has approved a \$30 million capital budget for 2006 directed primarily at the Plains and West Central core areas. This budget contemplates drilling 35 to 40 wells for approximately \$21 million, acquiring land and seismic for \$7.5 million and capitalized costs of \$1.5 million. The majority of the drilling is likely expected to commence after spring break-up. The drilling program is on lands that are currently owned and are seismically supported and will be a mix of exploration and development wells targeting both oil and gas. Included in the drilling costs are the estimated cost of tie-ins and well site facilities required to bring production on stream. Under this program, new production is expected to come on stream two to three months after drilling has been completed. The budget is split almost equally between the Plains and West Central core areas. The majority of technical resources are expected to be directed towards the West Central core area in order to expand the Corporation's prospect list for this area. The Plains core area currently has approximately a two year inventory of drilling opportunities identified.

### Principal Properties

The following is a description of the Corporation's oil and natural gas properties as at December 31, 2005. Reserve amounts are stated, before the deduction of royalties and without including any royalty interests (i.e. gross reserves), as at December 31, 2005 based on forecasted costs and prices as evaluated in the GLJ Report (see "Reserves Data"). **The estimate of reserves and future net revenue for individual properties may not reflect the same confidence level as estimates of reserves and future net revenue for all properties, due to the effects of aggregation.** Unless otherwise specified, gross and net acres and well count information are as at December 31, 2005.

### ***Medicine River, Alberta***

Rock owns two sections of land (1,280 acres) in the Medicine River area of central Alberta. As of the date hereof, the property includes 6 (5.4 net) producing oil wells, 4 (2.0 net) producing gas wells and 1 (0.8 net) shut-in gas well. No disposal or injection wells are located on the property. Production is initially processed through Rock's 100% owned facility which is located on these lands. The facility processes the oil in order to meet pipeline specifications and is then trucked to a third party terminal for sale. The facility also meters and compresses Rock's operated natural gas production which is tied-in to a third party processing plant for ultimate sale. Rock operates all the production (except 2 (1.3 net) gas wells) and its facility through a contract operator. The natural gas production comes from the Edmonton, Cardium, Nordegg and Glauconite sands and the oil production comes from the Jurassic, Pekisko and Basal Quartz formations. Rock does not own rights to all the zones on these lands so other companies also have wells on these lands. In 2003 Rock drilled 1 (0.75 net) Edmonton gas well and recompleted 1 (0.7125 net) Jurassic oil well, both of which were tied-in in October 2003. In July 2004 a partner recompleted a Nordegg gas well (0.33 net), which Rock was equalized into in December 2004. In January 2005 Rock farmed out their interest in a shut-in well bore which was recompleted in the Glauconite formation for gas.

### ***Plains Core Area (east central Alberta and west central Saskatchewan)***

Rock owns 21,879 (21,335 net) acres of land in the Plains core area of east central Alberta and west central Saskatchewan, which consists of four property areas with the majority of production coming from the Lloydminster property in east central Alberta. As of the date hereof, the core area includes 18 (18.0 net) producing heavy oil wells, 2 (2.0 net) producing gas wells 1 (1.0 net) standing gas well and no shut-in wells or disposal wells. The heavy oil wells were drilled in 2004 and 2005 with most of the production coming on in late 2005. These wells are primarily producing from the Sparky formation. Production is processed at a 100% owned well site batteries and then trucked to a third party terminal for sale. The 2 (2.0 net) gas wells came on production early 2005 and January 2006 and produce from the McLaren, Rex and Colony formations. Gas production is tied into a 100% owned gathering lines which tie in to third party pipelines and processing facilities where the gas is sold.

### ***Wild River, Alberta***

The Corporation's interests in the Wild River area includes 1 (0.3 net) producing natural gas well producing from the Nisku formation and is non-operated. No disposal or injection wells are located on the property. Production is tied in through a gathering system (30% owned by the Corporation) to a third party gathering system and can be processed at several third party plants in the area. A 3/8" stainless steel injection string was installed in 2005 to keep elemental sulphur in solution and reduce operating costs. The Corporation owns 3,840 (1,088 net) undeveloped acres of land in the area.

### ***Northeast BC***

The Corporation's interests in northeast BC is comprised of 8 properties and includes 4 (2.1 net) producing natural gas wells, 10 (3.1 net) shut-in wells and no oil wells or disposal wells. Production in the area is all non-operated and comes from the Halfway, Belloy and Doig formations. Production is processed at third party facilities. The Corporation owns 19,234 (6,698 net) undeveloped acres in northeast BC. Drilling in the area is primarily winter access only and management expects activity levels to increase beginning with the 2006/07 season.

### ***Musreau, Alberta***

The Corporation's interests in the Musreau area includes 9 (1.0 net) producing natural gas wells, 1(0.1 net) natural gas well to be tied-in, 1 (0.1 net) shut-in wells and no producing oil or disposal wells. The gas wells were drilled in the second half of 2004 and in 2005 and produce from the Fahler and Cadomin formations. The wells are non-operated. Gas is gathered and processed at a third party plant in the area. The Corporation owns 7,360 (1,610 net) undeveloped acres of land in the area. Management expects additional drilling in 2006.

### ***Elmworth/Wapiti, Alberta***

The Corporation's interest in the Elmworth/Wapiti area includes 7 (1.8 net) natural gas wells and no oil wells, shut-in wells or disposal wells. Production comes from the Notikewin, Falher, Cadomin and Gething formations and is non-operated.

Production is processed at third party facilities. The Corporation owns 4,480 (1,168 net) undeveloped acres of land in the area.

***Niton, Alberta***

The Corporation's interest in the Niton area includes 4 (1.7 net) oil wells, 1 (0.4 net) natural gas wells and no shut-in wells or disposal wells. Oil production comes from the Rock Creek formation and gas production is from the Elerslie formation. Production is non-operated. Gas production is processed at third party facilities. The Corporation owns 2,883 (1,108 net) undeveloped acres in the area. Management expects that two to four oil wells will be drilled in this area in 2006.

## STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

The statement of reserves data and other oil and gas information set forth below (the "Statement") is dated March 16, 2006. The effective date of the Statement is December 31, 2005 and the preparation date of the Statement is February 9, 2006.

### Disclosure of Reserves Data

The reserves data set forth below (the "Reserves Data") is based upon an evaluation by GLJ with an effective date of December 31, 2005 contained in the GLJ Report. The Reserves Data summarizes the oil, liquids and natural gas reserves of the Corporation and the net present values of future net revenue for these reserves using constant prices and costs and forecast prices and costs. The GLJ Report has been prepared in accordance with the standards contained in the COGE Handbook and the reserve definitions contained in NI 51-101. Additional information not required by NI 51-101 has been presented to provide continuity and additional information which we believe is important to the readers of this information. The Company engaged GLJ to provide an evaluation of proved and proved plus probable reserves and no attempt was made to evaluate possible reserves. All of Rock's reserves are in Canada and, specifically, in the provinces of Alberta, British Columbia and Saskatchewan.

**Disclosure provided herein in respect of BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 Mcf:1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.**

**All evaluations and reviews of future net cash flow are stated prior to any provision for interest costs or general and administrative costs and after the deduction of estimated future capital expenditures for wells to which reserves have been assigned. It should not be assumed that the estimated future net cash flow shown below is representative of the fair market value of the Corporation's properties. There is no assurance that such price and cost assumptions will be attained and variances could be material. The recovery and reserve estimates of crude oil, NGLs and natural gas reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual crude oil, NGLs and natural gas reserves may be greater than or less than the estimates provided herein.**

### *Reserves Data (Constant Prices and Costs)*

SUMMARY OF OIL AND GAS RESERVES  
AND NET PRESENT VALUES OF FUTURE NET REVENUE  
as of December 31, 2005  
CONSTANT PRICES AND COSTS

RESERVES CATEGORY	RESERVES							
	LIGHT AND MEDIUM OIL		HEAVY OIL		NATURAL GAS		NATURAL GAS LIQUIDS	
	Gross (Mbbbl)	Net (Mbbbl)	Gross (Mbbbl)	Net (Mbbbl)	Gross (MMcf)	Net (MMcf)	Gross (Mbbbl)	Net (Mbbbl)
PROVED								
Producing	309	266	808	668	12,024	8,867	105	74
Non-Producing	27	25	0	0	1,182	941	7	5
Undeveloped	0	0	305	253	1,320	926	0	0
TOTAL PROVED	336	291	1,112	921	14,526	10,734	113	79
PROBABLE	99	88	968	797	5,201	3,938	36	25
TOTAL PROVED PLUS PROBABLE	435	379	2,081	1,718	19,727	14,672	149	104

## NET PRESENT VALUES OF FUTURE NET REVENUE

RESERVES CATEGORY	BEFORE INCOME TAXES DISCOUNTED AT (%/year)					AFTER INCOME TAXES DISCOUNTED AT (%/year)				
	0 (M\$)	5 (M\$)	10 (M\$)	15 (M\$)	20 (M\$)	0 (M\$)	5 (M\$)	10 (M\$)	15 (M\$)	20 (M\$)
PROVED										
Producing	91,689	77,154	67,156	59,848	54,252	82,801	70,198	61,531	55,185	50,312
Non-Producing	6,785	5,265	4,312	3,638	3,129	4,643	3,497	2,816	2,347	1,999
Undeveloped	5,785	4,444	3,440	2,676	2,085	3,841	2,794	2,035	1,472	1,046
TOTAL PROVED	104,260	86,863	74,909	66,162	59,466	91,284	76,489	66,382	59,004	53,357
PROBABLE	43,280	30,920	23,684	18,962	15,644	29,149	20,472	15,473	12,240	9,980
TOTAL PROVED PLUS PROBABLE	147,450	117,783	98,593	85,124	75,110	120,433	96,961	81,855	71,244	63,337

TOTAL FUTURE NET REVENUE  
(UNDISCOUNTED)  
as of December 31, 2005  
CONSTANT PRICES AND COSTS

RESERVES CATEGORY	REVENUE (M\$)	ROYALTIES (M\$)	OPERATING COSTS (M\$)	DEVELOPMENT COSTS (M\$)	WELL ABANDONMENT COSTS (M\$)	FUTURE NET REVENUE BEFORE INCOME TAXES (M\$)	INCOME TAXES (M\$)	FUTURE NET REVENUE AFTER INCOME TAXES (M\$)
Proved Producing Reserves	160,404	30,669	36,449	75	1,522	91,689	8,888	82,801
Proved Reserves	193,531	36,719	44,505	6,228	1,819	104,260	12,975	91,284
Proved Plus Probable Reserves	276,443	52,096	64,230	10,610	1,966	147,540	27,107	120,433

FUTURE NET REVENUE  
BY PRODUCTION GROUP  
as of December 31, 2005  
CONSTANT PRICES AND COSTS

RESERVES CATEGORY	PRODUCTION GROUP	FUTURE NET REVENUE BEFORE INCOME TAXES (discounted at 10%/year) (M\$)
Proved Producing Reserves	Light and Medium Crude Oil (including solution gas and other by-products)	10,407
	Heavy Crude Oil	7,677
	Natural Gas	49,073
	Other Company Revenue	0
Proved Reserves	Light and Medium Crude Oil (including solution gas and other by-products)	10,397
	Heavy Crude Oil	8,677
	Natural Gas	55,835
	Other Company Revenue	0
Proved Plus Probable Reserves	Light and Medium Crude Oil (including solution gas and other by-products)	11,397
	Heavy Crude Oil	15,160
	Natural Gas	72,036
	Other Company Revenue	0

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

SUMMARY OF OIL AND GAS RESERVES  
AND NET PRESENT VALUES OF FUTURE NET REVENUE  
as of December 31, 2005  
FORECAST PRICES AND COSTS

RESERVES CATEGORY	RESERVES							
	LIGHT AND MEDIUM OIL		HEAVY OIL		NATURAL GAS		NATURAL GAS LIQUIDS	
	Gross (Mbbbl)	Net (Mbbbl)	Gross (Mbbbl)	Net (Mbbbl)	Gross (MMcf)	Net (MMcf)	Gross (Mbbbl)	Net (Mbbbl)
PROVED								
Developed Producing	304	262	824	676	11,925	8,781	103	73
Developed Non-producing	27	25	0	0	1,182	941	7	5
Undeveloped	0	0	305	250	1,320	926	0	0
TOTAL PROVED	331	286	1,128	926	14,427	10,648	111	78
PROBABLE	96	85	986	786	5,230	3,960	35	25
TOTAL PROVED PLUS PROBABLE	427	371	2,096	1,712	19,657	14,608	146	102

## NET PRESENT VALUES OF FUTURE NET REVENUE

RESERVES CATEGORY	BEFORE INCOME TAXES DISCOUNTED AT (%/year)					AFTER INCOME TAXES DISCOUNTED AT (%/year)				
	0 (M\$)	5 (M\$)	10 (M\$)	15 (M\$)	20 (M\$)	0 (M\$)	5 (M\$)	10 (M\$)	15 (M\$)	20 (M\$)
PROVED										
Developed Producing	77,452	67,654	60,571	55,182	50,918	72,965	63,796	57,214	52,230	48,300
Developed Non- producing	4,968	3,960	3,315	2,849	2,490	3,414	2,590	2,091	1,746	1,488
Undeveloped	4,034	3,137	2,459	1,936	1,527	2,566	1,851	1,330	941	646
TOTAL PROVED	86,454	74,751	66,344	59,967	54,935	78,945	68,236	60,635	54,918	50,434
PROBABLE	35,495	26,506	20,971	17,224	14,514	24,173	17,657	13,735	11,120	9,249
TOTAL PROVED PLUS PROBABLE	121,950	101,256	87,315	77,191	69,449	103,118	85,893	74,370	66,038	59,683

TOTAL FUTURE NET REVENUE  
(UNDISCOUNTED)  
as of December 31, 2005  
FORECAST PRICES AND COSTS

RESERVES CATEGORY	REVENUE (M\$)	ROYALTIES (M\$)	OPERATING COSTS (M\$)	DEVELOPMENT COSTS (M\$)	WELL ABANDONMENT COSTS (M\$)	FUTURE NET REVENUE BEFORE INCOME TAXES (M\$)	INCOME TAXES (M\$)	FUTURE NET REVENUE AFTER INCOME TAXES (M\$)
Proved Producing Reserves	146,079	27,539	39,206	75	1,806	77,452	4,487	72,965
Proved Reserves	175,601	32,520	48,076	6,383	2,167	86,454	7,509	78,945
Proved Plus Probable Reserves	252,769	46,452	71,079	10,767	2,491	121,950	18,832	103,118

FUTURE NET REVENUE  
BY PRODUCTION GROUP  
as of December 31, 2005  
FORECAST PRICES AND COSTS

RESERVES CATEGORY	PRODUCTION GROUP	FUTURE NET REVENUE BEFORE INCOME TAXES (discounted at 10%/year) (M\$)
Proved Producing Reserves	Light and Medium Crude Oil (including solution gas and other by-products)	8,122
	Heavy Oil	9,870
	Natural Gas	42,580
	Other Company Revenue	0
Proved Reserves	Light and Medium Crude Oil (including solution gas and other by-products)	8,128
	Heavy Oil	11,503
	Natural Gas	46,714
	Other Company Revenue	0
Proved Plus Probable Reserves	Light and Medium Crude Oil (including solution gas and other by-products)	8,867
	Heavy Oil	19,884
	Natural Gas	58,564
	Other Company Revenue	0

**Notes to Reserves Data Tables:**

1. Columns may not add due to rounding.
2. The crude oil, natural gas liquids and natural gas reserve estimates presented in the GLJ Report are based on the definitions and guidelines contained in the COGE Handbook. A summary of those definitions are set forth below.

***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

- analysis of drilling, geological, geophysical and engineering data;
- the use of established technology; and
- specified economic conditions.

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.

Other criteria that must also be met for the categorization of reserves are provided in the COGE Handbook.

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

- (c) **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.
- (d) **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.

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.

Additional clarification of certainty levels associated with reserves estimates and the effect of aggregation is provided in the COGE Handbook.

### **3. Forecast Prices and Costs**

The forecast cost and price assumptions assume increases in wellhead selling prices and take into account inflation with respect to future operating and capital costs. Crude oil and natural gas benchmark reference pricing, as at December 31, 2005, inflation and exchange rates utilized by GLJ in the GLJ Report, which were GLJ's then current forecasts at the date of the GLJ Report, were as follows:

SUMMARY OF PRICING AND INFLATION RATE ASSUMPTIONS  
as of December 31, 2005  
FORECAST PRICES AND COSTS

Year	OIL				NATURAL GAS	NATURAL GAS LIQUIDS				INFLATION RATES <sup>(1)</sup> %/Year	EXCHANGE RATE <sup>(2)</sup> (\$US/\$Cdn)
	WTI Cushing Oklahoma (\$US/Bbl)	Edmonton Par Price 40° API (\$Cdn/Bbl)	Medium Crude 29° API (\$Cdn/Bbl)	Hardisty Heavy Crude 12° API (\$Cdn/Bbl)	AECO Gas Price (\$Cdn/Mmbtu)	Edmonton Pentanes Plus (\$Cdn/Bbl)	Edmonton Propane (\$Cdn/Bbl)	Edmonton Butane (\$Cdn/Bbl)	Spec Ethane (\$Cdn/Bbl)		
Forecast											
2006	57.00	66.25	55.75	33.25	10.60	67.00	42.50	49.00	36.00	2	0.85
2007	55.00	64.00	55.25	32.75	9.25	65.25	41.00	47.25	31.25	2	0.85
2008	51.00	59.25	51.25	32.50	8.00	60.50	38.00	43.75	27.00	2	0.85
2009	48.00	55.75	48.25	32.00	7.50	56.75	35.75	41.25	25.25	2	0.85
2010	46.50	54.00	46.75	32.00	7.20	55.00	34.50	40.00	24.25	2	0.85
2011	45.00	52.25	45.25	33.50	6.90	53.25	33.50	38.75	23.25	2	0.85
2012	45.00	52.25	45.25	33.50	6.90	53.25	33.50	38.75	23.25	2	0.85
2013	46.00	53.25	46.00	34.00	7.05	54.25	34.00	39.50	23.75	2	0.85
2014	46.75	54.25	47.00	34.75	7.20	55.25	34.75	40.25	24.25	2	0.85
2015	47.75	55.50	48.00	35.25	7.40	56.50	35.50	41.00	25.00	2	0.85
2016	48.75	56.50	48.75	36.00	7.55	57.75	36.25	41.75	25.50	2	0.85
Thereafter	+2%/year	+2%/year	+2%/year	+2%/year	+2%/year	+2%/year	+2%/year	+2%/year	+2%/year	+2%/year	0.85

## Notes:

- (1) Inflation rates for forecasting prices and costs.
- (2) Exchange rates used to generate the benchmark reference prices in this table.

Weighted average historical prices realized by the Corporation for the year ended December 31, 2005, were \$10.22/Mcf for natural gas, \$64.95/Bbl for light and medium crude oil, \$27.44/Bbl for heavy crude oil and \$56.19/Bbl for natural gas liquids.

#### 4. Constant Prices and Costs

The constant crude oil and natural gas benchmark references pricing and the exchange rate utilized in the GLJ Report were as follows:

SUMMARY OF PRICING ASSUMPTIONS  
as of December 31, 2005  
CONSTANT PRICES AND COSTS

Year	OIL	NATURAL GAS	NATURAL GAS LIQUIDS				EXCHANGE RATE <sup>(1)</sup> (\$US/\$Cdn)
	Edmonton Par Price 40° API (\$Cdn/Bbl)	AECO Gas Price (\$Cdn/GJ)	Edmonton Pentane (\$Cdn/Bbl)	Edmonton Propane (\$Cdn/Bbl)	Edmonton Butane (\$Cdn/Bbl)	Spec Ethane (\$Cdn/Bbl)	
Historical <sup>(2)</sup> 2005	68.27	9.71	71.67	43.69	50.52	32.92	0.8577

## Notes:

- (1) The exchange rate used to generate the benchmark reference prices in this table.
- (2) Prices as at December 31, 2005.

#### 5. Future Development Costs

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

Year	Forecast Prices and Costs		Constant Prices and Costs	
	Proved Reserves (\$000)	Proved Plus Probable Reserves (\$000)	Proved Reserves (\$000)	Proved Plus Probable Reserves (\$000)
2006	3,475	7,772	3,475	7,772
2007	352	432	345	424
2008	0	0	0	0
2009	2,547	2,552	2,400	2,405
2010	0	0	0	0
Thereafter	10	10	8	8
<b>Total Undiscounted</b>	<b>6,383</b>	<b>10,767</b>	<b>6,228</b>	<b>10,610</b>
<b>Total Discounted at 10%</b>	<b>5,447</b>	<b>9,617</b>	<b>5,335</b>	<b>9,504</b>

The Corporation has sufficient internally generated cash flow to finance the future development costs noted above.

6. The Alberta royalty tax credit ("ARTC") is included in the cumulative cash flow amounts. ARTC is based on the program announced November 1989 by the Alberta government with modifications effective January 1, 1995. The Corporation qualifies for the maximum ARTC.
7. The revenue forecasts included in the GLJ Report include the estimated costs, net of salvage value, to abandon the wells assigned reserves in the GLJ Report and to disconnect these wells from the gathering system. No costs have been included for the abandonment of surface facilities or gathering systems or for the reclamation of surface leases. **Also, no costs have been included in the GLJ Report for the abandonment of any of Rock's wells which have been assigned no reserves in the GLJ Report.**
8. Both the constant and forecast price and cost assumptions assume the continuance of current laws and regulations.
9. The extent and character of all factual data supplied to GLJ were accepted by GLJ as represented. No field inspection was conducted.

### Reconciliations of Changes in Reserves and Future Net Revenue

#### RECONCILIATION OF COMPANY NET RESERVES BY PRINCIPAL PRODUCT TYPE FORECAST PRICES AND COSTS

FACTORS	LIGHT AND MEDIUM OIL			HEAVY OIL			ASSOCIATED & NON-ASSOCIATED GAS			NATURAL GAS LIQUIDS		
	Net Proved (Mbbl)	Net Probable (Mbbl)	Net Proved Plus Probable (Mbbl)	Net Proved (Mbbl)	Net Probable (Mbbl)	Net Proved Plus Probable (Mbbl)	Net Proved (MMcf)	Net Probable (MMcf)	Net Proved Plus Probable (MMcf)	Net Proved (Mbbl)	Net Probable (Mbbl)	Net Proved Plus Probable (Mbbl)
December 31, 2004 <sup>(1)</sup>	186	23	209	151	138	289	1,427	589	2,016	40	5	46
Extensions Improved	5	1	6	769	734	1,503	0	51	51	0	0	0
Recovery Technical	16	7	22	0	0	0	51	21	72	0	0	1
Revisions Discoveries	15	13	28	40	(97)	(57)	(145)	(64)	(210)	(2)	2	0
Acquisitions	0	0	0	19	11	30	757	289	1,046	8	3	11
Dispositions	104	41	145	0	0	0	9,749	3,074	12,823	45	15	60
Economic Factors	0	0	0	0	0	0	0	0	0	0	0	0
Production	2	0	2	(1)	(1)	(1)	3	1	4	0	0	0
	(41)		(41)	(52)		(52)	(1,194)		(1,194)	(14)		(14)
December 31, 2005	286	85	371	926	786	1,712	10,648	3,960	14,608	78	25	102

Note:

(1) Figures may not add due to rounding.

#### RECONCILIATION OF CHANGES IN NET PRESENT VALUES OF FUTURE NET REVENUE DISCOUNTED AT 10% PER YEAR PROVED RESERVES CONSTANT PRICES AND COSTS

PERIOD AND FACTOR	Year Ended December 31, 2005 (M\$)
Estimated Future Net Revenue at December 31, 2004 (before Income Tax)	7,179
Sales and Transfers of Oil and Gas Produced, Net of Production Costs and Royalties	(13,118)
Net Change in Prices, Production Costs and Royalties Related to Future Production	6,542
Changes in Previously Estimated Development Costs Incurred During the Period	15,526
Changes in Estimated Future Development Costs	(15,514)
Extensions and Improved Recovery	6,329
Discoveries	4,928
Acquisitions of Reserves	53,727
Dispositions of Reserves	0
Net Change Resulting from Revisions in Quantity Estimates	865
Accretion of Discount	718
Net Change in Income Taxes	(8,527)
Net Change in Royalty Tax Credits	0
Other Changes	7,727
Estimated Future Net Revenue at December 31, 2005 (after Income Tax)	66,382

## Additional Information Relating to Reserves Data

### *Undeveloped Reserves*

Proved and probable undeveloped reserves have been estimated in accordance with procedures and standards contained in the COGE Handbook. The significant majority of the undeveloped reserves are scheduled to be developed within the next two years of the effective date.

Non-producing reserves are also forecast to be developed in 2009 at Wild River. This capital is contingent on performance and may not be necessary.

### *Significant Factors or Uncertainties*

A discussion of important economic factors and significant uncertainties that affect components of the reserves data can be found under the heading "Critical Accounting Estimates" in the Corporation's management discussion and analysis relating to the financial statements for the year ended December 31, 2005, which forms part of the Corporation's 2006 Annual Report, which discussion and analysis is incorporated herein by reference.

## Other Oil and Gas Information

### *Oil And Gas Wells*

The following table sets forth the number and status of wells in which the Corporation has a working interest as at December 31, 2005.

	Oil Wells				Natural Gas Wells			
	Producing		Non-Producing		Producing		Non-Producing	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Alberta	41	26.5	3	1.6	58	17.1	40	17.1
British Columbia	0	0.0	1	0.4	3	1.7	6	1.7
Saskatchewan	8	4.2	2	1.5	1	1.0	1	1.0
Total	49	30.7	6	3.5	62	19.8	47	19.8

### *Properties with no Attributable Reserves*

The following table sets out the Corporation's developed and undeveloped land holdings as at December 31, 2005.

	Developed Acres		Undeveloped Acres		Total Acres	
	Gross	Net	Gross	Net	Gross	Net
Alberta	69,585	26,637	58,189	24,813	127,774	51,450
British Columbia	6,777	2,725	12,457	3,972	19,234	6,698
Saskatchewan	2,826	2,016	9,020	8,113	11,846	10,128
Total	79,188	31,378	79,666	36,898	158,854	68,276

Of the Corporation's undeveloped land, rights to explore, develop and exploit 10,194 (2,565 net) acres expire by December 31, 2006. The Corporation does not have any work commitments associated with its undeveloped lands.

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

Future abandonment and reclamation costs have been estimated by management of the Corporation. Costs to abandon and reclaim approximately 119 (51.0 net) wells totalling \$2.2 million (undiscounted) and 134 (60.0 net) wells totalling \$2.5 million (undiscounted) are included in the estimate of future net revenue from total proved and total proved plus probable reserves, respectively in the GLJ Report.

An additional \$0.1 million undiscounted is the estimated cost to abandon and reclaim facilities and have not been deducted from future net revenues in the GLJ Report as the report only evaluates wells with reserves and not facilities.

The Corporation does expect to incur up to \$500,000 in abandonment or reclamation expenses in the next three fiscal years to reclaim 30 (10.3 net) abandoned wells, which are not included in the GLJ Report.

### ***Tax Horizon***

As at December 31, 2005, the Corporation has approximately \$78.0 million of tax pools, of which \$32.9 million are either non-capital losses or Canadian Exploration expense pools, therefore the Corporation does not expect to pay income taxes in 2006.

### ***Capital Expenditures***

The following tables summarize capital expenditures (net of incentives and net of certain proceeds and including capitalized general and administrative expenses) related to the Corporation's activities for the year ended December 31, 2005:

Land acquisition costs	\$3,737,172
Seismic acquisition costs	\$1,760,538
Exploration drilling and completion costs	\$2,086,717
Development drilling and completion costs	\$10,363,880
Facility and equipment costs	\$4,758,625
Acquisitions	\$60,593,475
Capitalized G&A	\$864,688
Office Equipment	\$72,310
Total	<u>\$84,237,405</u>

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

The following table sets forth the gross and net exploratory and development wells in which the Corporation participated during the year ended December 31, 2005:

	Gross	Net
Heavy Oil	14	14
Light and Medium Oil	4	1.1
Natural Gas	9	2.1
Service	0	0
Dry	6	5.2
Total:	<u>33</u>	<u>22.4</u>

A discussion of exploration and development activities is set forth under "Description of the Business and Principal Properties".

### ***Production Estimates***

The following table sets out the volume of the Corporation's production estimated for the twelve months ended December 31, 2006 which is reflected in the estimate of future net revenue disclosed in the Forecast Prices and Costs and Constant Prices and Costs tables contained under " - Disclosure of Reserves Data".

	Light and Medium Oil	Heavy Oil	Natural Gas	Natural Gas Liquids	BOE
	Gross (Bbls/d)	Gross (Bbls/d)	Gross (Mcf/d)	Gross (Bbls/d)	Gross (BOE/d)
Proved Producing	146	670	7,847	69	2,194
Proved Undeveloped	16	104	427	3	193
Total Proved	162	774	8,274	72	2,387
Total Probable	13	250	407	4	335
Total Proved Plus Probable	175	1,024	8,681	76	2,722

### Production History

The following tables summarize certain information in respect of production, product prices received and operating expenses made by the Corporation (and its subsidiaries) for the periods indicated below:

(6:1)	Quarter Ended							
	2005				2004			
	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Average Daily Production <sup>(1)</sup>								
Light & Medium Crude Oil (Bbls/d)	207	154	98	71	71	71	81	85
Heavy Crude Oil (Bbls/d)	480	107	74	82	-	-	-	-
Gas (Mcf/d)	8,147	5,985	2,879	795	665	476	433	507
NGLs (Bbls/d)	75	84	42	23	19	15	18	16
Combined (BOE/d)	2,120	1,343	693	309	201	165	171	186
Average Price Received								
Light & Medium Crude Oil (\$/Bbl)	63.63	71.13	62.30	58.89	55.90	48.29	42.26	40.59
Heavy Crude Oil (\$/Bbl)	24.81	40.60	28.18	24.91	-	-	-	-
Gas (\$/Mcf)	12.06	9.37	7.62	6.95	6.77	6.33	7.30	6.49
NGLs (\$/Bbl)	58.80	59.73	48.71	47.98	45.09	43.61	38.87	36.51
Combined (\$/BOE)	60.29	56.90	46.36	41.65	46.68	42.90	42.54	39.48
Royalties Paid								
Light & Medium Crude Oil (\$/Bbls)	2.56	24.34	11.59	8.87	9.06	8.86	8.35	7.82
Heavy Crude Oil (\$/Bbl)	5.74	7.35	3.84	4.04	-	-	-	-
Gas (\$/Mcf)	3.02	1.63	1.86	2.45	(0.21)	3.21	2.34	2.33
NGLs (\$/Bbl)	14.88	15.31	10.35	4.13	11.69	17.93	11.29	13.84
Combined (\$/BOE)	13.67	11.61	10.39	9.73	3.73	14.70	11.08	11.16
Oil Transportation Expense	0.81	0.74	0.19	0.48	0.89	-	-	-
Operating Expenses <sup>(3)</sup>								
Light & Medium Crude Oil (\$/Bbl) <sup>(3)</sup>	9.74	11.19	7.49	8.18	7.59	9.15	7.67	6.56
Heavy Crude Oil (\$/Bbl)	15.37	27.04	16.28	11.33	-	-	-	-
Gas (\$/Mcf) <sup>(3)</sup>	1.62	1.86	1.25	1.36	1.27	1.53	1.28	1.09
NGLs (\$/Bbl) <sup>(3)</sup>	9.74	11.19	7.49	8.18	7.59	9.15	7.67	6.56
Combined (\$/BOE) <sup>(3)</sup>	11.02	12.45	8.43	9.01	7.59	9.15	7.67	6.56
Netback Received <sup>(2)</sup>								
Light & Medium Crude Oil (\$/Bbl)	50.73	34.70	41.86	39.78	38.36	30.28	26.24	26.21
Heavy Crude Oil (\$/Bbl)	3.70	6.21	8.06	9.54	-	-	-	-
Gas (\$/Mcf)	7.23	5.73	4.51	3.11	5.72	1.59	3.68	3.07
NGLs (\$/Bbl)	34.17	33.23	30.87	35.68	25.81	16.53	19.91	16.11
Combined (\$/BOE)	34.79	32.10	27.35	22.43	34.27	19.05	23.79	21.76

#### Notes:

- (1) Before deduction of royalties.
- (2) Netbacks are calculated by subtracting royalties, oil transportation expense and operating expenses from revenues.
- (3) Operating expenses for light & medium crude oil, gas and NGLs have been allocated based on each product's percentage of their aggregate production.

The Corporation's crude oil production for the year ended December 31, 2005 was 12% light quality crude oil (32° API or greater), 17% heavy crude oil and 5% natural gas and liquids.

For the year ended December 31, 2005, approximately 27% of the Corporation's gross revenue was derived from crude oil production (including natural gas liquids) and 73% was derived from natural gas production.

### DIVIDEND POLICY

The Corporation has not paid any dividends to date on its common shares. The board of directors of the Corporation will determine the timing, payment and amount of dividends, if any, that may be paid by the Corporation from time to time based upon, among other things, the cash flow, results of operations and financial condition of the Corporation, the need for funds to finance ongoing operations and other business considerations as the board of directors considers relevant.

### MARKET FOR SECURITIES

The common shares of the Corporation trade on the Toronto Stock Exchange (the "TSX") under the symbol "RE". The following sets forth the price range and trading volume of the Common Shares on the TSX (as reported by the TSX) for the periods indicated.

	Price Range		Volume
	High	Low	
<b>2005</b>			
January	3.99	3.27	281,926
February	4.75	3.25	855,548
March	5.01	4.00	876,139
April	4.60	3.75	138,507
May	4.75	4.15	69,592
June	4.53	4.06	264,257
July	5.05	4.20	121,712
August	5.60	4.55	1,263,655
September	6.25	4.65	2,895,170
October	6.10	4.40	1,145,944
November	5.40	4.52	1,058,903
December	5.39	4.66	1,190,255
<b>2006</b>			
January	5.50	4.35	578,420
February	5.60	4.68	1,735,356
March (1-15)	4.75	3.90	139,113

### DIRECTORS AND OFFICERS

The names, municipalities of residence, positions with the Corporation, and principal occupation of the directors and officers of the Corporation are set out below and in the case of directors, the period each has served as a director of the Corporation.

Name and Municipality of Residence	Office Held	Principal Occupation	Director Since
Allen J. Bey <sup>(4)</sup> Calgary, Alberta	President, Chief Executive Officer and Director	President and CEO of Rock since January 2004. From January 2003 to January 2004 President and CEO of Rock Energy. From January 1996 until it was sold in July 2001 President and CEO of Avid Oil and Gas Ltd (a public oil and gas company).	October 3, 2003

Name and Municipality of Residence	Office Held	Principal Occupation	Director Since
Peter D. Scott Calgary, Alberta	Vice, President Finance and Chief Financial Officer	Vice President, Finance and CFO of Rock since January 2004. From March 2003 to January 2004 Vice President, Finance and CFO of Rock Energy. From March 2000 to March 2003 Executive Vice President and CFO of Absolute Software Corporation (a public software development company). From March 1997 to March 2000 Vice President Finance and CFO of Beau Canada Exploration Ltd. (a public oil and gas company).	N/A
Alexander C. Brown Calgary, Alberta	Vice President, Exploration	Vice President, Exploration of Rock since January 2004. From January 2003 to January 2004 Vice President, Exploration of Rock Energy. From July 2001 to December 2003 Senior Geologist for Northrock Resources Ltd. (a public oil and gas company). From July 1994 to March 2001 Mr. Brown was employed in various positions of increasing responsibility at Fletcher Challenge Energy Canada (the Canadian subsidiary of a public oil and gas company) the last being Exploration & Development Asset Manager: Provost District.	N/A
Sean E. Moore Calgary, Alberta	Vice President, Production	Vice President, Production of Rock since January 2004. From January 2003 to January 2004 Vice President, Production of Rock Energy. From October 2001 to January 2003 Deep Plains Business Unit Manager for Vintage Petroleum Canada Inc. (the Canadian subsidiary of a public oil and gas company). From 1992 to March 2001 Mr. Moore was employed in various positions of increasing responsibility at Fletcher Challenge Energy Canada the last being Vice President Exploration and Development until it was purchased by Apache Canada Ltd. (the Canadian subsidiary of a public oil and gas company). Mr. Moore continued on for transitional purposes with Apache Canada Ltd. until June 2001 as a consulting engineer.	N/A
Grant A. Zawalsky Calgary, Alberta	Corporate Secretary	Partner of Burnet, Duckworth & Palmer LLP (lawyers)	N/A
Stuart G. Clark <sup>(1)(2)(3)</sup> Calgary, Alberta	Director	Independent businessman. From August 2002 to July 2004 Executive Director of Storm Energy Ltd. (a public oil and gas company). From November 1998 to November 2001 Vice President Finance and CFO of Storm Energy Inc. (a public oil and gas company), then from November 2001 to August 2002 Executive Director of Storm Energy Inc. From January 1986 to July 1998 Mr. Clark was employed in various positions of increasing responsibility the last being Executive Vice President and CFO of Pinnacle Resources Ltd. (a public oil and gas company).	January 8, 2004
Peter Malowany <sup>(1)(4)</sup> Calgary, Alberta	Director	Since March 2005 President and from April 2001 to March 2005 partner and Vice President of Morgas Ltd. (a private oil and gas company). From April 1996 to April 2001 partner and Vice President of Newhouse Resource Management Ltd. (a private oil and gas company).	January 8, 2004

Name and Municipality of Residence	Office Held	Principal Occupation	Director Since
Matthew J. Brister <sup>(3)(4)</sup> Calgary, Alberta	Director	Since August 2003 President of Storm Ventures International Inc. (a private oil and gas company). From August 2002 to July 2004 President and CEO of Storm Energy Ltd. (a public oil and gas company). From November 1998 to August 2002 President and CEO of Storm Energy Inc. (a public oil and gas company). From January 1987 to July 1998 Mr. Brister was employed in various positions of increasing responsibility the last being President and CEO of Pinnacle Resources Ltd. (a public oil and gas company).	October 28, 2004
James K. Wilson <sup>(1)(3)</sup> Calgary, Alberta	Director	Since September 2004 Vice President, Finance and CFO of Grizzly Resources Ltd. (a private oil and gas company). From January 2002 to September 2004 Vice President, Finance and CFO of Archean Energy Ltd. (a private oil and gas company). From March 2000 to October 2001 Senior Vice President, Finance & CFO and Corporate Secretary of Grey Wolf Exploration Inc. (a public oil and gas company). From March 1999 to March 2000 was Vice President, Finance and CFO of Maxx Petroleum Ltd. (a public oil and gas company). From January 1998 to September 1998 was Executive Vice President, Finance and CFO of Chauvco Resources International Ltd. (a public oil and gas company). From August 1990 to December 1997 was Senior Vice President, Finance and Administration & CFO of Chauvco Resources Ltd. (a public oil and gas company).	October 28, 2004

## Notes:

- (1) Member of the Audit Committee of the Corporation.
- (2) Chairman of the Board.
- (3) Member of the Compensation, Nomination and Governance Committee of the Corporation.
- (4) Member of the Reserves Committee of the Corporation.
- (5) The Corporation does not have an Executive Committee of its Board of Directors.

All of the directors and officers of Rock have been engaged for more than five years in their present principal occupations or executive positions with the same companies except as described above.

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

As at March 16, 2006, the directors and officers of the Corporation, as a group, beneficially owned, directly or indirectly, 2,865,077 common shares or approximately 14.6% of the issued and outstanding common shares of the Corporation .

### Corporate Cease Trade Orders or Bankruptcies

No director, officer or promoter of the Corporation has, within the last 10 years, been a director, officer or promoter of any reporting issuer that, while such person was acting in that capacity, was the subject of a cease trade or similar order or an order that denied the company access to any statutory exemption for a period of more than 30 consecutive days or was declared a bankrupt or made a voluntary assignment in bankruptcy, made a proposal under any legislation relating to bankruptcy or been 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 that person other than James K. Wilson as Executive Vice President and CFO of Chauvco Resources International Ltd. from January 1998 to September 1998 when the trading of shares of Chauvco Resources International Ltd. were suspended by the Toronto and Montreal exchanges in July 1998 and were subsequently delisted.

### **Penalties or Sanctions**

No director, officer or promoter of the Corporation, within the last 10 years, has been subject to any penalties or sanctions imposed by a court or securities regulatory authority relating to trading in securities, promotion or management of a publicly traded issuer or theft or fraud.

### **Personal Bankruptcies**

No director, officer or promoter of the Corporation, or a shareholder holding sufficient securities of the Corporation to affect materially the control of the Corporation, or a personal holding company of any such persons, has, within the last 10 years, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or being 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 individual.

### **Conflicts of Interest**

Directors and officers of the Corporation may, from to time, be involved with the business and operations of other oil and gas issuers, in which case a conflict may arise. See "Risk Factors".

## **ESCROWED SECURITIES**

To the knowledge of the Corporation, no securities of the Corporation are held in escrow.

## **AUDIT COMMITTEE INFORMATION**

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

The Mandate and Terms of Reference of the Audit Committee of the board of director's is attached hereto as Schedule "C". The members of the Audit Committee are Stuart G. Clark, Peter Malowany and James K. Wilson.

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

The members of the Audit Committee are independent (in accordance with National Instrument 52-110) and are financially literate.

### **Relevant Education and Experience**

Mr. James K. Wilson is the Chairman of the Audit Committee and holds a Bachelor of Commerce degree and a Chartered Accountant designation. Mr. Wilson is currently the Chief Financial Officer of an oil and gas company and has held that position at several predecessor companies. Mr. Wilson has over 22 years of financial experience in the oil and gas industry. Mr. Stuart G. Clark currently serves on several Audit Committees and has previously been the Chief Financial Officer of several public oil and gas companies. Mr. Clark has over 18 years of financial experience in the oil and gas industry and holds a Bachelor of Commerce degree. Mr. Peter Malowany is a professional engineer and has over 30 years experience in the oil and gas industry, many of them at the executive and board level. Mr. Malowany's experience has afforded him the opportunity to become knowledgeable with respect to financial and accounting matters in the oil and gas industry.

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

The Audit Committee, typically on an annual basis, approves a budget for audit and non-audit services to be performed at the Corporation. The budget is set after consultation with management of the Corporation and the Corporation's auditors. The non audit services budget is usually set at the same amount as for audit services. From time to time management of the Corporation may request approval by the committee of additional funding for special projects such as acquisition related advice.

Any changes in accounting policies are discussed in advance of their implementation with either the Chairman of the Audit Committee or the Audit Committee.

**External Auditor Service Fees**

The aggregate fees billed by the Corporation's external auditor in the last fiscal year for audit services were \$48,752 in 2005.

***Audit and Related Fees***

The aggregate fees billed in the last fiscal year for assurance audit related services by the Corporation's external auditor were \$92,456 in 2005. The services provided consisted of review of quarterly statements and disclosure and advice on accounting matters related to the business acquisition.

***Tax Fees***

The aggregate fees billed in the last fiscal year for professional services rendered by the Corporation's external auditor for tax compliance, tax advice and tax planning were \$58,750 in 2005.

**LEGAL PROCEEDINGS**

There are no legal proceedings which the Corporation or any subsidiary of the Corporation is a party or of which any of their property is subject which are material to the Corporation and the Corporation is not aware of any such proceedings that are contemplated or pending.

**INTERESTS OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS**

There were no material interests, direct or indirect, of directors and senior officers of the Corporation, any shareholder who beneficially owns more than 10% of the outstanding Common Shares, or any known associate or affiliate of such persons, in any transaction within the last fiscal year and in any proposed transaction which has materially affected or would materially affect the Corporation.

**MATERIAL CONTRACTS**

Except for contracts entered into in the ordinary course of business, there are no material contracts entered into by the Corporation within the most recently completed financial year, or before the most recently completed financial year but still in effect.

**INTERESTS OF EXPERTS**

There is no person or company whose profession or business gives authority to a statement made by such person or company and who is named as having prepared or certified a statement, report or valuation described or included in a filing, or referred to in a filing, made under National Instrument 51-102 by the Corporation during, or related to, the Corporation's most recently completed financial year other than GLJ, the Corporation's independent engineering evaluator and KPMG LLP, the Corporation's auditors.

None of the principals of GLJ had any registered or beneficial interests, direct or indirect, in any securities or other property of the Corporation or of the Corporation's associates or affiliates either at the time they prepared the statement, report or valuation prepared by it, at any time thereafter or to be received by them.

KPMG LLP and its partners did not hold any registered or beneficial interests, directly or indirect, in the securities of the Corporation or its associates or affiliates.

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 the Corporation or of any associate or affiliate of the Corporation.

## **HUMAN RESOURCES**

The Corporation currently employs 15 full-time employees and utilizes the services of professionals, as required from time to time on a contract or consulting basis. The Corporation intends to add additional professional and administrative staff as the needs arise.

## **AUDITORS, TRANSFER AGENT AND REGISTRAR**

The auditors of the Corporation are KPMG LLP, Chartered Accountants, Suite 1200, 205 – 5th Avenue SW, Calgary, Alberta T2P 4B9.

Computershare Trust Company of Canada, at its principal offices in Calgary, Alberta and Toronto, Ontario is the transfer agent and registrar of the common shares of the Corporation.

## **RISK FACTORS**

An investment in the common shares of the Corporation should be considered speculative due to the nature of the Corporation's businesses and operations, including in particular their involvement in the, acquisition, exploitation, development, production and marketing of crude oil and natural gas and their present stages of development. In addition to the other information in this Annual Information Form, shareholders should carefully consider each, and the cumulative effect of all, of the following factors.

The reserve and recovery information contained in the GLJ Report are only estimates and the actual production and ultimate reserves from the Corporation's properties may be greater or less than the estimates prepared in such report. The GLJ Report has been prepared using certain commodity price assumptions which are described in the notes to the reserve tables. If lower prices for crude oil, natural gas liquids and natural gas are realized by the Corporation and substituted for the price assumptions utilized in the GLJ Report, the present value of estimated future net cash flows for the Corporation's reserves would be reduced and the reduction could be significant, particularly based on the constant price case assumptions. Exploration for oil and natural gas involves many risks, which even a combination of experience and careful evaluation may not be able to overcome. There is no assurance that further commercial quantities of oil and natural gas will be discovered by the Corporation.

The future development of the Corporation's oil and natural gas properties may require additional financing and there are no assurances that such financing will be available or, if available, will be available upon acceptable terms.

The Corporation's operations are subject to the risks normally incidental to the operation and development of oil and natural gas properties and the drilling of oil and natural gas wells, including encountering unexpected formations or pressures, blow-outs and fires, all of which could result in personal injuries, loss of life and damage to property of the Corporation and others. In accordance with customary industry practice, the Corporation is not fully insured against all of these risks, nor are all such risks insurable. Although the Corporation maintains liability insurance in an amount which it considers adequate and consistent with industry practice, the nature of these risks is such that liabilities could exceed policy limits, in which event it could incur significant costs that could have a material adverse affect upon its financial condition. Oil and natural gas production operations are also subject to all the risks typically associated with such operations, including premature decline of reservoirs and the invasion of water into producing formations.

Environmental regulation is becoming increasingly stringent and costs and expenses of regulatory compliance are increasing. Although the Corporation believes that it is in material compliance with currently applicable environmental regulation, changes to such regulations may have a material adverse affect on the Corporation. Additionally, the potential impact on the Corporation's operations and business of the Kyoto Protocol which has now been ratified by Canada, with respect to instituting reductions of greenhouse gases is difficult to quantify at this time as specific measures for meeting Canada's commitments have not been developed.

Continuing production from a property, and to some extent the marketing of production therefrom, are largely dependent upon the ability of the operator of the property. Operating costs on most properties have increased steadily over recent years. To the extent the operator fails to perform these functions properly, revenue may be reduced. Payments from production generally flow through the operator and there is a risk of delay and additional expense in receiving such

revenues if the operator becomes insolvent. Both oil and natural gas prices are unstable and are subject to fluctuation. Any material decline in prices could result in a reduction of the Corporation's net production revenue. The economics of producing from some wells may change as a result of lower prices, which could result in a reduction in the volumes of the Corporation's reserves. The Corporation might also elect not to produce from certain wells at lower prices. All of these factors could result in a material decrease in the Corporation's net production revenue causing a reduction in its oil and gas acquisition and development activities. In addition, bank borrowings that may be available to the Corporation may be in part determined by the company's borrowing base. A sustained material decline in prices from historical average prices could further reduce such borrowing base, therefore reducing the bank credit available and could require that a portion of its bank debt be repaid.

The Corporation uses the full cost method of accounting for oil and natural gas properties. Under this accounting method, capitalized costs are reviewed for impairment to ensure that the carrying amount of these costs is recoverable based on expected future cash flows. To the extent that such capitalized costs (net of accumulated depreciation and depletion) less future taxes exceed the present value of estimated future net cash flows from its proved oil and natural gas reserves, those excess costs would be required to be charged to operations. Canadian Generally Accepted Accounting Principles ("GAAP") require that management apply certain accounting policies and make certain estimates and assumptions which affect reported amounts in the consolidated financial statements of the Corporation. 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 result in an inability to borrow funds and/or may result in a decline in the trading prices of the common shares of the Corporation. 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, the Corporation 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. 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 trading price of the common shares of the Corporation may indicate a goodwill impairment. 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. Emerging GAAP surrounding hedge accounting may result in non-cash charges against net income as a result of changes in the fair market value of hedging instruments. A decrease in the fair market value of the hedging 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.

The Corporation (including Medbroadcast as well as Rock Energy) is or has been engaged in one or more of the technology, mining or oil and natural gas business and its operations are subject to certain unique provisions of the *Income Tax Act* (Canada) and applicable provincial income tax legislation relating to characterization of costs incurred in its business which effects whether such costs are deductible and, if deductible, the rate at which they may be deducted for the purposes of calculating taxable income. The Corporation has reviewed the income tax returns of Medbroadcast with respect to the characterization of the costs incurred in either the technology or the resource property business, as applicable, as well as other matters generally applicable to all corporations including the ability to offset future income against prior year losses. The Corporation (including Medbroadcast as well as Rock Energy) has filed or will file all required income tax returns and believe that it is in full compliance with the provisions of the *Income Tax Act* (Canada) and applicable provincial income tax legislation, but such returns are subject to reassessment. In the event of a successful reassessment of the Corporation (including Medbroadcast as well as Rock Energy) it may be subject to a higher than expected past or future income tax liability as well as potentially interest and penalties and such amount could be material.

From time to time the Corporation may enter into agreements to receive fixed prices on its oil and natural gas production to offset the risk of revenue losses if commodity prices decline; however, if commodity prices increase beyond the levels set in such agreements, the Corporation will not benefit from such increases and the Corporation may nevertheless be obligated to pay royalties on such higher prices, even though not received by it, after giving effect to such agreements.

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 the Corporation's 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 the receipt by the Corporation of fewer Canadian dollars for its production. From time to time the Corporation may enter into agreements to fix the exchange rate of Canadian to United States dollars in order to offset the risk of revenue losses if the Canadian dollar increases in value compared to the United States dollar; however, if the Canadian dollar declines in value compared to the United States dollar, it will not benefit from the fluctuating exchange rate.

There are numerous uncertainties inherent in estimating quantities of reserves and cash flows to be derived therefrom, including many factors that are beyond the control of the Corporation. These evaluations include a number of assumptions relating to factors such as initial production rates, production decline rates, ultimate recovery of reserves, timing and amount of capital expenditures, marketability of production, future prices of oil and natural gas, operating costs and royalties and other government levies that may be imposed over the producing life of the reserves. These assumptions were based on price forecasts in use at the date the relevant evaluations were prepared and many of these assumptions are subject to change and are beyond the control of the Corporation. Actual production and cash flows derived therefrom will vary from these evaluations, and such variations could be material. The foregoing evaluations are based in part on the assumed success of exploitation activities intended to be undertaken in future years. The reserves and estimated cash flows to be derived therefrom contained in such evaluations will be reduced to the extent that such exploitation activities do not achieve the level of success assumed in the evaluations.

The marketability and price of oil and natural gas which may be acquired or discovered by the Corporation will be affected by numerous factors beyond its control. The Corporation will be affected by the differential between the price paid by refiners for grades of oil produced by the Corporation. The ability of the Corporation to market its natural gas may depend upon its ability to acquire space on pipelines which deliver natural gas to commercial markets. The Corporation is also subject to market fluctuations in the prices of oil and natural gas, deliverability uncertainties related to the proximity of its reserves to pipelines and processing facilities and related to operational problems with such pipelines and facilities and extensive government regulation relating to price, taxes, royalties, land tenure, allowable production, the export of oil and natural gas and many other aspects of the oil and natural gas business. The Corporation is also subject to a variety of waste disposal, pollution control and similar environmental laws. The oil and natural gas industry is intensely competitive and the Corporation must compete in all aspects of its operations with a substantial number of other corporations which have greater technical or financial resources.

Title to oil and natural gas interests is often not capable of conclusive determination without incurring substantial expense. In accordance with industry practice, the Corporation conducts such title reviews in connection with its principal properties as it believes are appropriate having regard to the value of such properties. To the extent title defects do exist, it is possible that the Corporation may lose a portion of its right, title, estate and interest in and to the properties to which the title relates.

The Corporation does not anticipate paying any dividends on its outstanding shares in the foreseeable future.

The directors of the Corporation may be engaged and may continue to be engaged in the search for oil and gas interests on their own behalf and on behalf of other companies, and situations may arise where the directors may be in direct competition with the Corporation. Conflicts of interest, if any, which arise will be subject to and governed by procedures prescribed by the corporation's governing corporate law statute which require a director of a corporation who is a party to, or is a director or an officer of, or has some material interest in any person who is a party to, a material contract or proposed material contract with the Corporation, disclose his or her interest and, in the case of directors, to refrain from voting on any matter in respect of such contract unless otherwise permitted under such legislation.

Holders of common shares of the Corporation must rely upon the experience and expertise of the management of the Corporation. The continued success of the Corporation is largely dependant on the performance of its key employees. Failure to retain or to attract and retain additional key employees with necessary skills could have a materially adverse impact upon the company's growth and profitability.

## **INDUSTRY CONDITIONS**

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 the operations of Rock 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 Rock is unable to predict what additional legislation or amendments may be enacted. Outlined below are some of the principal aspects of legislation, regulations and agreements governing the oil and gas industry.

### **Pricing and Marketing – Oil, Natural Gas and Associated Products**

In the provinces of Alberta, British Columbia and Saskatchewan oil, natural gas and associated products are generally sold at market index based prices. These indices are generated at various sales points depending on the commodity and are reflective of the current value of the commodity adjusted for quality and locational differentials. While these indices tend to track industry reference prices (ie. price of West Texas Intermediate crude oil at Cushing, Oklahoma or price of natural gas at Henry Hub, Louisiana), some variances can occur due to specific supply-demand imbalances. These differentials can change on a monthly or daily basis depending on the supply-demand fundamental at each location as well as other non-related changes such as the value of the Canadian dollar and the cost of transporting the commodity to the pricing point of the particular index.

The producers of oil are entitled to negotiate sales contracts directly with oil purchasers, with the result that the market determines the price of oil. Oil prices are primarily based on worldwide supply and demand. The specific price depends in part on oil quality, prices of competing fuels, distance to market, the value of refined products, the supply/demand balance and 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 (the "NEB"). Any oil export to be made pursuant to a contract of longer duration (to a maximum of 25 years) requires an exporter to obtain an export license from the NEB and the issuance of such license 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 exports for a term of less than 2 years or for a term of 2 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 license from the NEB and the issuance of such license 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 continues to affect the oil and natural gas industry and limits 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 or in such other representative period as the parties may agree); (ii) impose an export price higher than the domestic price subject to an exception with respect to certain measures which only restrict the volume of exports; and (iii) disrupt normal channels of supply. All three 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 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.

From time to time 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 allow such incentive programs to expire without renewal, and consequently few such incentive programs are currently operative.

On March 3, 2003 the Department of Finance (Canada) released a technical paper entitled "Improving the Income Taxation of the Resource Sector in Canada" (the "Technical Paper"). In November, 2003 the Tax Act was amended to provide the following initiatives applicable to the oil and gas industry (to a maximum of \$2,000,000) to be phased in over a five year period: (i) a reduction of the federal statutory corporate income tax rate on income earned from resource activities from 28% to 21%, beginning with a one percentage point reduction effective January 1, 2003, and (ii) a deduction for federal income tax purposes of actual provincial and other Crown royalties and mining taxes paid and the elimination of the 25% resource allowance. In addition, the percentage of Alberta royalty tax credit that Rock will be required to include in federal taxable income will be 12.5% in 2004; 17.5% in 2005; 32.5% in 2006; 50% in 2007; 60% in 2008; 70% in 2009; 80% in 2010; 90% in 2011, and 100% in 2012 and beyond.

### ***Alberta***

Regulations made pursuant to the *Mines and Minerals Act* (Alberta) provide various incentives for exploring and developing oil reserves in Alberta. Oil produced from horizontal extensions commenced at least 5 years after the well was originally spudded may also qualify for a royalty reduction. A 24-month, 8,000 m<sup>3</sup> exemption is available to production from a reactivated well that has not produced for: (i) a 12-month period, if resuming production in October, November or December of 1992 or January, 1993; or (ii) a 24 month period, if resuming production in February 1993 or later. As well, oil production from eligible new field and new pool wildcat wells and deeper pool test wells spudded or deepened after September 30, 1992 is entitled to a 12-month royalty exemption (to a maximum of \$1 million). Oil produced from low productivity wells, enhanced recovery schemes (such as injection wells) and experimental projects is also subject to royalty reductions.

Oil royalty rates vary from province to province. In Alberta, oil royalty rates vary between 10% and 35% for oil and 10% and 30% for new oil. New oil is applicable to oil pools discovered after March 31, 1974 and prior to October 1, 1992. The

Alberta government introduced the Third Tier Royalty with a base rate of 10% and a rate cap of 25% for oil pools discovered after September 30, 1992.

Effective January 1, 1994, the calculation and payment of natural gas royalties became subject to a simplified process. 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 exploratory natural gas wells spudded or deepened after July 31, 1985 and before June 1, 1988 continues to be eligible for a royalty exemption for a period of 12 months, or such later time that the value of the exempted royalty quantity equals a prescribed maximum amount. Natural gas produced from qualifying intervals in eligible natural gas wells spudded or deepened to a depth below 2,500 meters 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, 2007, which, among other things, determines the Crown's share of crude and processed oil sands products.

In Alberta, a producer of oil or natural gas is entitled to a credit on qualified oil and natural gas production against the royalties payable to the Crown by virtue of the Alberta royalty tax credit ("ARTC") program. The ARTC rate is based on a price sensitive formula and the ARTC rate varies between 75% at prices at and below \$100 per m<sup>3</sup> and 25% at prices at and above \$210 per m<sup>3</sup>. Crude oil and natural gas royalty programs for specific wells and royalty reductions reduce the amount of Crown royalties paid by Rock to the provincial governments. In general, the ARTC program provides a rebate on Alberta Crown royalties paid in respect of eligible producing properties. The ARTC rate is applied to a maximum of \$2,000,000 of Alberta Crown royalties payable for each producer or associated group of producers. Crown royalties on production from producing properties acquired from a corporation claiming maximum entitlement to ARTC will generally not be eligible for ARTC. The rate will be established quarterly based on the average "par price", as determined by the Alberta Department of Energy for the previous quarterly period.

On December 22, 1997, the Alberta government announced that it was conducting a review of the ARTC program with the objective of setting out better targeted objectives for a smaller program and to deal with administrative difficulties. On August 30, 1999, the Alberta government announced that it would not be reducing the size of the program but that it would introduce new rules to reduce the number of persons who qualify for the program. The new rules will preclude companies that pay less than \$10,000 in royalties per year and non-corporate entities from qualifying for the program. Such rules will not presently preclude Rock from being eligible for the ARTC program.

### ***British Columbia***

Producers of oil and natural gas in the Province of British Columbia are also required to pay annual rental payments in respect of the Crown leases and royalties and freehold production taxes in respect of oil and gas produced from Crown and freehold lands, respectively. 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). Oil produced from newly discovered pools may be exempt from the payment of a royalty for the first 36 months of production. The royalty payable on 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. 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 meters 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 per cent.
- 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.

### **Land Tenure**

Crude oil and natural gas located in Western Canada 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 on freehold lands are granted by lease on such terms and conditions as may be negotiated.

### **Environmental Regulation**

The oil and natural gas industry is subject to environmental regulation pursuant to a variety of international conventions and Canadian federal, provincial and municipal laws, regulations, and guidelines. Such regulation 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 regulation requires that well and facility sites be abandoned and reclaimed to the satisfaction of provincial authorities. Compliance with such regulation 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 "AEPEA"), which came into force on September 1, 1993 and the *Oil and Gas Conservation Act* (Alberta) (the "OGCA"). The AEPEA and OGCA impose stricter environmental standards, requires more stringent compliance, reporting and monitoring obligations and significantly increase penalties. Rock is committed to meeting its responsibilities to protect the environment wherever it operates and anticipates 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 AEPEA and similar legislation in other jurisdictions in which it operates. Rock believes that it is in material compliance with applicable environmental laws and regulations and also believes that it is reasonably likely that the trend towards stricter standards in environmental legislation and regulation will continue.

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.

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. In April 2005, Environment Canada released "Project Green", a working paper giving early indications of how implementation was to be achieved. Large Final Emitters ("LFEs"), being 700 of Canada's largest emitters, will receive a specific reduction target of 45 mt, and will have the opportunity to purchase domestic offset and technology credits. The exact mechanism for operating in the domestic credit market has yet to be revealed, and the prospect of non-LFE enterprise participating in that market to any great extent is uncertain. Various incentive funds have also been established to provide seed funding for the purchase of experimental technologies, encourage investment in alternative energy sources, and acquire credits from the domestic and international markets for re-sale to Canadian enterprise.

Environment Canada, in August 2005, released consultation papers for the management of a system of greenhouse gas offsets in the form of tradable and bankable credits. The credits are created by enterprise, individuals, or municipal government through the implementation of projects registered with the to-be-created offset authority. Standards for quantifying greenhouse gas reductions were also proposed in the consultation paper.

#### **ADDITIONAL INFORMATION**

Additional information, including directors' and officers' remuneration and indebtedness, principal holders of the Corporation's securities, options to purchase securities and interests of insiders in material transactions, if applicable, is contained in the Corporation's Information Circular - Proxy Statement dated March 16, 2006, which relates to the Annual General Meeting of Shareholders to be held on May 11, 2006. Additional financial information is contained in the consolidated financial statements of the Corporation for the year ended December 31, 2005 and the Management's Discussion and Analysis contained in the Corporation's 2004 Annual Report for December 31, 2005.

The Corporation will provide to any person or corporation, upon request to the Corporation:

- (a) when the securities of the Corporation are in the course of a distribution pursuant to a preliminary short form prospectus or a short form prospectus:
  - (i) one copy of the Corporation's annual information form, together with one copy of any document, or the pertinent pages of any document, incorporated therein by reference;
  - (ii) one copy of the comparative financial statements of Rock for its most recently completed financial year in respect of which such financial statements have been issued, together with the report of the auditor thereon, and one copy of any interim financial statements of the Corporation subsequent to the financial statements for Rock's most recent financial year;
  - (iii) one copy of the management information circular of the Corporation in respect of its most recent annual meeting of shareholders that involved the election of directors or one copy of any annual filing prepared in lieu of that circular, as appropriate, and

- (iv) one copy of any other document that is incorporated by reference into the preliminary short form prospectus or the short form prospectus and are not required to be provided under (i) to (iii) above; or
- (b) at any other time, a copy of the documents referred to in clauses (a)(i), (ii) or (iii) above, provided the Corporation may require a payment of a reasonable charge if the request is made by a person or Corporation who is not a security holder of the Corporation.

Additional copies of this Annual Information Form and the materials listed in the preceding paragraph are available on the foregoing basis and upon request by contacting the Corporation at its offices at 1800, 700 – 9th Avenue S.W., Calgary, Alberta T2P 3V4, or by phone at (403) 218-4380, fax at (403) 234-0598 or email at [info@rockenergy.ca](mailto:info@rockenergy.ca).

**SCHEDULE "A"**

**REPORT ON RESERVES DATA  
BY  
INDEPENDENT QUALIFIED RESERVES  
EVALUATOR OR AUDITOR**

To the board of directors of Rock Energy Inc. (the "Company"):

1. We have prepared an evaluation of the Company's reserves data as at December 31, 2005. The reserves data consist of the following:
  - (a)
    - (i) proved and proved plus probable oil and gas reserves estimated as at December 31, 2005 using forecast prices and costs; and
    - (ii) the related estimated future net revenue; and
  - (b)
    - (i) proved oil and gas reserves estimated as at December 31, 2005 using constant prices and costs; and
    - (ii) the related estimated future net revenue.
2. The reserves data are the responsibility of the Company's management. Our responsibility is to express an opinion on the reserves data based on our evaluation.
3. 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).
4. 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.
5. The following table sets forth the estimated future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated by us for the year ended December 31, 2004, and identifies the respective portions thereof that we have audited, evaluated and reviewed and reported on to the Company's board of directors:

Independent Qualified Reserves Evaluator or Auditor	Description and Preparation Date of Evaluation Report	Location of Reserves (County or Foreign Geographic Area)	Net Present Value of Future Net Revenue (before income taxes, 10% discount rate)			
			Audited	Evaluated	Reviewed	Total
GLJ Petroleum Consultants Ltd.	March 16, 2005	Canada	\$nil	\$87,315,000	\$nil	\$87,315,000

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

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

Executed as to our report referred to above:

GLJ Petroleum Consultants Ltd.  
Calgary, Alberta, Canada  
March 16, 2006

ORIGINALLY SIGNED BY  
Dana B. Laustsen, P.Eng.

## **SCHEDULE "B"**

### **REPORT OF MANAGEMENT AND DIRECTORS ON RESERVES DATA AND OTHER INFORMATION**

Management of Rock Energy Inc. (the "Company") are responsible for the preparation and disclosure of information with respect to the Company's oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data, which consist of the following:

- (a) (i) proved and proved plus probable oil and gas reserves estimated as at December 31, 2005 using forecast prices and costs; and
- (ii) the related estimated future net revenue; and
- (b) (i) proved oil and gas reserves estimated as at December 31, 2005 using constant prices and costs; and
- (ii) the related estimated future net revenue.

An independent qualified reserves evaluator has evaluated the Company's reserves data. The report of the independent qualified reserves evaluator is presented on Schedule "A" of this Annual Information Form.

The Reserves Committee of the board of directors of the Company has:

- (c) reviewed the Company's procedures for providing information to the independent qualified reserves evaluator;
- (d) 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
- (e) reviewed the reserves data with management and the independent qualified reserves evaluator.

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

- (f) the content and filing with securities regulatory authorities of the reserves data and other oil and gas information;
- (g) the filing of the report of the independent qualified reserves evaluator on the reserves data; and
- (h) 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.

(signed) "Allen J. Bey"  
Allen J. Bey  
President and Chief Executive Officer

(signed) "Sean E. Moore"  
Sean E. Moore  
Vice President, Production

(signed) "Peter Malowany"  
Peter Malowany  
Director and Chairman of the Reserves Committee

(signed) "Matthew J. Brister"  
Matthew J. Brister  
Director and Member of the Reserves Committee

March 16, 2005

**SCHEDULE "C"**  
**ROCK ENERGY INC.**  
**AUDIT COMMITTEE**

**MANDATE**

**Role and Objective**

The Audit Committee (the "Committee") is a committee of the board of directors (the "Board") of Rock Energy Inc. ("Rock" or the "Corporation") to which the Board has delegated its responsibility for the oversight of the nature and scope of the annual audit, the oversight of management's reporting on internal accounting standards and practices, the review of financial information, accounting systems and procedures, financial reporting and financial statements and has charged the Committee with the responsibility of recommending, for approval of the Board, the audited financial statements, interim financial statements and other mandatory disclosure releases containing financial information.

The primary objectives of the Committee are as follows:

- a. To assist directors in meeting their responsibilities (especially for accountability) in respect of the preparation and disclosure of the financial statements of Rock and related matters;
- b. To provide better communication between directors and external auditors;
- c. To enhance the external auditor's independence;
- d. To increase the credibility and objectivity of financial reports; and
- e. 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**

- a. The Committee will be comprised of at least three (3) directors of Rock or such greater number as the Board may determine from time to time and all members of the Committee shall be "independent" (as such term is used in Multilateral Instrument 52-110 — Audit Committees ("MI 52-110") unless the Board determines that the exemption contained in MI 52-110 is available and determines to rely thereon.
- b. The Board of Directors may from time to time designate one of the members of the Committee to be the Chair of the Committee.
- c. All of the members of the Committee must be "financially literate" (as defined in MI 52-110) unless the Board determines that an exemption under MI 52-110 from such requirement in respect of any particular member is available and determines to rely thereon in accordance with the provisions of MI 52-110.

**Mandate and Responsibilities of Committee**

It is the responsibility of the Committee to:

- a. Oversee the work of the external auditors, including the resolution of any disagreements between management and the external auditors regarding financial reporting.
- b. Satisfy itself on behalf of the Board that Rock's internal control systems are satisfactory for the purposes of:
  - identifying, monitoring and mitigating business risks; and

- ensuring compliance with legal, ethical and regulatory requirements.
- c. Review the annual and interim financial statements of Rock and related management's discussion and analysis ("MD&A") prior to their submission to the Board for approval. The process should include but not be limited to:
- reviewing changes in accounting principles and policies, or in their application, which may have a material impact on the current or future years' financial statements;
  - reviewing significant accruals, reserves or other estimates such as the ceiling test calculation;
  - reviewing accounting treatment of unusual or non-recurring transactions;
  - ascertaining compliance with covenants under loan agreements;
  - reviewing disclosure requirements for commitments and contingencies;
  - reviewing adjustments raised by the external auditors, whether or not included in the financial statements;
  - reviewing unresolved differences between management and the external auditors; and
  - obtain explanations of significant variances with comparative reporting periods.
- d. Review the financial statements, prospectuses, MD&A, annual information forms ("AIF") and all public disclosure containing audited or unaudited financial information (including, without limitation, annual and interim press releases and any other press releases disclosing earnings or financial results) before release and prior to Board approval. The Committee must be satisfied that adequate procedures are in place for the review of Rock's disclosure of all other financial information and will periodically access the accuracy of those procedures.
- e. With respect to the appointment of external auditors by the Board:
- recommend to the Board the external auditors to be nominated;
  - recommend to the Board the terms of engagement of the external auditor, including the compensation of the auditors and a confirmation that the external auditors will report directly to the Committee;
  - on an annual basis, review and discuss with the external auditors all significant relationships such auditors have with the Corporation to determine the auditors' independence;
  - when there is to be a change in auditors, review the issues related to the change and the information to be included in the required notice to securities regulators of such change; and
  - review and pre-approve any non-audit services to be provided to Rock or its subsidiaries by the external auditors and consider the impact on the independence of such auditors. The Committee may delegate to one or more independent members the authority to pre-approve non-audit services, provided that the member(s) report to the Committee at the next scheduled meeting such pre-approval and the member(s) comply with such other procedures as may be established by the Committee from time to time.
- f. Review with external auditors (and internal auditor if one is appointed by Rock) their assessment of the internal controls of Rock, their written reports containing recommendations for improvement, and management's response and follow-up to any identified weaknesses. The Committee will also review

annually with the external auditors their plan for their audit and, upon completion of the audit, their reports upon the financial statements of Rock and its subsidiaries.

- g. Review risk management policies and procedures of Rock (i.e. hedging, litigation and insurance).
- h. Establish a procedure for:
  - the receipt, retention and treatment of complaints received by Rock regarding accounting, internal accounting controls or auditing matters; and
  - the confidential, anonymous submission by employees of Rock of concerns regarding questionable accounting or auditing matters.
- i. Review and approve Rock's hiring policies regarding partners and employees and former partners and employees of the present and former external auditors of Rock.
- j. Co-ordinate meetings with the Reserves Committee of the Corporation, the Corporation's senior engineering management, independent evaluating engineers and auditors as required to address matters of mutual concern in respect of the Corporation's evaluation of petroleum and natural gas reserves.

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

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

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

1. 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 be entitled to a second or casting vote.
2. The Chair will preside at all meetings of the Committee, unless the Chair is not present, in which case the members of the Committee that are present will designate from among such members the Chair for purposes of the meeting.
3. A quorum for meetings of the Committee will be a majority of its members, and the rules for calling, holding, conducting and adjourning meetings of the Committee will be the same as those governing the Board unless otherwise determined by the Committee or the Board.
4. Meetings of the Committee should be scheduled to take place at least four times per year. Minutes of all meetings of the Committee will be taken. The Chief Financial Officer will attend meetings of the Committee, unless otherwise excused from all or part of any such meeting by the Chairman.
5. The Committee shall meet at the end of or during each meeting without members of management being present.
6. The Committee will meet with the external auditor at least once per year (in connection with the preparation of the year-end financial statements) and at such other times as the external auditor and the Committee consider appropriate.
7. Agendas, approved by the Chair, will be circulated to Committee members along with background information on a timely basis prior to the Committee meetings.

8. The Committee may invite such officers, directors and employees of the Corporation as it sees fit from time to time to attend at meetings of the Committee and assist in the discussion and consideration of the matters being considered by the Committee.
9. Minutes of the Committee will be recorded and maintained and circulated to directors who are not members of the Committee or otherwise made available at a subsequent meeting of the Board.
10. The Committee may retain persons having special expertise and may obtain independent professional advice to assist in fulfilling its responsibilities at the expense of the Corporation.
11. Any members of the Committee may be removed or replaced at any time by the Board and will cease to be a member of the Committee as soon as such member ceases to be a director. The Board may fill vacancies on the Committee by appointment from among its members. If and whenever a vacancy exists on the Committee, the remaining members may exercise all its powers so long as a quorum remains. Subject to the foregoing, following appointment as a member of the Committee, each member will hold such office until the Committee is reconstituted.
12. Any issues arising from these meetings that bear on the relationship between the Board and management should be communicated to the Chairman of the Board by the Committee Chair.