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rockenergy INC.

ARLS
12-31-07

Annual Information Form

Year Ended December 31, 2007

March 12, 2008

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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	The natural gas storage facility located at Suffield, Alberta
API	American Petroleum Institute
°API	an indication of the specific gravity of crude oil measured on the API gravity scale. Liquid petroleum with a specified gravity of 28° API 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^3	cubic metres
MBOE	1,000 barrels of oil equivalent
Mcfe	million cubic feet 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)
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, except as required by applicable law.

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 7, 2008 evaluating the crude oil, natural gas liquids and natural gas reserves of the Corporation as at December 31, 2007;

"**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;

"**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; and

"**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 800, 607 – 8th Avenue S.W., Calgary, Alberta, T2P 0A7 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). As Rock grows, the Corporation intends to expand operations in each of its core areas as well as develop additional core areas.

Rock intends to evaluate acquisitions, both properties and corporate, in its target core areas to compliment future internal operations and potentially add a new core area. 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 was Rock Energy.

On September 28, 2007, the Corporation acquired all of the shares of Greenbank Energy Ltd. ("**Greenbank**") pursuant to a plan of arrangement under the *Business Corporations Act* (Alberta). Immediately following this Acquisition, on September 28, 2007, the Corporation amalgamated with its then wholly-owned subsidiary Greenbank. Following this amalgamation 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, 2007.

Plan Category	Number of securities to be issued upon exercise of outstanding options, warrants and rights (a)	Weighted average exercise price of outstanding options, warrants and rights (b)	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a)) (c)
Equity compensation plans approved by securityholders	2,307,822	$3.42	279,942(1)
Equity compensation plans not approved by securityholders	-	-	-
Total	2,307,822	$3.42	279,942(1)

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 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. 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 contributed to the loss.

During the year ended 2002, Medbroadcast continued the development and operation of 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.

In the third quarter of 2006 the Corporation in separate transactions divested four property areas (Wild River, Highland/Hudson, Cherill and Chestermere) as part of its stated goal of rationalizing its property base. Approximately 820 boe per day of production (approximately 100% natural gas) and 1.4 million boe of proven plus probable reserves (as evaluated by GLJ effective December 31, 2007) were sold in the transactions (collectively the "**Dispositions**"). The proceeds of $30.8 million were used to repay bank indebtedness.

On September 28, 2007, the Corporation completed a private placement to ARC Energy Fund 5 ("**ARC 5**") (the "**Private Placement**") and issued 2,998,623 common shares of the Corporation at a price of $4.05 per share for gross proceeds of approximately $12.1 million.

On September 28, 2007, immediately following the Private Placement, the Corporation acquired all of the outstanding shares of Greenbank (the "**Greenbank Acquisition**") pursuant to a plan of arrangement (the "**Plan of Arrangement**") under the *Business Corporations Act* (Alberta). Pursuant to the Plan of Arrangement, Rock paid to Greenbank Shareholders aggregate consideration of $24.0 million consisting of the issuance of an aggregate 3,143,167 common shares and cash consideration in an amount equal to the gross proceeds of approximately $12.1 million which was received from ARC 5 pursuant to the Private Placement. The properties acquired through the Plan of Arrangement are located in Alberta producing approximately 500 boe per day at the time of the acquisition and are predominately natural gas focused. The acquisition also included approximately 26,000 net (75,000 gross) acres of undeveloped land. The largest and most significant producing property is located in Elmworth, Alberta (31% average working interest) which at the time of the acquisition consisted of a large contiguous land block totalling over 73,600 gross acres and 20 producing wells. Other properties include:

- Kakwa, Alberta (36% average working interest);
- Teepee, Alberta (100% working interest); and
- Edson/Windfall, Alberta (62% average working interest).

In connection with these transactions, on September 28, 2007 Matt Brister resigned as a director of the Corporation and Malcolm Adams, the Vice President of ARC Financial Corp., joined the Board of Directors of the Corporation.

SIGNIFICANT ACQUISITIONS

There were no significant acquisitions 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 Greenbank Acquisition. The Corporation filed a Business Acquisition Report (Form 51-102F4) dated November 23, 2007 in respect of the Greenbank Acquisition on SEDAR at www.sedar.com.

RECENT DEVELOPMENTS

The Corporation commenced drilling 2 (2.0 net) wells late in December 2007 at its Saxon property in the West Central core area. These wells have been completed and tested at combined rates exceeding 7 mmcf per day with over 20 Bbls per MMcf/d of condensate. Rock is working to tie these wells in to a third party processing facility, and expects the wells to come on stream by June 2008 at an initial combined rate of 4-6 MMcf/d. This represents a very significant exploration success for the company and with the infrastructure now being installed it allows Rock to proceed with 2 to 4 more drilling locations in the winter of 2008/09.

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 net capital of $53.7 million for the year ended December 31, 2007 which included $28.1 million for the Greenbank Acquisition (based on the amount of the purchase price allocated to property, plant and equipment), $1.0 million for leasehold improvements for the Corporation's new offices and office equipment and $24.5 million on Rock's exploration and development operations primarily in the Plains and West Central core areas. Of the $24.5 million noted above, 21% was spent on acquiring land ($3.7 million) and seismic ($1.4 million). Rock drilled 10 (9.9 net) wells in its Plains core area, 6 (2.3 net) wells in the West Central core area, and re-completed 22 (17.5 net) wells in 2007, which along with related tie-in and facility capital accounted for 71% of spending or $17.4 million. Of the drilled wells, 8 (8.0 net) are successful heavy oil wells, 6 (3.1 net) are successful gas wells, and 2 (1.1 net) were dry generating a net success rate of 91%. All of the successful heavy oil wells were completed and equipped in 2007. Of the gas wells, 1 (0.9 net) was brought on production during 2007 and the remaining 5 (2.2 net) wells are expected to be tied in during the first half of 2008. Of the re-completion operations, 16 (15.6 net) were Rock operated of which 14 (14.0 net) were in our heavy oil operations. The heavy oil recompletions generally included adding additional perforations and commingling the production or suspending a lower formation and completing in an upper formation. The other 2 (1.6 net) Rock operated recompletions were successful and both are currently on production. Of the 6 (1.9 net) non-operated recompletions 4 (1.2 net) are currently on production with the remaining 2 (0.6 net) shut-in. Rock capitalizes certain salary and related costs associated with exploration and development which accounted for 8% ($2.0 million) of exploration and development capital spending for 2007.

Rock's Board of Directors has approved a $30 million capital budget for 2008 directed primarily at the Plains and West Central core areas. This budget contemplates drilling 18 to 22 wells for approximately $26 million, acquiring land and seismic for $2.4 million, and capitalized administrative costs of $1.5 million. 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 including $7 million related to the Saxon property. Under this program, new production is expected to come on stream from two (typically oil wells) to six months (typically gas wells) after drilling has been completed. The budget is weighted about 75% to the West Central core area and about 25% to the Plains core area.

Principal Properties

The following is a description of the Corporation's oil and natural gas properties as at December 31, 2007. Unless otherwise specified, gross and net acres and well count information are as at December 31, 2007.

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 and 4 (2.8 net) producing gas wells with an average working interest in production of 94%. 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 it 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 1 (0.3 net) gas wells) and its facility through a contract operator. The natural gas production comes from the Edmonton, Pekisko, 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.

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

Rock owns 31,005 (24,626 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 36 (36.0 net) producing heavy oil wells, 1 (0.94 net) producing gas well, 1 (1.0 net) standing gas well, 14 (14.0 net) shut-in oil wells and no disposal wells. Rock's average working interest in production is 99%. The heavy oil wells have been drilled every year beginning in 2004 with most of the production coming on since late 2005. These wells are primarily producing from the Sparky formation. Production is processed at 100% owned well site batteries and then trucked to a third party terminal for sale. Gas production is tied into a 93.75% owned gathering lines which tie in to third party pipelines and processing facilities where the gas is sold. Management expects additional drilling in 2008.

West Central Core Area (deep basin Alberta)

Musreau, Alberta

The Corporation's interests in the Musreau area includes 12 (2.2 net) producing natural gas wells, 1 (1.0 net) natural gas well to be tied-in, and no shut-in, producing oil or disposal wells with an average working interest in production of 13%. The gas wells have been drilled every year beginning in the second half of 2004 and produce from the Fahler, Cadomin and Bluesky formations. The wells are non-operated, except for 2 (1.8 net) gas wells, of which 1 (0.8 net) was tied-in in the first quarter of 2008 to recently expanded third party facilities and 1 (1.0 net) is expected to be tied-in during the second quarter of 2008. Gas is gathered and processed at third party plants in the area. The Corporation owns 9,280 (2,134 net) acres of land in the area. Management expects additional drilling in 2008.

Kakwa, Alberta

The Corporation's interests in the Kakwa area includes 2 (0.7 net) natural gas wells, 2 (0.6 net) producing oil wells and no shut-in or disposal wells. The gas wells were drilled in 2007 and came on production in the first quarter of 2008. Production is gathered and processed at a third party facility along with gas from the Musreau area. Rock owns 6,400 (2,560 net) acres in the area with extensive 2D and 3D seismic coverage. Additional drilling is expected to commence late in 2008.

Kaybob, Alberta

The Kaybob area includes Rock's Saxon, Tony Creek and Waskahigan properties. The Corporation's interests in the Kaybob area includes 9 (1.3 net) producing natural gas wells, 9 (3.7 net) standing or shut-in natural gas wells and no shut-in, producing oil or disposal wells. The standing natural gas wells were drilled at Saxon and Tony Creek in late 2007 and early 2008 and are expected to be on production by June of 2008 as gathering infrastructure is put in place. Production will be processed at a third party facility. Rock owns 12,160 (6,003 net) acres in the area with 2D and 3D seismic coverage. Additional drilling is expected to commence late in 2008.

Elmworth, Alberta

Rock owns 71,358 (22,181 net) acres of land in the Elmworth area of Alberta, with 2D and 3D seismic coverage. As of the date hereof, the property includes 30 (8.2 net) producing natural gas wells and 17 (4.9 net) shut-in natural gas wells. No disposal or injection wells are located in this area. Rock's average working interest in production for the area is 33%. Production is predominately sweet natural gas which is processed through company and third party facilities. The area has established gathering and processing infrastructure. Rock has a 37.5% interest in a sweet natural gas compressor that ties into the Conoco Elmworth plant and a 10% interest in a compressor capable of processing sour natural gas tied in to the Wembley and Sexsmith plants. The natural gas production primarily comes from the Bluesky and Nikanassin formations. Rock does not own rights to all the zones on these lands so other companies also have wells on these lands. Management expects further drilling in this area in 2008.

Niton, Alberta

The Corporation's interest in the Niton area includes 6 (2.3 net) oil wells, 1 (0.4 net) natural gas well and no shut-in wells or disposal wells. Oil production comes from the Rock Creek formation and is non-operated. Rock participated in 2 (0.7 net) wells in 2006 and both were brought on production in 2006. The Corporation owns 2,881 (1,108 net) acres in the area.

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 7, 2008. The effective date of the Statement is December 31, 2007 and the preparation date of the Statement is March 3, 2008.

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, 2007 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 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 (Forecast Prices and Costs)

SUMMARY OF OIL AND GAS RESERVES
AND NET PRESENT VALUES OF FUTURE NET REVENUE
as of December 31, 2007
FORECAST PRICES AND COSTS

	RESERVES							
	LIGHT AND MEDIUM OIL		HEAVY OIL		NATURAL GAS		NATURAL GAS LIQUIDS	
RESERVES CATEGORY	Gross (Mbbl)	Net G (Mbbl)	ross (Mbbl)	Net G (Mbbl)	ross (MMcf)	Net (MMcf)	Gross (Mbbl)	Net (Mbbl)
PROVED								
Developed Producing	323	278	1,919	1,588	7,230	5,647	99	68
Developed Non-producing	60	55	124	97	5,440	4,484	91	66
Undeveloped	0	0	232	183	2,047	1,616	17	12
TOTAL PROVED	383	333	2,275	1,868	14,717	11,747	207	146
PROBABLE	189	161	1,489	1,190	12,960	10,174	152	105
TOTAL PROVED PLUS PROBABLE	572	494	3,764	3,059	27,677	21,921	360	251

	NET PRESENT VALUES OF FUTURE NET REVENUE										
	BEFORE INCOME TAXES DISCOUNTED AT (%/year)					AFTER INCOME TAXES DISCOUNTED AT (%/year)					UNIT VALUE BEFORE INCOME TAX DISCOUNTE D AT 10%/YEAR
RESERVES CATEGORY	0 (M$)	5 (M$)	10 (M$)	15 (M$)	20 (M$)	0 (M$)	5 (M$)	10 (M$)	15 (M$)	20 (M$)	($/BOE)/ ($/Mcfe)
PROVED											
Developed Producing	95,480	82,458	73,339	66,361	60,844	95,480	82,548	73,339	66,361	60,844	25.50/4.25
Developed Non-Producing	29,247	24,258	20,840	18,304	16,333	24,015	20,447	17,923	15,998	14,469	21.59/3.60
Undeveloped	6,439	4,508	3,106	2,058	1,254	4,623	2,948	1,754	875	211	6.70/1.12
TOTAL PROVED	131,166	111,314	97,285	86,722	78,431	124,118	105,943	93,016	83,234	75,524	22.60/3.77
PROBABLE	94,553	70,100	55,135	45,009	37,702	69,520	51,177	39,998	32,469	27,063	17.49/2.92
TOTAL PROVED PLUS PROBABLE	225,719	181,414	152,420	131,731	116,133	193,639	157,121	133,014	115,703	102,587	20.44/3.41

TOTAL FUTURE NET REVENUE
(UNDISCOUNTED)
as of December 31, 2007
FORECAST PRICES AND COSTS

RESERVES CATEGORY	REVENUE (M$)	ROYALTIES (M$)	OPERATING COSTS (M$)	DEVELOPMENT AND RECLAMATION COSTS (M$)	WELL ABANDONMENT AND RECLAMATION COSTS (M$)	FUTURE NET REVENUE BEFORE INCOME TAXES (M$)	INCOME TAXES (M$)	FUTURE NET REVENUE AFTER INCOME TAXES (M$)
Proved Reserves	273,171	49,299	74,184	14,473	4,050	131,166	7,047	124,118
Proved Plus Probable Reserves	478,625	89,845	125,905	31,855	5,302	225,719	32,081	193,639

FUTURE NET REVENUE
BY PRODUCTION GROUP
as of December 31, 2007
FORECAST PRICES AND COSTS

RESERVES CATEGORY	PRODUCTION GROUP	FUTURE NET REVENUE BEFORE INCOME TAXES [1] (discounted at 10%/year) (MM$)	UNIT VALUE ($/BOE)/($Mcfe)
Proved Reserves	Light and Medium Crude Oil[2]	12,857	28.93/4.82
	Heavy Oil	44,521	23.18/3.86
	Natural Gas[3]	39,907	20.57/3.43
	Non-Conventional Oil and Gas Activities	0	0/0
	Total	97,285	22.60/3.77
Proved Plus Probable Reserves	Light and Medium Crude Oil[2]	17,852	27.20/4.53
	Heavy Oil	67,872	21.64/3.61
	Natural Gas[3]	66,695	18.21/3.03
	Non-Conventional Oil and Gas Activities	0	0/0
	Total	152,420	20.44/3.41

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 certainly.

  (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% probability that the quantities actually recovered will equal or exceed the estimated proved reserves; and

(b) at least a 50% 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, 2007, 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, 2007
FORECAST PRICES AND COSTS

	OIL				NATURAL GAS	NATURAL GAS LIQUIDS					
Year	WTI Cushing Oklahoma ($US/Bbl)	Edmonton Par Price 40° API ($Cdn/Bbl)	Cromer 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 ($Cdn/Bbl)	INFLATION RATES(1) %/Year	EXCHANGE RATE(2) ($US/$Cdn)
Forecast											
2008	92.00	91.10	79.26	54.02	6.75	92.92	58.30	72.88	22.73	2	1.00
2009	88.00	87.10	75.78	51.61	7.55	88.84	55.74	69.68	25.49	2	1.00
2010	84.00	83.10	72.30	49.19	7.60	84.76	53.18	66.48	25.66	2	1.00
2011	82.00	81.10	70.56	47.98	7.60	82.72	51.90	64.88	25.66	2	1.00
2012	82.00	81.10	70.56	47.98	7.60	82.72	51.90	64.88	25.66	2	1.00
2013	82.00	81.10	70.56	49.04	7.60	82.72	51.90	64.88	25.66	2	1.00
2014	82.00	81.10	70.56	50.09	7.80	82.72	51.90	64.88	26.35	2	1.00
2015	82.00	81.10	70.56	51.15	7.97	82.72	51.90	64.88	26.94	2	1.00
2016	82.02	81.12	70.57	52.21	8.14	82.74	51.91	64.89	27.52	2	1.00
2017	83.66	82.76	72.00	53.29	8.31	84.42	52.97	66.21	28.11	2	1.00
2018	85.33	84.42	73.44	54.36	8.48	86.11	54.03	68.20	28.67	2	1.00
Thereafter	+2%/year	+2%/year	+2%/year	+2%/year	+2%/year	+2%/year	+2%/year	+2%/year	+2%/year	2	1.00

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, 2007, were $6.96/Mcf for natural gas, $70.69/Bbl for light and medium crude oil, $41.18/Bbl for heavy crude oil and $60.00/Bbl for natural gas liquids.

4. **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 Proved Reserves ($000)	Proved Plus Probable Reserves ($000)
2008	11,217	19,618
2009	3,231	11,792
2010	0	0
2011	0	0
2012	0	0
Thereafter	25	445
Total Undiscounted	14,473	31,855
Total Discounted at 10%	13,502	29,099

The Corporation expects to have sufficient internally generated cash flow and/or available credit facilities to finance the future development costs noted above.

5. 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.**

6. The forecast price and cost assumptions assume the continuance of current laws and regulations.

7. 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

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

	LIGHT AND MEDIUM OIL			HEAVY OIL			ASSOCIATED & NON-ASSOCIATED GAS			NATURAL GAS LIQUIDS		
FACTORS	Gross Proved (Mbbl)	Gross Probable (Mbbl)	Gross Proved Plus Probable (Mbbl)	Gross Proved (Mbbl)	Gross Probable (Mbbl)	Gross Proved Plus Probable (Mbbl)	Gross Proved (MMcf)	Gross Probable (MMcf)	Gross Proved Plus Probable (MMcf)	Gross Proved (Mbbl)	Gross Probable (Mbbl)	Gross Proved Plus Probable (Mbbl)
December 31, 2006	413	175	588	2,705	1,594	4,299	7,507	6,084	13,591	119	64	183
Discoveries	0	0	0	0	0	0	741	373	1,114	19	9	28
Extensions and Improved Recovery	0	0	0	378	154	532	2,245	1,808	4,053	53	32	85
Technical Revisions	7	(10)	(3)	(359)	(258)	(617)	472	(399)	73	(3)	(5)	(9)
Acquisitions	45	24	69	0	0	0	5,289	5,094	10,383	45	54	98
Dispositions	0	0	0	0	0	0	0	0	0	0	0	0
Economic Factors												
Production	(81)	0	(81)	(450)	0	(450)	(1,536)	0	(1,536)	(26)	0	(26)
December 31, 2007	383	189	572	2,275	1,489	3,764	14,717	12,960	27,677	207	153	360

Notes:

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

(2) Figures may not add due to rounding.

Additional Information Relating to Reserves Data

Undeveloped Reserves

The following tables set forth the proved undeveloped reserves and the probable undeveloped reserves, each by product type, attributed to the Corporation's assets for the years ended December 31, 2007, 2006 and 2005 and, in the aggregate, before that time based on forecast prices and costs.

Proved Undeveloped Reserves

Year	Light and Medium Oil (Mbbl)		Heavy Oil (Mbbl)		Natural Gas (MMcf)		NGLs (Mbbl)	
	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End
Prior thereto	-	-	-	-	-	-	-	-
2005	-	-	33	33	-	-	-	-
2006	-	-	47	80	-	-	-	-
2007	-	-	151	232	2,047	2,047	17	17

Probable Undeveloped Reserves

Year	Light and Medium Oil (Mbbl)		Heavy Oil (Mbbl)		Natural Gas (MMcf)		NGLs (Mbbl)	
	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End
Prior thereto	-	-	41	41	220	220	-	-
2005	-	-	17	58	-	220	-	-
2006	-	-	507	565	1,685	1,905	16	16
2007	4	4	270	836	3,151	5,055	23	39

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 expected to be developed within the next two years of the effective date.

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, 2007, which forms part of the Corporation's 2007 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, 2007.

	Oil Wells				Natural Gas Wells			
	Producing		Non-Producing		Producing		Non-Producing	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Alberta	69	44.8	21	9.8	77	22.1	44	15
British Columbia	1	0.4	0	0	3	1.7	5	1.1
Saskatchewan	18	13.2	7	6.5	2	1.9	0	0
Total	88	58.4	28	16.3	82	25.6	49	16.1

Properties with no Attributable Reserves

The following table sets out the Corporation's developed and undeveloped land holdings as at December 31, 2007.

	Developed Acres		Undeveloped Acres		Total Acres	
	Gross	Net	Gross	Net	Gross	Net
Alberta	77,791	27,016	123,429	53,303	201,040	80,319
British Columbia	7,374	2,964	5,404	2,026	12,778	4,990
Saskatchewan	2,716	2,425	6,416	6,389	9,132	8,814
Total	87,882	32,406	135,069	61,718	222,951	94,123

Of the Corporation's undeveloped land, rights to explore, develop and exploit 31,775 (9,152 net) acres expire by December 31, 2008. 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 200 (120.3 net) wells totalling $4.1 million (undiscounted) and 236 (138.8 net) wells totalling $5.3 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 $1.2 million undiscounted is the estimated cost to abandon and reclaim facilities and additional non-reserve wells 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 $0.50 million in abandonment or reclamation expenses in the next three fiscal years to abandon and reclaim 24 (14 net) wells, which are not included in the GLJ Report.

Tax Horizon

As at December 31, 2007, the Corporation has approximately $105.8 million of tax pools, of which $41.7 million are Canadian Exploration expense pools, $28.5 million are Canadian Development expense pools and $14.5 million are non-capital losses, therefore the Corporation does not expect to pay income taxes in 2008.

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, 2007:

	($'000)
Land acquisition costs	3,723
Seismic acquisition costs	1,359
Exploration drilling and completion costs	7,252
Development drilling and completion costs	8,547
Facility and equipment costs	1,678
Acquisitions(1)	28,127
Capitalized G&A	2,004
Office Equipment	1,012
Total	53,702

Note:
(1) Represents the amount allocated to property, plant and equipment from the purchase price.

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, 2007:

	Gross	Net
Heavy Oil	8	8.0
Light and Medium Oil	0	0.0
Natural Gas	6	3.1
Service	0	0.0
Dry	2	1.1
Total:	16	12.2

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, 2008 which is reflected in the estimate of future net revenue disclosed in the Forecast Prices and Costs table 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)
Total Proved	178	1,575	8,643	129	3,321
Total Probable	20	289	2,519	33	762
Total Proved Plus Probable	198	1,864	11,162	162	4,083

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:

	Quarter Ended							
	2007				2006			
(6:1)	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Average Daily Production[1]								
Light & Medium Crude Oil (Bbls/d)	206	195	215	243	206	167	161	183
Heavy Crude Oil (Bbls/d)	1,323	1,079	1,224	1,150	1,168	835	478	679
Gas (Mcf/d)	6,372	3,669	3,129	3,852	3,528	3,350	8,964	9,946
NGLs (Bbls/d)	81	79	75	79	42	53	57	74
Combined (BOE/d)	2,672	1,965	2,036	2,114	2,004	1,613	2,190	2,594
Average Price Received								
Light & Medium Crude Oil ($/Bbl)	81.66	75.29	65.10	62.39	57.77	70.63	70.79	60.61
Heavy Crude Oil ($/Bbl)	42.56	44.17	39.50	38.48	34.86	47.94	48.99	24.84
Gas ($/Mcf)	6.64	5.70	7.75	8.10	7.45	6.41	6.41	7.76
NGLs ($/Bbl)	67.81	61.47	57.58	52.65	65.47	56.86	71.46	54.31
Combined ($/BOE)	45.26	44.85	44.66	44.84	40.73	47.30	44.01	42.08
Royalties Paid								
Light & Medium Crude Oil ($/Bbls)	13.54	9.64	12.20	9.58	9.92	8.93	6.73	14.53
Heavy Crude Oil ($/Bbl)	8.71	8.74	7.55	6.60	7.23	9.96	9.38	6.07
Gas ($/Mcf)	0.91	1.41	1.78	1.94	1.26	(0.65)	1.40	2.40
NGLs ($/Bbl)	22.42	19.48	18.07	11.46	19.34	15.50	26.45	15.72
Combined ($/BOE)	8.21	9.18	9.23	8.66	7.88	5.27	8.97	12.26
Transportation Expense	0.54	0.50	0.47	0.59	0.45	0.44	0.42	0.34
Operating Expenses [3]								
Light & Medium Crude Oil ($/Bbl) [3]	9.93	10.11	10.18	12.33	11.57	14.65	8.45	11.13
Heavy Crude Oil ($/Bbl)	13.61	13.37	12.54	12.02	14.32	10.81	16.07	11.10
Gas ($/Mcf) [3]	1.66	1.69	1.70	2.05	1.93	2.44	1.41	1.85
NGLs ($/Bbl) [3]	9.93	10.11	10.18	12.33	11.57	14.65	8.45	11.13
Combined ($/BOE) [3]	11.75	11.90	11.60	12.16	13.18	12.69	10.13	11.21
Netback Received[2]								
Light & Medium Crude Oil ($/Bbl)	56.65	54.10	41.31	39.06	36.07	46.19	54.62	34.21
Heavy Crude Oil ($/Bbl)	20.24	22.06	19.42	19.87	13.31	27.17	23.55	7.67
Gas ($/Mcf)	3.90	2.41	4.06	3.87	4.08	4.45	3.52	3.43
NGLs ($/Bbl)	35.46	31.87	29.33	28.86	34.47	24.40	36.56	27.51
Combined ($/BOE)	24.76	23.27	23.36	23.43	19.22	28.90	24.49	18.27

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, 2007 was 10% light quality crude oil (32° API or greater), 54% heavy crude oil and 4% natural gas and liquids.

For the year ended December 31, 2007, approximately 70% of the Corporation's gross revenue was derived from crude oil production (including natural gas liquids) and 30% 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		
	High	Low	Volume
2007			
January	3.00	2.67	399,864
February	3.69	2.91	788,943
March	3.59	3.20	184,792
April	3.85	3.31	772,212
May	4.25	3.73	529,712
June	4.20	4.00	1,071,244
July	4.10	4.00	848,182
August	4.00	3.25	125,150
September	3.65	3.30	200,312
October	3.30	2.16	732,842
November	2.90	2.05	871,965
December	2.99	2.30	509,208
2008			
January	2.90	2.05	503,133
February	3.39	2.36	933,181
March (1-11)	3.15	2.75	58,431

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[(4)] 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
Jeffrey G. Campbell Calgary, Alberta	Vice President, Operations and Chief Operating Officer	Vice President, Operations and Chief Operating Officer of Rock since November 2007. From January 2002 to August 2007, Vice President, Production, then Executive Vice President (Country Manager) of Seneca Energy Canada Inc. (the Canadian subsidiary of a public energy utility). From July 2001 to December 2001 District Manager of Husky Energy Inc. (a public oil and gas company). From April 1997 to July 2001 Vice President, Production of Avid Oil and Gas Ltd. (a public oil and gas company).	N/A
Arezki Ioughlissen Calgary, Alberta	Vice President, Exploration	Vice President, Exploration of Rock since November 2007. From December 2004 to October 2007 Chief Geophysicist of Rock. From May 2002 to December 2004 Geophysical Advisor of Vintage Petroleum Canada Inc. (the Canadian subsidiary of a public oil and gas company). From April 2001 to May 2002 Senior Geophysicist of Rio Alto Exploration (a public oil and gas company). From January 1997 to March 2001 Senior Geophysicist then Chief Geophysicist of Fletcher Challenge Energy Canada (the Canadian subsidiary of a public oil and gas company)..	N/A
Grant A. Zawalsky Calgary, Alberta	Corporate Secretary	Partner of Burnet, Duckworth & Palmer LLP (lawyers)	N/A
Stuart G. Clark(1)(2)(3) Calgary, Alberta	Director	Independent businessman since November 2001. From November 1998 to November 2001 Vice President Finance and CFO of Storm Energy Inc. (a public oil and gas company). 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(1)(4) 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
Malcolm Adams(3)(4) Calgary, Alberta	Director	Since October 2001 Vice President of ARC Financial Corp. (private equity firm). From May 1997 to October 2001 Senior Exploration Engineer of ARC Resources Management Ltd. (manager of ARC Energy Trust, a public oil and gas trust). From June 1994 to May 1997 Reservior Engineer of Shell Canada Ltd..	September 28, 2007
James K. Wilson(1)(3) 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 12, 2008, the directors and officers of the Corporation, as a group, beneficially owned, or controlled or directed, directly or indirectly, 2,333,490 common shares or approximately 9.0% of the issued and outstanding common shares of the Corporation.

Corporate Cease Trade Orders or Bankruptcies

No director or officer of the Corporation: (a) is, or within 10 years before the date hereof, has been, a director, chief executive officer or chief financial officer of any other issuer that: (i) was subject to an order that was issued while the director or officer was acting in the capacity as director, chief executive office or chief financial officer; or (ii) was subject to an order that was issued after the director or officer ceased to be a director, chief executive officer or chief financial officer and which resulted from an event that occurred while that person was acting in the capacity as director, chief executive officer or chief financial officer; or (b) is, or has been within 10 years before the date hereof, a director or executive officer of any issuer that, while that person was acting in that capacity, or within a year of that person ceasing to act in that capacity, became bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets, 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. For the purposes of paragraph (a) above, "order" means a cease trade order, an order similar to a cease trade order or an order that denied the relevant company access to any exemption under securities legislation that was in effect for a period of more than 30 consecutive days.

No director or executive officer of the Corporation, or to the knowledge of management of the Corporation, a shareholder holding a sufficient number of securities of the Corporation to affect materially the control of the Corporation: (a) is, as at the date hereof, or has been within the 10 years before the date hereof, a director or executive officer of any company (including the Corporation) that, while that person was acting in that capacity, or within a year of that person ceasing to act in that capacity, became bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets, state the fact; or (b) has, within the 10 years before the date hereof, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or become subject to or instituted any proceedings, arrangement or compromise with creditors, or had a receiver, receiver manager or trustee appointed to hold the assets of the director, executive officer or shareholder.

Penalties or Sanctions

No director, 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 directors 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 25 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 $66,040 in 2007 ($61,960 in 2006).

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 $54,356 in 2007 ($24,384 in 2006). The services provided consisted of review of quarterly statements and disclosure and review of acquisition related documents.

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 $31,000 in 2007 ($47,000 in 2006).

LEGAL PROCEEDINGS

There are no legal proceedings which the Corporation or any subsidiary of the Corporation is or was a party to, or of which any of their property is or was the subject of during the most recent completed financial year of the Corporation, 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, or controls or directs, directly or indirectly, more than 10% of the outstanding Common Shares, or any known associate or affiliate of such persons, in any transaction within the last three fiscal years and in any proposed transaction which has materially affected or is reasonably expected to 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 report, valuation, statement or opinion described or included in a filing, or referred to in a filing, made under National Instrument 51-102 by the Corporation during, or 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 report, valuation, statement or opinion prepared by it, at any time thereafter or to be received by them.

KPMG LLP has confirmed that they are independent in accordance with the rules of professional conduct of the Institute of Chartered Accountants.

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 18 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 S.W., 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. 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.

The oil and natural gas industry is subject to environmental regulation pursuant to local, provincial and federal legislation. A breach of such legislation may result in the imposition of fines or issuance of clean up orders in respect of us or our properties. Such legislation may be changed to impose higher standards and potentially more costly obligations on us. Furthermore, management believes the political climate appears to favour new programs for environmental laws and regulation, particularly in relation to the reduction of emissions, and there is no assurance that any such programs, laws or regulations, if proposed and enacted, will not contain emission reduction targets which we cannot meet, and financial penalties or charges could be incurred as a result of the failure to meet such targets. In particular there is uncertainty regarding the Government of Canada's Clean Air Act of 2006. The Clean Air Act proposes to reduce greenhouse gas emissions, however emission targets and compliance deadlines differ from those outlined in the Kyoto Protocol which was ratified by Canada. If passed, the Clean Air Act may have adverse operational and financial implications to the Corporation. See "Industry Conditions – Environmental Regulation".

Provincial emission reduction requirements, such as those proposed in Alberta's Bill 37 Climate Change and Emissions may require the reduction of emissions or emissions intensity of our operations and facilities. The direct or indirect costs of these regulations may adversely and materially affect our business.

Canada is a signatory to the United Nations Framework Convention on Climate Change and in December 2002 the Government of Canada ratified the Kyoto Protocol and it became legally binding on February 16, 2005. This protocol calls for Canada to reduce its greenhouse gas emissions to six per cent below 1990 levels during the period between 2008 and 2012. Our exploration and production facilities and other operations and activities emit greenhouse gases that may subject us to legislation regulating emissions of greenhouse gases. The Government of Canada has put forward a Climate Change Plan for Canada which suggests further legislation will set greenhouse gases emission reduction requirements for various industrial activities, including oil and gas exploration and production. There has been much public debate with respect to Canada's ability to meet these targets and the Government's strategy or alternative strategies with respect to climate change and the control of greenhouse gases. Implementation of strategies for reducing greenhouse gases whether to meet the limits required by the Kyoto Protocol or as otherwise determined, could have a material impact on the nature of oil and natural gas operations, including ours. Given the evolving nature of the debate related to climate change and the control of greenhouse gases and resulting requirements, it is not possible to predict either the nature of those requirements or the impact on us and our operations and financial condition.

Although we believe that we are in material compliance with current applicable environmental regulations, no assurance can be given that environmental laws will not result in a curtailment of production or a material increase in the costs of production, development or exploration activities or otherwise adversely affect our financial condition, results of operations or prospects. Future changes in other environmental legislation could occur and result in stricter standards and enforcement, larger fines and liability, and increased capital expenditures and operating costs, which could have a material adverse effect on our financial condition or results of operations. See "Industry Conditions – Environmental Regulation".

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

The Corporation's oil and natural gas properties, wells and facilities could be subject to a terrorist attack. If any of the Corporation's properties, wells or facilities are the subject of terrorist attack it could have a material adverse effect on the Corporation. The Corporation will not have insurance to protect against the risk from terrorism.

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

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 strengthened recently, 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. Approximately 54% of the Corporation's 2007 annual production is heavy oil which receives a lower price than lighter grades of oil. 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 and operation. 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 (i.e. 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 (other than propane, butane and ethane) 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^3/day) must be made pursuant to an NEB order. Any natural gas export to be made pursuant to a contract of longer duration (to a maximum of 25 years) or 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.

The Canadian federal corporate income tax rate levied on taxable income is 22.1% effective January 1, 2007 for active business income including resource income. With the elimination of the corporate surtax effective January 1, 2008 and other rate reductions introduced in the October 2007 Economic Statement and Notice of Ways and Means Motion, 2006 Federal Budget, the federal corporate income tax rate will decrease to 19% in three steps: 20.5% on January 1, 2008, 20% on January 1, 2009 and 19% on January 1, 2010.

Alberta

In Alberta, companies are granted the right to explore, produce and develop petroleum and natural gas resources in exchange for royalties, bonus bid payments and rents. Currently, the amount of royalties that are payable is influenced by the oil production, diversity of the oil, and the vintage of the oil. Originally, the vintage classified oil as "new oil" and "old oil" depending on when the oil pools were discovered. If the pool was discovered prior to March 31, 1974 it is considered "old oil" and if it was discovered after March 31, 1974 and before September 1, 1992, it is considered "new oil". The

Alberta government introduced in 1992 a Third Tier Royalty with a base rate of 10% and a rate cap of 25% for oil pools discovered after September 1, 1992. The new oil royalty reserved to the Crown has a base rate of 10% and a rate cap of 30%. The old oil royalty reserved to the Crown has a base rate of 10% and a rate cap of 35%.

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

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

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

On October 25, 2007, the Alberta government released a report titled "The New Royalty Framework" (the "**Report**") containing the government's proposals for Alberta's new royalty regime (the "**Proposed Royalty Regime**"), which is scheduled to take effect on January 1, 2009. The Proposed Royalty Regime includes the following features:

- new, simplified royalty formulas for conventional oil and natural gas that will operate on sliding scales that are determined by commodity prices, well productivity and measured depths of natural gas wells. The formulas eliminate the need for conventional oil and natural gas tiers and several royalty exemption programs;

- a sliding scale will be implemented for oil sands royalty rates ranging from 1% to 9% pre-payout and 25% to 40% post-payout depending on the price of oil;

- the province will exercise its existing right to receive "royalty in kind" on oil sands projects (i.e. raw bitumen delivered to the Crown operated Alberta Petroleum Marketing Commission in lieu of cash royalties);

- the government will ensure that eligible expenditures and definitions of oil sands projects (also known as "ring fence" definition) that determine when a project has reached payout are tightly and clearly defined. Environmental "costs of doing business" will continue to be recognized as eligible expenditures;

- no grandfathering will be implemented for existing oil sands projects; and

- substantial legislative, regulatory and systems updates will be introduced before changes become fully effective in January 2009.

The Report indicated that as the Alberta Government further develops the Proposed Royalty Regime, adjustments may be made to ensure that there are no "unintended consequences" to its decisions. Government officials have subsequently had discussions with a number of stakeholders respecting potential "unintended consequences" and have indicated that they are prepared to work through economic issues related to four categories of wells which might give rise to adjustments; however, as at the date hereof, no further information in respect of potential adjustments to the Proposed Royalty Regime has been announced.

Given that the Proposed Royalty Regime has only recently been announced, it is not possible at this time to determine the full impact of the Proposed Royalty Regime on the Corporation's financial condition and operations, and in particular the extent to which the Proposed Royalty Regime will reduce the Corporation's cash flow, which will in turn reduce the cash otherwise available for distribution by the Corporation to its Shareholders. The Corporation's reserves and the future net revenue associated therewith as contained in the GLJ Report do not reflect the revised royalty rates contemplated by the Proposed Royalty Regime and, after taking the Proposed Royalty Regime into account, such values may be adversely affected. GLJ has prepared high and low sensitivity cases under the Proposed Royalty Regime based on assumptions that all independent consulting firms agreed to use in their evaluations. The low royalty sensitivity case assumes that a heavy oil par price is used in the royalty calculations, solution natural gas royalties are calculated using the same rate and price basis as non-associated natural gas, and the deep natural gas royalty adjustment is applied to all existing and future wells. The high royalty sensitivity case assumes that a light oil par price is used in the royalty calculations for heavy oil, solution natural gas royalties are calculated using the same rate and price basis as non-associated natural gas but restricted to no less than the current royalty rate of 30% on solution natural gas, and the deep natural gas royalty adjustment is applied only to wells drilled after 2008. Under the low royalty sensitivity case, Rock's net present value of future net revenue from proven plus probable reserves before tax discounted at 10% does not change under the low royalty sensitivity case and decreases by approximately 5% under the high royalty sensitivity case.

The Corporation cannot provide any assurance that the Proposed Royalty Regime will be implemented in the form proposed in the Report. If changes are made to the Proposed Royalty Regime before it is implemented by the Alberta government, such changes could be more adverse to the Corporation than the royalty regime proposed in the Report.

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 or 11,450m^3 produced, whichever comes first; and the royalties for third-tier oil are the lowest reflecting the higher costs of exploration and extraction that the producers would incur. The royalty payable on natural gas is determined by a sliding scale based on a reference price, which is the greater of the amount obtained by the producer, and a prescribed minimum price. However, when the reference price is below the select price (a parameter used in the royalty rate formula), the royalty rate is fixed. As an incentive for the production and marketing of natural gas, which may have been flared, natural gas produced in association with oil has a lower royalty then 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.

On February 27, 2007 the Government of British Columbia unveiled the Energy Plan outlining the Province's strategy towards the environment and which includes targeting for zero net greenhouse gas emissions, promoting new investments in innovation, and becoming the world's leader in sustainable environmental management. For this purpose, on December 18, 2007 proposals were sought for applications to the Innovation Clean Energy Fund, in order to attract new technologies that will help solve energy and environmental issues. With regards to the oil and gas industry the objective is to achieve clean energy through conservation and energy efficient practices, whilst competitiveness is advocated in order to attract investment for the development of the oil and gas sector. Among the changes to be implemented are: (i) a new of Net Profit Royalty Program; (ii) the creation of a Petroleum Registry; (iii) the establishment of an infrastructure royalty program (combining roads and pipelines); (iv) the elimination of routine flaring at producing wells; (v) the creation of policies and measures for the reduction of emissions; (vi) the development of unconventional resources such as tight gas and coalbed gas; and (vii) new the Oil and Gas Technology Transfer Incentive Program that encourages the research, development and use of innovative technologies to increase recoveries from existing reserves and promotes responsible development of new oil and gas reserves.

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.

In 1975 the Government of Saskatchewan introduced a Royalty Tax Rebate ("**RTR**") as a response to the federal government disallowing crown royalties and similar taxes to be deducted as a business expense for income tax purposes. As of January 1, 2007 the RTR will be allowed to wind down since the federal government had the initiative to reintroduce the full deduction of provincial resource royalties from federal and provincial income tax.

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

Land Tenure

Crude oil and natural gas located in 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. In 2006, the Alberta Government enacted regulations pursuant to the EPEA to specifically target sulphur oxide and nitrous oxide emissions from industrial operations including the oil and gas industry. In addition, the reduction emission guidelines outlined in the *Climate Change and Emissions Management Amendment Act* came into effect on July 1, 2007. Under this legislation, Alberta facilities emitting more than 100,000 tonnes of greenhouse gases a year must reduce their emissions intensity by 12%. Industries have three options to choose from in order to meet the reduction requirements outlined in this legislation, and these are: (i) by making improvement to operations that result in reductions; (ii) by purchasing emission credits from other sectors or facilities that have emissions below the 100,000 tonne threshold and are voluntarily reducing their emission; or (iii) by contributing to the Climate Change and Emissions Management Fund. Industries can either choose one of these options or a combination thereof. 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.

On January 24, 2008, the Alberta Government announced a new climate change action plan that will cut Alberta's projected 400 million tonnes of emissions in half by 2050. This plan is based on three areas: (i) carbon capture and storage, which will be mandatory for *in situ* oil sand facilities that use heavy fuels for steam generation; (ii) energy conservation and efficiency; and (iii) greening production through increased investment in clean energy technology, including supporting research on new oil sands extraction processes, as well as the funding of projects that reduce the cost of separating CO_2 from other emissions supporting carbon capture and storage.

British Columbia's *Environmental Assessment Act* became effective June 30, 1995. This legislation rolls the previous processes for the review of major energy projects into a single environmental assessment process with public participation in the environmental review process.

In December 2002, the Government of Canada ratified the Kyoto Protocol ("**Protocol**"). The Protocol calls for Canada to reduce its greenhouse gas emissions to 6% below 1990 "business-as-usual" levels between 2008 and 2012. Given revised estimates of Canada's normal emissions levels, this target translates into an approximately 40% gross reduction in Canada's current emissions. It remains uncertain whether the Kyoto target of 6% below 1990 emission levels will be enforced in Canada. The Federal Government has introduced legislation aimed at reducing greenhouse gas emissions using a "intensity based" approach, the specifics of which have yet to be determined. Bill C-288, which is intended to ensure that Canada meets its global climate change obligations under the Kyoto Protocol, was passed by the House of Commons on February 14, 2007.

The Federal Government released on April 26, 2007, its Action Plan to Reduce Greenhouse Gases and Air Pollution (the "**Action Plan**"), also known as ecoACTION and which includes the Regulatory Framework for Air Emissions. This Action Plan covers not only large industry, but regulates the fuel efficiency of vehicles and the strengthening of energy standards for a number of energy-using products. The Government of Canada and the Province of Alberta released on January 31, 2008 the final report of the Canada-Alberta ecoENERGY Carbon Capture and Storage Task Force, which recommends among others: (i) incorporating carbon capture and storage into Canada's clean air regulations; (ii) allocating new funding into projects through competitive process; and targeting research to lower the cost of technology.

The Climate Change and Emissions Management Amendment Act, which intends to reduce greenhouse gas emission intensity from large industries came into effect on July 1, 2007. Alberta facilities emitting more than 100,000 tonnes of greenhouse gases a year must reduce their emissions intensity by 12% starting July 1, 2007; if such reduction is not initially possible the companies owning the large emitting facilities will be required to pay $15 per tonne for every tonne above the 12% target. These payments will be deposited into an Alberta-based technology fund that will be used to develop infrastructure to reduce emissions or to support research into innovative climate change solutions. As an alternate option, large emitters can invest in projects outside of their operations that reduce or offset emissions on their behalf, provided that these projects are based in Alberta. Prior to investing, the offset reductions, offered by a prospective operation, must be verified by a third party to ensure that the emission reductions are real.

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

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 15, 2007, which relates to the Annual General Meeting of Shareholders held on May 15, 2007. Additional financial information is contained in the consolidated financial statements of the Corporation for the year ended December 31, 2007 and the Management's Discussion and Analysis contained in the Corporation's Annual Report for the year ended December 31, 2007.

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 800, 607 – 8th Avenue S.W., Calgary, Alberta, T2P 0A7, or by phone at (403) 218-4380, fax at (403) 234-0598 or email at 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, 2007. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2007 using forecast prices and costs.

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

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%, included in the reserves data of the Company evaluated by us for the year ended December 31, 2007, 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) ($'000)			
			Audited	Evaluated	Reviewed	Total
GLJ Petroleum Consultants Ltd.	Corporate Summary March 3, 2008	Canada	$nil	$152,420	$nil	$152,420

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; however, any variations should be consistent with the fact that reserves are categorized according to the probability of their recovery.

Executed as to our report referred to above:

GLJ Petroleum Consultants Ltd.
Calgary, Alberta, Canada
March 6, 2008

ORIGINALLY SIGNED BY
Leonard L. Herchen, 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 are estimates of proved reserves and probable reserves and estimated future net revenues as at December 31, 2007 using forecast prices and costs.

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

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

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

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

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

The Reserves 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:

(d) the content and filing with securities regulatory authorities of Form 51-101F1 containing the reserves data and other oil and gas information;

(e) the filing of Form 51-101F2 which is the report of the independent qualified reserves evaluator on the reserves data; and

(f) the content and filing of this report.

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

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

(signed) "Jeffrey G. Campbell"
Jeffrey G. Campbell
Vice President, Operations and Chief Operating Officer

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

(signed) "Stuart G. Clark"
Stuart G. Clark
Director and Chairman of the Board

March 12, 2008

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.

File No. 82-34785

rockenergy

PRESS RELEASE

Rock Energy 2007 Year End Results

March 12, 2008, Calgary, Alberta: Rock Energy Inc. (TSX:RE) is pleased to report its financial and operating results for the three month and twelve month periods ending December 31, 2007. Today the Company filed its Annual Information Form which includes Rock's reserves data and other oil and gas information for the year ended December 31, 2007 as mandated by National Instrument 51-101 Standards of Disclosure for Oil and Gas Activities of the Canadian Securities Administrators. Copies of Rock's Annual Information Form may be obtained on www.sedar.com or by contacting Rock.

Rock is a Calgary, Alberta, Canada based crude oil and natural gas exploration, development and production company.

During 2007 Rock accomplished the following key goals:

- **Acquired Greenbank Energy Inc.**
  On September 28, 2007 Rock closed the acquisition of Greenbank Energy Inc. for total consideration of $28.1 million plus $0.4 million of allocated capitalized G&A. Rock acquired 1.9 million boe of proved plus probable reserves, 500 boe/d of production (92 percent natural gas), more than 25,000 net acres of undeveloped land and 25-30 drilling locations. This strategic acquisition represented a natural extension of Rock's exploration program in the Deep Basin. It extends our activities northwest from Kaybob, into an area where the stacked Cretaceous gas plays are shallower , drilling costs are lower, gas processing capacity is readily available, and surface operations can be completed year-round (except during spring break-up).

- **Drilling Results**
  In 2007 Rock participated in 16 (12.2 net) wells, resulting in 8 (8.0 net) heavy oil wells, 6 (3.1 net) natural gas wells and 2 (1.1 net) dry and abandoned wells, for a success rate of 91 percent on net wells. Our exploration program established commercial reservoirs at Saxon, Kakwa, and Elmworth. These areas will provide exploitation and development programs for 2008 and 2009. So far in 2008 Rock has drilled 4 (1.98 net) natural gas wells at Saxon, Girouxville, Markerville, and Tony Creek, all successful.

- **Infrastructure Construction**
  A key accomplishment in 2007 was the construction of pipelines, gas plants and compressor stations to tie-in our gas wells at Musreau and Kakwa. This critical infrastructure has been brought on-stream during the first quarter of 2008 and our production is now beginning to increase. These facilities plus the work we are currently doing in the Saxon area improve the profitability of future drilling locations and will speed future tie-ins.

- **Reserves and Net Asset Value**
  Rock has increased total Company reserves by 27 percent on a proved plus probable basis, from 7.3 million boe at year-end 2006 to 9.3 million boe at year-end 2007. Proved reserves were increased by 18 percent over the same timeframe, from 4.5 million boe to 5.3 million boe. All-in finding, development and acquisition (FD&A) costs incurred in 2007 averaged $24.42/boe (proved plus probable). This is higher than we consider acceptable. The reason stems from negative technical revisions at our heavy oil properties and high future capital costs associated with our acquisition of Greenbank and at our newly discovered gas properties in Kakwa and Saxon, which have limited reserve bookings to date. The Company expects to increase reserve bookings as we get more production history from the new wells and the full exploration cycle is completed. Our three-year all-in FD&A cost was $16.35/boe (proved plus probable), which is more representative of true full-cycle costs.

The reserve report by GLJ Petroleum Consultants Ltd. has indicated a reserve value of $152 million (net present value discounted at 10%, before tax) under the existing royalty regime and $145-152 million under an assumed range of Alberta's proposed new royalty regime. Under the proposed royalty regime calculation, Rock's net asset value becomes $4.99-$5.28 per share (basic), assuming year-end debt of $29.1 million, land of 61,718 net acres at the acquired cost of $13.4 million, no value for seismic, and 25.9 million basic shares outstanding.

- **Production Results**
  Rock's daily production in 2007 averaged 2,198 boe/d for the year, and during the fourth quarter we averaged 2,672 boe/d. Although our average production rate for the year was essentially flat (compared to 2006), Rock's 2007 activities laid the foundation for production growth in 2008. The exploration cycle in the Deep Basin can take two to three years, especially when we are dealing with winter-access areas and processing facility limitations. We are now emerging from the exploration cycle and estimate our current daily production to be about 3,000 boe/d – compared to only 2,114 boe/d at this time last year. We expect our production to average 3,400 boe/d this year, a 55 percent increase from 2007.

- **Financial Results**
  In 2007 Rock generated funds from operations of $15.2 million ($0.72 per share) and net income of $561,000 ($0.03 per share). The Company had capital expenditures of $53.7 million, of which $28.1 million was for the Greenbank Energy Inc. acquisition, financed through the issuance of common shares. Total debt was $29.1 million at year-end, against bank lines of $36 million. Our borrowing base is currently being reviewed in light of our 2007 activity, and we expect our bank lines to be increased from $36 million to $38 million, plus a development facility of $6 million.

2008 Capital Program

Rock's Board of Directors has approved an increase to our capital budget from $24 million to $30 million for 2008. The program's goals are to prove up and tie-in the exploration wells at Saxon and Kakwa during the first quarter (which is now underway), drill the heavy oil wells and Elmworth exploitation gas wells during the second and third quarters, and embark on the winter development drilling program at Musreau, Saxon and Kakwa during the fourth quarter. The additional $6 million is required to construct the gathering system and processing facility at Saxon. This strategic infrastructure will allow Rock to expand the development of our program in the area.

This year we aim to drill 18-22 wells, nine of which would be heavy oil wells. These heavy oil wells again will aim to replace natural declines and hold production at 1,300 boe/d, with excess cash flow directed to the West Central core area. This capital program is expected to yield average production of 3,400-3,600 boe/d and an exit rate of 3,900-4,100 boe/d. Cash flow is forecast at $28 million ($1.08 per share), assuming average commodity prices of US$85.00/bbl of WTI oil and $7.25/mcf of AECO natural gas, and a Canada-U.S. dollar exchange rate of par. Under these plans and working assumptions the Company's debt by the end of the first quarter will reach $39 million, but by year end will have dropped to $31.5 million, which would be equal to 1 times fourth quarter annualized cash flow.

Conclusion

In a challenging environment, we find the opportunity. Rock used the opportunities that 2007 presented to set the stage for growth and prosperity in 2008 and beyond. Though our production in 2007 did not grow significantly over 2006, our opportunity base and capability did. We completed the acquisition of Greenbank Energy Inc., capturing a foothold in the Elmworth area with 25-30 drilling locations and transforming ourselves into a larger, more robust operating company. In addition we demonstrated our exploration capabilities in the Alberta Deep Basin through drilling success at Saxon, Kakwa, and Elmworth, plus installed the infrastructure to get these wells on-stream. With a large inventory of drilling locations, a strong management team, and new infrastructure in place Rock is prepared to deliver solid production growth in 2008.

As we look at 2008 we believe the cycle has begun to turn again. Natural gas prices are improving and oil prices are more solid than ever. But the market has evolved. We believe it is important to continue an aggressive growth program that includes acquisitions and grassroots exploration. As the company grows it will be able to attract more support from the market and capture more opportunity to deliver value growth for its shareholders. We are pursuing these opportunities now.

Corporate Summary

	Twelve months ended December 31, 2007	Twelve months ended December 31, 2006	Three months ended December 31, 2007	Three months ended December 31, 2006
Financial				
Oil and natural gas revenue ($000)	$ 36,042	$ 33,156	$ 11,124	$ 7,535
Funds from operations ($000) [1]	$ 15,189	$ 13,867	$ 4,735	$ 2,644
Per share – basic	$ 0.72	$ 0.71	$ 0.18	$ 0.13
– diluted	$ 0.72	$ 0.71	$ 0.18	$ 0.13
Net income (loss) ($000)	$ 561	$ (884)	$ 290	$ (119)
Per share – basic	$ 0.03	$ (0.05)	$ 0.01	$ (0.01)
– diluted	$ 0.03	$ (0.05)	$ 0.01	$ (0.01)
Capital expenditures, net ($000)	$ 53,702	$ 2,004	$ 7,488	$ 6,223

	As at December 31, 2007	As at December 31, 2006
Working capital including bank debt ($000)	$ (29,072)	$ (12,580)
Common shares outstanding (000)	25,878	19,637
Options outstanding (000)	2,308	1,767

	Twelve months ended December 31, 2007	Twelve months ended December 31, 2006	Three months ended December 31, 2007	Three months ended December 31, 2006
Operations				
Average daily production				
Light crude oil *(bbls/d)*	215	179	206	206
Heavy crude oil *(bbls/d)*	1,194	792	1,323	1,168
NGL *(bbls/d)*	79	57	81	42
Natural gas *(mcf/d)*	4,261	6,421	6,372	3,528
Total *(boe/d)*	2,198	2,098	2,672	2,004
Average product prices				
Light crude oil *(Cdn$/bbl)*	$70.69	$ 64.46	$81.66	$ 57.77
Heavy crude oil *(Cdn$/bbl)*	$41.18	$ 38.35	$42.56	$ 34.86
NGL *(Cdn$/bbl)*	$60.00	$ 61.35	$67.81	$ 65.47
Natural gas *(Cdn$/mcf)*	$6.96	$ 7.07	$6.64	$ 7.45
BOE *(Cdn$/boe)*	$44.93	$ 43.27	$45.26	$ 40.73
Operating netback *(Cdn$/boe)*	$23.79	$ 22.21	$24.77	$ 19.22

[1] Funds from operations and funds from operations per share are not terms under generally accepted accounting principles (GAAP), and represent cash generated from operating activities before changes in non-cash working capital. Rock considers it a key measure as it demonstrates the Company's ability to generate the cash necessary to fund future growth through capital investment. Funds from operations may not be comparable with the calculation of similar measures for other companies. Funds from operations per share is calculated using the same share basis which is used in the determination of net income/(loss) per share.

Management's Discussion and Analysis

ROCK ENERGY INC. ("ROCK" OR THE "COMPANY") is a publicly traded energy company engaged in the exploration for and the development and production of crude oil and natural gas, primarily in Western Canada. Rock's corporate strategy is to grow and develop an oil and natural gas exploration and production company through internal operations and acquisitions.

Rock evaluates its performance based on net income, operating netback, funds from operations and finding and development costs. Funds from operations are a measure used by the Company to analyze operations, performance, leverage and liquidity. Operating netback is a benchmark used in the oil and natural gas industry to measure the contribution of the oil and natural gas operations following the deduction of royalties, transportation costs and operating expenses. Finding and development costs are another benchmark used in the oil and natural gas industry to measure the capital costs incurred by the Company to find and bring reserves on-stream.

Rock faces competition in the oil and natural gas industry for resources, including technical personnel and third-party services, and capital financing. The Company is addressing these issues through the addition of personnel with the expertise to develop opportunities on existing lands and to control operating and administrative cost structures. Rock also seeks to obtain the best commodity price available based on the quality of its produced commodities.

The following Management's Discussion and Analysis is dated March 12, 2008 and is management's assessment of Rock's historical, financial and operating results, together with future prospects, and should be read in conjunction with the audited consolidated financial statements of Rock for the 12 months ended December 31, 2007.

Basis of Presentation

Financial measures referred to in this discussion, such as funds from operations and funds from operations per share, are not prescribed by generally accepted accounting principles (GAAP). Funds from operations is a key measure that demonstrates the ability to generate cash to fund expenditures. Funds from operations is calculated by taking the cash provided by operations from the consolidated statement of cash flows and adding back changes in non-cash working capital. Funds from operations per share is calculated using the same share basis which is used in the determination of net income per share. These non-GAAP financial measures may not be comparable to similar measures presented by other companies. These financial measures are not intended to represent operating profits for the period nor should they be viewed as an alternative to cash provided by operating activities, net income or other measures of financial performance calculated in accordance with GAAP.

All barrels of oil equivalent (boe) conversions in this report are derived by converting natural gas to oil at the ratio of six thousand cubic feet (mcf) of natural gas to one barrel (bbl) of oil. Certain financial values are presented on a boe basis and such measurements may not be consistent with those used by other companies. Boe may be misleading, particularly if used in isolation. A boe conversion ratio of six mcf to one boe is based on an energy equivalency conversion method primarily applicable at the burner tip and does not necessarily represent a value equivalency at the wellhead.

Certain statements and information contained in this document, including but not limited to management's assessment of Rock's plans and future operations, production, reserves, revenue, commodity prices, operating and administrative expenditures, future income taxes, wells drilled, acquisitions and dispositions, funds from operations, capital expenditure programs and debt levels, contain forward-looking statements. All statements other than statements of historical fact may be forward-looking statements. These statements, by their nature, are subject to numerous risks and uncertainties, some of which are beyond Rock's control, including the effect of general economic conditions, industry conditions, regulatory and taxation regimes, volatility of commodity prices, currency fluctuations, the availability of services, imprecision of reserve estimates, geological, technical, drilling and processing problems, environmental risks, weather, the lack of availability of qualified personnel or management, stock market volatility, the ability to access sufficient capital from internal and external sources and competition from other industry participants for, among other things, capital, services, acquisitions of reserves, undeveloped lands and skilled personnel, any of which may cause actual results or events to differ materially from those anticipated in such forward-looking statements. Such forward-looking statements, although considered reasonable by management at the time of preparation, may prove to be incorrect and actual results may differ materially from those anticipated in the statements made and, therefore, should not unduly be relied on. These statements speak only as of the date of this document. Rock does not intend and does not assume any obligation to update these forward-looking statements, whether as a result of new information, future events or otherwise, except as required by applicable law.

All financial amounts are in thousands of Canadian dollars unless otherwise noted.

GUIDANCE AND OUTLOOK

The Company issued guidance on November 12, 2007 for projected 2007 and 2008 results. The table below provides the guidance for 2007 with actual results.

2007 Guidance

	2007 Guidance	Actual	Difference
2007 Production *(boe/d)*			
Annual	2,150-2,250	2,198	0%
Exit (December average)	2,600-2,800	2,617	(3)%
2006 Funds from Operations			
Annual	$15 million	$15.2 million	1%
Annual *(per share)*	$0.71	$0.72	1%
2006 Capital Budget			
Expenditures	$26 million	$25.6 million	(2)%
Gross wells drilled	16	16	0%
Total net debt at year end	$29 million	$29.1 million	0%
Pricing (Fourth Quarter)			
Oil – WTI	US$85.00/bbl	US$90.68/bbl	7%
Natural gas – AECO	$6.25/mcf	$6.15/mcf	(2)%
US/Cdn dollar exchange rate	1.05	1.02	(3)%

Production averages for the year and the exit rate were within the guidance range. Funds flow from operations was slightly above guidance as lower royalties offset higher G&A costs. Capital expenditures and debt levels were also at guidance levels.

Guidance for 2008 has been updated to reflect results from the winter drilling program and higher expected commodity prices. The table below updates the Company's previous guidance that was issued November 12, 2007.

	2008 Previous Guidance	2008 Revised Guidance	Change
2008 Production *(boe/d)*			
Annual	3,200-3,400	3,400-3,600	6%
Exit	3,700-3,900	3,900-4,100	5%

2008 Funds from Operations			
Annual	$22 million	$28 million	27%
Annual – *(per share)*	$0.86	$1.08	26%
2008 Capital Budget			
Expenditures	$24 million	$30 million	25%
Gross wells drilled	18-22	18-22	0%
Total net debt at year-end	$31 million	$31 million	0%
Pricing (Annual)			
Oil – WTI	US$75.00/bbl	US$85.00/bbl	13%
Natural gas – AECO	Cdn$6.75/mcf	Cdn$7.25/mcf	7%
US/Cdn dollar exchange rate	1.00	1.00	0%

Rock anticipates production from the Saxon winter program to begin by June 2008 versus the previous guidance of October 2008. The Company did not farm out this prospect and retained a 100 percent working interest versus a budgeted 70 percent working interest. As a result, average annual and exit production rates have increased by about 200 boe per day. Capital expenditures have also increased by $6 million to reflect the higher working interest at Saxon and additional infrastructure costs. In the previous guidance the majority of the Saxon infrastructure was to be owned by a third party however, Rock has decided to keep control of this infrastructure. The majority of the increased capital spending is projected to be incurred by June 2008.

Based on the strength of commodity prices to date in 2008, we have increased the reference price of WTI to US$85.00 per barrel and natural gas at AECO to Cdn$7.25 per mcf. Royalty rates are assumed to be approximately 22.5 percent, operating costs per boe have been held at the same rate as previous guidance of $12.20 per boe, G&A costs have decreased to $2.30 per boe based on increased production, and interest costs have been increased reflecting higher average debt levels in the first half of 2008. Funds from operations for 2008 are projected to increase $6 million to $28 million ($1.08 per basic share) based on increased production and commodity prices and other changes noted above.

Rock's bank is reviewing its borrowing base based on the 2007 year-end reserve report. We expect an increase in the loan facility to $38 million from $36 million and to put in place a $6 million development facility which will allow us to finance the increased capital expenditures at Saxon. Given the timing of the capital expenditures and on-stream production date for Saxon, the Company's debt-to-funds flow ratio (based on annualized quarterly funds from operations) is projected to rise to 1.9:1 in the first quarter of 2008 but then fall throughout the year to 1:1 by year-end. The Company will continue to monitor its funds from operations, capital program and debt levels and make adjustments to ensure the projected debt-to-cash flow ratio does not exceed 1.5:1 by year-end.

PRODUCTION and PRICES

Production by Product

	12 Months Ended 12/31/07	12 Months Ended 12/31/06	Change	3 Months Ended 12/31/07	3 Months Ended 12/31/06	Change
Natural gas *(mcf/d)*	4,261	6,421	(34)%	6,372	3,528	81%
Oil *(bbls/d)*	215	179	20%	206	206	0%
Heavy oil *(bbls/d)*	1,194	792	51%	1,323	1,168	13%
NGL *(bbls/d)*	79	57	39%	81	42	93%
Total (boe/d) *(6:1)*	2,198	2,098	5%	2,672	2,004	33%

Production by Area

	12 Months Ended 12/31/07	12 Months Ended 12/31/06	Change	3 Months Ended 12/31/07	3 Months Ended 12/31/06	Change
West Central Alberta *(boe/d)*	642	972	(34)%	1,041	652	60%
Plains *(boe/d)*	1,196	795	50%	1,325	1,171	13%
Other *(boe/d)*	360	331	9%	306	181	69%
Total (boe/d) *(6:1)*	2,198	2,098	5%	2,672	2,004	33%

Production increased 5 percent for the year ended December 31, 2007 over the prior year as the increase in heavy oil production more than offset the reduction in natural gas production. Heavy oil production increases were driven by drilling activity in 2007 and the latter half of 2006. Heavy oil production was negatively affected by natural gas migration issues at Edam in the second half of 2007 as natural gas appears to have permeated the oil zone. We are in the process of remediating the issue and hope to produce the natural gas from the oil zone by concurrently producing it with the oil starting in the second quarter of 2008.

Dispositions in July 2006 of approximately 820 boe per day reduced the natural gas production base for most of 2007 which was partially offset by the Greenbank acquisition that closed at the end of the third quarter in 2007. The Greenbank properties added approximately 500 boe per day of predominately natural gas production. The majority of the drilling in the West Central core area is directed at natural gas and the successful wells were not brought on-stream until the first quarter of 2008. Rock's current production is approximately 2,900 boe per day.

Production increased by 33 percent in the fourth quarter of 2007 from the same period last year as the Greenbank acquisition added production in the quarter while the property dispositions in July 2006 reduced production in the prior-year period. Post-2007 break-up drilling activities increased heavy oil production despite the loss of production from the natural gas migration issues at Edam. As a result of these activities the Company's natural gas weighting has increased from 29 percent in the fourth quarter of 2006 to 40 percent in the fourth quarter of 2007.

Product Prices

	12 Months Ended 12/31/07	12 Months Ended 12/31/06	Change	3 Months Ended 12/31/07	3 Months Ended 12/31/06	Quarterly Change

Realized Product Prices						
Natural gas *($/mcf)*	6.96	7.07	(2)%	6.64	7.45	(11)%
Oil *($/bbl)*	70.69	64.46	10%	81.66	57.77	41%
Heavy oil *($/bbl)*	41.18	38.35	7%	42.56	34.86	22%
NGL *($/bbl)*	60.00	61.35	(2)%	67.81	65.47	4%
Combined average ($/boe) *(6:1)*	44.93	43.27	4%	45.26	40.73	11%
	12 Months Ended 12/31/07	12 Months Ended 12/31/06	Change	3 Months Ended 12/31/07	3 Months Ended 12/31/06	Quarterly Change
Average Reference Prices						
Natural gas – Henry Hub Daily Spot *(US$/mmbtu)*	6.98	6.75	3%	7.01	6.69	5%
Natural gas – AECO C Daily Spot *($/mcf)*	6.45	6.54	(2)%	6.15	6.99	(12)%
Oil – WTI Cushing, Oklahoma *(US$/bbl)*	72.31	66.22	9%	90.68	60.21	51%
Oil – Edmonton Light *($/bbl)*	76.35	72.77	5%	86.42	64.49	34%
Heavy oil – Lloydminster blend *($/bbl)*	51.63	50.07	3%	55.49	43.84	27%
US/Cdn $ exchange rate	0.935	0.882	6%	1.019	0.878	16%

For the year and quarter ended December 31, 2007 the Company experienced higher oil prices and lower natural gas prices compared to the prior year periods. Rock's weighted average price per boe increased from the prior year which was driven by a higher overall oil weighting in the production mix. For the quarter the significant increase in oil pricing more than offset the reduction in natural gas pricing despite the increase in natural gas production in the overall production mix.

Heavy oil prices were stronger in both periods in 2007 compared to 2006 as WTI prices increased – more so in the fourth quarter of 2007. However, differentials widened in the fourth quarter of 2007 due to temporary pipeline issues, refinery turnarounds, higher condensate prices for blend and a stronger Canadian dollar. Oil prices have continued to remain strong in the first quarter of 2008 and the differential has narrowed and condensate prices have improved from fourth quarter 2007 levels. As a result Rock has been receiving more than $55 per barrel at the wellhead for heavy oil thus far in 2008.

Canadian natural gas prices for the year and fourth quarter of 2007 were below 2006 levels as the stronger Canadian dollar more than offset the modest increase in U.S. natural gas prices for these periods. Natural gas prices have improved in the first quarter of 2008 - currently over $8.00 per mcf - as colder weather has been experienced in North America and strong European and Asian pricing has reduced LNG shipments to North America. Reduced drilling activity in Canada should help support natural gas prices as supply is expected to decline. Natural gas prices traditionally decrease in the summer months as overall demand is reduced. Summer natural gas prices will be influenced by the amount of storage that needs to be replenished for the winter season, cooling demand and the amount of LNG that is imported into North America due to price differentials and demand in the European and Asian markets. The general lack of storage facilities in those markets could also impact the amount of LNG shipped to North America.

REVENUE

The vast majority of the Company's revenue is derived from oil and natural gas operations. Other income is primarily royalty interest revenue.

Oil and Natural Gas Revenue

	12 Months Ended 12/31/07	12 Months Ended 12/31/06	Change	3 Months Ended 12/31/07	3 Months Ended 12/31/06	Quarterly Change
Natural gas	$ 10,830	$ 16,560	(35)%	$ 3,890	$ 2,408	61%
Oil	5,538	4,195	31%	1,547	1,073	39%
Heavy oil	17,951	11,124	62%	5,180	3,790	38%
NGL	1,724	1,277	36%	507	264	100%
	36,042	33,156	9%	11,124	7,535	48%
Other revenue	$ 79	$ 198	(60)%	$12	$ 42	(71)%

Oil and natural gas revenue increased by 9 percent for the year ended December 31, 2007 over 2006 due to higher production levels, particularly heavy oil, which more than offset lower natural gas production. For the fourth quarter of 2007 oil and natural gas revenue increased by 48 percent from the same period in 2006 as higher production, particularly natural gas, and higher oil prices more than offset the decrease in natural gas prices.

ROYALTIES

	12 Months Ended 12/31/07	12 Months Ended 12/31/06	Change	3 Months Ended 12/31/07	3 Months Ended 12/31/06	Quarterly Change
Royalties	$7,035	$6,881	2%	$2,017	$1,452	39%
As a percentage of oil and natural gas revenue	19.5%	20.8%	(6)%	18.1%	19.3%	(6)%
Per boe *(6:1)*	$8.77	$8.98	(2)%	$8.21	$7.88	4%

Royalties increased for the year and quarter ended December 31, 2007 over the prior year periods due to higher production levels. The fourth quarter of 2007 included Alberta Royalty Tax Credits (ARTC) of $459. Although the ARTC program was cancelled effective January 1, 2007, the Alberta Government passed legislation late in 2007 allowing companies with off-calendar (non-December 31) tax year-ends to benefit from a full calendar year of ARTC. Without the ARTC benefit the royalty rates for 2007 would have been 22.2 percent for the quarter and 20.8 percent for the year. The Company is forecasting a royalty rate of approximately 22.5 percent for 2008.

OPERATING EXPENSES

	12 Months Ended 12/31/07	12 Months Ended 12/31/06	Change	3 Months Ended 12/31/07	3 Months Ended 12/31/06	Quarterly Change
Operating expense	$ 9,505	$ 8,947	6%	$ 2,889	$ 2,429	19%
Transportation costs	420	308	36%	130	83	57%
	9,925	9,255	7%	3,019	2,512	20%
Per boe *(6:1)*	$12.37	$12.08	2%	$12.28	$13.63	(10)%

Operating costs for the year and quarter ended December 31, 2007 have increased over 2006 primarily due to higher production. Operating expenses per boe were up slightly for the year ended 2007 compared to 2006 but down about 10 percent in the fourth quarter of 2007 versus the same period in 2006. Lower cost properties from the Greenbank acquisition benefitted fourth quarter 2007 results, while the fourth quarter of 2006 included prior period processing costs. Transportation costs have increased as a result of the acquired properties.

Heavy oil unit costs in 2007 decreased slightly year-over-year to $12.90 from $13.02 per boe and quarter-over-quarter to $13.61 from $14.33 per boe. Costs in the last half of 2007 trended up due to remediation efforts at Edam and 2006 costs were high due to the start-up costs as the result of significant heavy oil drilling that occurred in that year. Total Company operating expenses, including transportation expense, are forecast to be approximately $12.20 per boe in 2008.

GENERAL and ADMINSTRATIVE (G&A) EXPENSE

	12 Months Ended 12/31/07	12 Months Ended 12/31/06	Change	3 Months Ended 12/31/07	3 Months Ended 12/31/06	Quarterly Change
Gross	$ 4,791	$ 3,905	23%	$ 1,593	$ 1,085	47%
Per boe *(6:1)*	5.97	5.10	17%	6.48	5.89	10%
Capitalized and overhead recoveries	2,052	1,627	26%	638	395	62%
Per boe *(6:1)*	2.56	2.12	21%	2.60	2.14	21%
Net	2,739	2,278	20%	955	690	38%
Per boe *(6:1)*	3.41	2.97	15%	3.88	3.74	4%

G&A expense increased on an absolute and per boe basis in 2007 over 2006 due to a higher overall cost environment and in particular the fourth quarter of 2007 also includes $300 of one-time costs associated with management changes and transition costs related to the Greenbank acquisition. Rock capitalizes certain G&A expenses based on personnel involved in the exploration and development initiatives, including salaries and related overhead costs. Gross G&A expenses are expected to be flat on an absolute on an absolute basis in 2008 but decrease on a per boe basis as production is expected to increase.

INTEREST EXPENSE

	12 Months Ended 12/31/07	12 Months Ended 12/31/06	Change	3 Months Ended 12/31/07	3 Months Ended 12/31/06	Quarterly Change
Interest expense (recovery)	$ 1,157	$ 924	25%	$ 417	$ 141	195%
Per boe *(6:1)*	$1.44	$1.21	20%	$1.70	$0.76	121%

Interest expense has increased for the year and fourth quarter of 2007 over the 2006 periods due to higher average bank debt as capital expenditures, excluding acquisitions, exceeded funds from operations and were funded through the Company's bank facility. Interest expense is expected to increase again in 2008 due to higher average bank debt and increase approximately 20 percent on a per boe basis.

DEPLETION, DEPRECIATION, and ACCRETION (DD&A)

	12 Months Ended 12/31/07	12 Months Ended 12/31/06	Change	3 Months Ended 12/31/07	3 Months Ended 12/31/06	Quarterly Change
D&D expense	$ 13,989	$ 13,989	0%	$ 5,021	$ 2,707	85%
Per boe *(6:1)*	$17.44	$18.27	(5)%	$20.42	$14.69	39%
Accretion expense	$ 154	$ 129	20%	$ 48	$ 34	41%
Per boe *(6:1)*	$0.19	$0.17	14%	$0.20	$0.18	11%

Depletion and depreciation expense for the year ended December 31, 2007 equalled the prior year despite higher production and increased for the fourth quarter of 2007 from the 2006 period due to higher production and an increase in the per boe expense. The fourth quarter 2007 per boe depletion and depreciation expense increased as a result of negative reserve revisions recorded at Edam for the natural gas migration issue; reserves in the Greenbank acquisition which were at a higher cost than the existing base and increased capital activities in the West Central core area, which has relatively higher costs than the Plains core area.

The Company's asset retirement obligation (ARO) represents the present value of estimated future costs to be incurred to abandon and reclaim the Company's wells and facilities. The discount rate used is 8 percent.

Accretion represents the change in the time value of ARO. The underlying ARO may be increased over a period based on new obligations incurred from drilling wells, constructing facilities or acquiring operations. Similarly, this obligation can also be reduced as a result of abandonment work undertaken and reducing future obligations. During the year ended December 31, 2007 capital programs and acquisitions increased the underlying ARO by $1,592 (December 31, 2006 – $413) and actual expenditures on abandonments were nil (December 31, 2006 – $104).

INCOME TAX

The Company pays Saskatchewan resource capital taxes based on its production in the province. Rock does not have current income tax payable and does not expect to pay current income taxes in 2008 as the Company and its subsidiaries have estimated resource and other pools available at December 31, 2007 (after the allocation of deferred partnership income) of approximately $106.1 million as set out below:

CEE	$ 42.0 million
CDE	$ 28.5 million
COGPE	$ 4.7 million
UCC	$ 14.9 million
Loss carry-forwards	$ 14.5 million
Other	$ 1.5 million
Total	$ 106.1 million

FUNDS FROM OPERATIONS and NET INCOME/(LOSS)

	12 Months Ended 12/31/07	12 Months Ended 12/31/06	Change	3 Months Ended 12/31/07	3 Months Ended 12/31/06	Quarterly Change
Funds from operations	$15,189	$13,867	10%	$4,735	$2,644	79%
Per boe *(6:1)*	$18.93	$18.11	5%	$19.26	$14.35	34%
Per share:						
Basic	$0.72	$ 0.71	1%	$0.18	$ 0.13	38%
Diluted	$0.72	$ 0.71	1%	$0.18	$ 0.13	38%
Net income (loss)	$561	($884)	165%	$290	($119)	344%
Per boe *(6:1)*	$0.70	($1.15)	161%	$1.18	($0.65)	279%
Per share:						
Basic	$0.03	($0.05)	160%	$0.01	($0.01)	200%
Diluted	$0.03	($0.05)	160%	$0.01	($0.01)	200%
Weighted average shares outstanding:						
Basic	21,239	19,637	8%	25,847	19,637	32%
Diluted	21,239	19,655	8%	25,847	19,637	32%

The Company issued 6.1million shares at September 28, 2007 to acquire Greenbank and issued 0.1 million flow-through shares at November 1, 2007 to new management appointments. The Company did not issue any shares in 2006.

Funds from operations for the year ended December 31, 2007 increased by 10 percent over 2006 as the increase in production and realized prices more than offset the increase in royalties, operating, G&A and interest costs. On a per-boe basis, 2007 funds from operations increased by 5 percent from 2006 primarily for the same reasons except for the reduction in royalties. For the fourth quarter of 2007 funds from operations increased by 79 percent on an absolute basis and 34 percent on a per boe basis from the prior year's periods primarily as the increase in production and prices more than offset the increase in royalties, G&A and interest costs. On a per share basis, funds from operations was essentially flat in 2007 versus 2006 but increased 38 percent in the fourth quarter of 2007 over the same quarter in 2006. The Company generated net income for the year and quarter ended December 31, 2007 versus net losses in the prior year periods primarily as a result of booking future income tax recovery in 2007, compared to an expense in

2006, and as a result of the reduction in the future tax rate and the tax pools associated with the Greenbank acquisition. As a result net income per share also increased over the prior year periods.

CAPITAL EXPENDITURES

($000)	12 Months Ended 12/31/07	12 Months Ended 12/31/06	Change	3 Months Ended 12/31/07	3 Months Ended 12/31/06	Quarterly Change
Land	$ 3,723	$ 4,822	(23)%	$ 457	$ 120	280%
Seismic	1,359	1,081	26%	56	127	(56)%
Drilling and completions	16,689	25,130	(34)%	5,567	5,758	(3)%
Capitalized G&A	2,004	1,627	23%	589	395	49%
Natural gas gathering systems	694	247	181%	665	–	n/a
Total operations	$ 24,469	$ 32,907	(26)%	$ 7,334	$ 6,400	15%
Property acquisitions (dispositions) [(1)]	28,127	(30,874)	191%	Nil	Nil	n/a
Well site facilities inventory	94	(165)	157%	(19)	(206)	(91)%
Office equipment	1,012	136	644%	173	39	342%
Total (net of acquisitions and dispositions)	$ 53,702	$ 2,004	2,580%	$ 7,488	$ 6,233	20%

(1) Property acquisition for 2007 have been restated from the third quarter report to be presented as the amount allocated to property plant and equipment versus the consideration paid.

Capital expenditures for operations decreased for the year ended December 31, 2007 compared to 2006 as Rock drilled 16 (12.2 net) wells in 2007 versus 33 (28.3 net) wells in 2006. While the number of wells decreased the average cost per well increased as the Company participated in relatively more West Central core area operations than Plains core area operations in 2007. West Central core area targets tend to be deeper multi-zone natural gas targets which are more expensive than shallower heavy oil drilling that occurs in the Plains core area. Natural gas gathering expenditures also increased as tie-in operations were commenced in the Musreau and Kakwa areas and the resulting production came on-stream in the first quarter of 2008.

Land expenditures decreased as the Company focused more on drilling prospects that have been generated in the West Central core area. Seismic expenditures increased as additional seismic was acquired over the Elmworth area. Total net capital expenditures were increased to $54 million in 2007 from $2 million in 2006 as the Company completed the Greenbank acquisition in 2007 and divested properties in 2006.

During 2007, Rock drilled 11 (10.9 net) operated wells and five (1.3 net) non-operated wells, achieving a 91 percent success rate, compared to 27 (27.0 net) operated wells and six (1.3 net) non-operated wells and a 96 percent success rate in 2006. In the Plains core area Rock drilled 8 (8.0 net) heavy oil wells, one (0.9 net) natural gas well and one (1.0 net) dry hole. All of the wells were operated and all successful wells were on-production at year-end. The natural gas well was drilled at Edam and is part of the remediation efforts to remove natural gas from the oil zone. Plains core area production remained relatively flat in 2007 despite limited drilling and production problems at Edam. In the West Central Alberta core area Rock drilled five (2.2 net) natural gas wells and one (0.1 net) dry hole. Of the five natural gas wells drilled two (0.7 net) were at Kakwa, one (0.2 net) at Musreau, one (0.3 net) at Elmworth and one (1.0 net) at Saxon. The three wells at Kakwa and Musreau were tied-in in the first quarter of 2008 and the Elmworth and Saxon wells are expected to be tied-in the second quarter of 2008. Since year end one (1.0 net) additional natural gas well has been drilled at Saxon. The two Saxon wells and the Elmworth well are expected to add more than 800 boe per day of production once they are on stream.

LIQUIDITY AND CAPITAL RESOURCES

At the end of the third quarter of 2007, Rock completed the acquisition of Greenbank Energy by issuing 3.1 million shares and 3.0 million shares in a private placement to fund the cash portion of the transaction. Capital expenditures, excluding acquisitions, of $25.6 million in 2007 were primarily funded through cash from operations of $14.2 million and bank debt.

Rock's current approved capital budget for 2008 projects spending of $30 million. In 2008 funds from operations are expected to be approximately $28 million. The capital spending in excess of cash flow is intended to be funded through bank debt. Approximately half of the capital budget is expected to be spent in the first four months of the year as the Saxon infrastructure is put in place which should allow the associated production to be on-stream by June. The timing of expenditures will likely cause the Company to temporarily exceed its borrowing base and we expect the bank will provide a $6 million development facility to finance the capital requirements associated with the Saxon infrastructure. At year-end 2007 Rock had debt of $29.1 million against bank lines of $36 million. The bank is currently reviewing the borrowing base and we expect an increase in operating line to $38 million. The Company's debt-to-funds from operations ratio was 1.9:1 at year-end based on annual 2007 results; however this ratio includes all the debt from the Greenbank acquisition but only one quarter of the funds from operations. Based on annualized fourth quarter cash flow, the debt-to-funds from operations ratio was 1.5:1. With the current capital investemnt occurring in the West Central core area, Rock expects the debt-to-funds from operations ratio to increase to 1.9:1 in the first quarter of 2008 and then be reduced as production is brought on stream ending the year at 1.0:1.

The Company has a demand operating loan facility with a Canadian chartered bank. The facility is subject to the bank's valuation of the Company's oil and natural gas assets and the credit currently available is $36 million. The facility bears interest at the bank's prime rate or at the prevailing bankers' acceptance rate plus an applicable bank fee, which varies depending on the Company's debt-to-funds from operations ratio. The facility also bears a standby charge for undrawn amounts. The facility is secured by a first ranking floating charge on all real property of the Company, its subsidiary and partnership and a general security agreement. The next interim review for the facility is scheduled to be completed by April 30, 2008. As at March 11, 2008 approximately $30.1 million was drawn under the facility.

SELECTED ANNUAL DATA

The following table provides selected annual information for Rock:

	12 Months Ended 12/31/07	12 Months Ended 12/31/06	12 Months Ended 12/31/05
Production *(boe/d)*	2,198	2,098	1,122
Oil and natural gas revenues ($000)	$ 36,042	$ 33,156	$ 22,873
Average realized price *($/boe)*	$ 44.93	$ 43.27	$ 55.85
Royalties *($/boe)*	$ 8.77	$ 8.98	$ 12.28
Operating expense *($/boe)*	$ 12.37	$ 12.08	$ 11.59
Operating netback *($/boe)*	$ 23.79	$ 22.21	$ 31.98
Net G&A expense ($000)	$ 2,739	$ 2,278	$ 1,411
Stock-based compensation ($000)	$ 928	$ 1,188	$ 485
Funds from operations ($000)	$ 15,189	$ 13,867	$ 11,433
Per share – basic	$ 0.72	$ 0.71	$ 0.74

Per share – diluted	$ 0.72	$ 0.71	$ 0.74
Net income (loss)	$561	($884)	$ 1,510
Per share – basic	$0.03	($0.05)	$ 0.10
Per share – diluted	$0.03	($0.05)	$ 0.10
	As at 12/31/07	As at 12/31/06	As at 12/31/05
Total assets	$ 130,495	$ 85,380	$ 99,603
Total liabilities	$ 44,301	$ 24,901	$ 39,385

SELECTED QUARTERLY DATA

The following table provides selected quarterly information for Rock:

	3 Months Ended 12/31/07	3 Months Ended 09/30/07	3 Months Ended 06/30/07	3 Months Ended 03/31/07	3 Months Ended 12/31/06	3 Months Ended 09/30/06	3 Months Ended 06/30/06	3 Months Ended 03/31/06
Production *(boe/d)*	2,672	1,965	2,036	2,114	2,004	1,613	2,190	2,594
Oil and natural gas revenues ($000)	$ 11,126	$ 8,106	$ 8,279	$ 8,533	$ 7,535	$ 7,023	$ 8,774	$ 9,824
Average realized price *($/boe)*	$45.26	$44.85	$44.66	$44.84	$40.73	$47.30	$44.01	$42.08
Royalties *($/boe)*	$8.21	$9.18	$9.23	$8.66	$7.88	$5.27	$8.97	$12.26
Operating expense *($/boe)*	$12.28	$12.38	$12.10	$12.75	$13.63	$13.13	$10.55	$11.55
Operating netback *($/boe)*	$24.77	$23.29	$23.33	$23.43	$19.22	$28.90	$24.49	$18.27
Net G&A expense *($000)*	$ 955	$ 528	$ 530	$ 726	$ 690	$ 477	$ 462	$ 649
Stock-based compensation *($000)*	$ 213	$ 207	$ 241	$ 267	$ 295	$ 308	$ 305	$ 280
Funds from operations *($000)*	$ 4,735	$ 3,397	$ 3,536	$ 3,521	$ 2,644	$ 3,791	$ 4,028	$ 3,404
Per share – basic	$0.18	$ 0.17	$ 0.18	$ 0.18	$ 0.13	$ 0.19	$ 0.21	$ 0.17
Per share – diluted	$0.18	$ 0.17	$ 0.18	$ 0.18	$ 0.13	$ 0.19	$ 0.21	$ 0.17
Net income (loss) *($000)*	$290	$ 15	($117)	$ 373	($119)	$ 891	($583)	($1,074)
Per share – basic	$0.01	$ 0.00	($0.01)	$0.02	($0.01)	$ 0.05	($0.03)	($0.05)
Per share – diluted	$0.01	$ 0.00	($0.01)	$0.02	($0.01)	$ 0.05	($0.03)	($0.05)
Capital expenditures *($000)*	$ 7,488	$ 8,367	$ 2,552	$ 7,184	$ 6,223	$ 12,520	$ 4,397	$ 9,728
	As at 12/31/07	As at 09/30/07	As at 06/30/07	As at 03/31/07	As at 12/31/06	As at 09/30/06	As at 06/30/06	As at 03/31/06
Working capital *($000)*	($29,072)	($26,589)	($15,268)	($16,242)	($12,580)	($8,990)	($31,135)	($30,766)

Production was relatively flat over the first three quarters of 2007 as activities were primarily directed at West Central core area projects that are expected to be on-stream in the first half of 2008. Production increased in the fourth quarter of 2007 as a result of the Greenbank acquisition. The operating netback was also relatively stable over the first three quarters of 2007 resulting in a constant level of funds from operations. Improved pricing and lower royalties (due to the ARTC benefit) in the fourth quarter of 2007 increased the operating netback slightly and with higher production, funds from operations improved about 40 percent over the previous quarter.

G&A expenses were higher in the fourth quarter of 2007 due to costs associated with year-end reporting, management changes and Greenbank transition costs. Net capital expenditures were low in the second quarter of 2007 due to spring breakup conditions as the Company did not drill any wells. A significant portion of Rock's West Central core area activities are winter-access only and as a result these operations tend to be concentrated in the December to March timeframe. The Company usually undertakes Plains core area and Elmworth activities in the third quarter of the year. Negative working capital increased significantly in the last half of 2007 as Rock drilled 4 (4.0 net) heavy oil wells in the Plains core area and began operations in the West Central core area, particularly at Kakwa, Musreau, Elmworth and Saxon.

Reserves

Rock's reserves have been independently evaluated by GLJ Petroleum Consultants Ltd. (GLJ) at year-end 2007. This is the fourth year in which GLJ has evaluated the Company's reserves. The reserves as at December 31, 2007 and 2006 have been evaluated in accordance with *National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities (NI 51-101)*. The following tables provide a reconciliation of the Company's reserves between year-end 2006 and year-end 2007 on a gross basis (before deducting royalties and without including any royalty interest) (gross interest).

Rock's gross interest reserves at year-end 2007 are 5.3 million boe of proved reserves and 9.3 million boe of proved plus probable reserves. The growth in gross interest reserves resulted from oil and natural gas operations (net of revisions) which added 0.7 million boe of proved reserves and 0.9 million boe of proved plus probable reserves and the Greenbank acquisition which added 1.0 million of proved reserves and 1.9 million of proved plus probable reserves.

RESERVES RECONCILIATION

The following table is a reconciliation of Rock's gross interest reserves at December 31, 2007 using GLJ's forecast pricing and cost estimates as at December 31, 2007.

Reconciliation of Company Gross Interest Reserves by Principal Product Type (Forecast Prices and Costs)

	Light and Medium Oil		NGL		Heavy Oil		Natural Gas		Total Oil Equivalent	
Factors	Proved (mbbl)	Proved Plus Probable (mbbl)	Proved (mbbl)	Proved Plus Probable (mbbl)	Proved (mbbl)	Proved Plus Probable (mbbl)	Proved (mmcf)	Proved Plus Probable (mmcf)	Proved (mboe)	Proved Plus Probable (mboe)
December 31, 2006	413	588	119	183	2,705	4,299	7,507	13,591	4,488	7,334
Additions[1]	0	0	72	113	378	532	2,986	5,167	949	1,506
Technical revisions[2]	7	(3)	(3)	(9)	(359)	(617)	472	73	(278)	(617)
Acquisitions	45	69	45	98	0	0	5,289	10,383	971	1,898
Dispositions	0	0	0	0	0	0	0	0	0	0
Production	(81)	(81)	(26)	(26)	(450)	(450)	(1,536)	(1,536)	(812)	(812)
December 31, 2007	383	572	207	360	2,275	3,764	14,717	27,677	5,318	9,309

[1]Additions include discoveries, extensions, infill drilling and improved recovery.
[2]Technical revisions include technical revisions and economic factors.
Note: Figures may not add due to rounding; mbbl=1,000 bbl, mmcf=1,000 mcf, mboe = 1,000 boe.

RESERVES AND NET PRESENT VALUE (FORECAST PRICES AND COSTS)

The following tables summarize Rock's remaining gross interest reserves volumes along with the value of future net revenue utilizing GLJ's forecast pricing and cost estimates as at December 31, 2007.

Reserves

Reserves Category	Light and Medium Oil (mbbl)	NGL (mbbl)	Heavy Oil (mbbl)	Natural Gas (mmcf)	Total Oil Equivalent (mboe)
Proved					
Proved producing	323	99	1,919	7,230	3,545
Proved non-producing	60	91	124	5,440	1,183
Proved undeveloped	0	17	232	2,047	590
Total proved	383	207	2,275	14,717	5,318
Probable additional	189	152	1,489	12,960	3,991
Total proved plus probable	572	360	3,764	27,677	9,309

Note: Figures may not add due to rounding: mbbl=1,000 bbl, mmcf=1,000 mcf, mboe = 1,000 boe..

Net Present Value of Future Net Revenue

($000)	Before Income Taxes Discounted at (% per year)					After Income Taxes Discounted at (% per year)				
Reserves Category	0	5	10	15	20	0	5	10	15	20
Proved										
Proved producing	95,480	82,548	73,339	66,361	60,844	95,480	82,548	73,339	66,361	60,844
Proved non-producing	29,247	24,258	20,840	18,304	16,333	24,015	20,477	17,923	15,998	14,469
Proved undeveloped	6,439	4,508	3,106	2,058	1,254	4,623	2,948	1,754	875	211
Total proved	131,166	111,314	97,285	86,722	78,431	124,118	105,943	93,016	83,234	75,524
Probable additional	94,553	70,100	55,135	45,009	37,702	69,250	51,177	39,998	32,469	27,063
Total proved plus probable	225,719	181,414	152,420	131,731	116,133	193,639	157,121	133,014	115,703	102,587

Note: Figures may not add due to rounding.

PRICING ASSUMPTIONS

The following benchmark prices, inflation rates and exchange rates were used by GLJ for the forecast prices and costs evaluation.

Summary of Pricing and Cost Rate Assumptions at December 31, 2007 – Forecast Prices and Costs

	Oil				NGL				Natural Gas		
Year	WTI Cushing (US$/bbl)	Edmonton Reference Price ($/bbl)	Cromer Medium 29° API ($/bbl)	Hardisty Heavy 12° API ($/bbl)	Edmonton Propane ($/bbl)	Edmonton Butane ($/bbl)	Edmonton Pentane ($/bbl)	Ethane ($/bbl)	AECO-C ($/mcf)	US$/Cdn$ Exchange Rate	Cost Inflation Rate (%/year)
2008	92.00	91.10	79.26	54.02	58.30	72.88	92.92	22.73	6.75	1.00	2
2009	88.00	87.10	75.78	51.61	55.74	69.68	88.84	25.49	7.55	1.00	2
2010	84.00	83.10	72.30	49.19	53.18	66.48	84.76	25.66	7.60	1.00	2
2011	82.00	81.10	70.56	47.98	51.90	64.88	82.72	25.66	7.60	1.00	2
2012	82.00	81.10	70.56	47.98	51.90	64.88	82.72	25.66	7.60	1.00	2
2013	82.00	81.10	70.56	49.04	51.90	64.88	82.72	25.66	7.60	1.00	2
2014	82.00	81.10	70.56	50.09	51.90	64.88	82.72	26.35	7.80	1.00	2
2015	82.00	81.10	70.56	51.15	51.90	64.88	82.72	26.94	7.97	1.00	2
2016	82.02	81.12	70.57	52.21	51.91	64.89	82.74	27.52	8.14	1.00	2
2017	83.66	82.76	72.00	53.29	52.97	66.21	84.42	28.11	8.31	1.00	2
2018	85.33	84.42	73.44	54.36	54.03	68.20	86.11	28.67	8.48	1.00	2
2019+	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	1.00	2

FINDING, DEVELOPMENT AND ACQUISITION COSTS

The following table summarizes Rock's finding, development and acquisition costs for the years ended December 31, 2007, 2006 and 2005, including future development costs.

	12 months ended Dec. 31, 2007	12 months ended Dec. 31, 2006	12 months ended Dec. 31, 2005	3 Year Cumulative Total
Oil and Natural Gas Operations:				
Proved finding and development costs				
Capital expenditures[1] *($000)*	$24,163	$32,907	$22,912	$79,982
Change in future capital costs *($000)*	3,501	2,939	962	7,402
Total capital *($000)*	$27,664	$35,846	$23,874	$87,384
Reserve additions[2] *(mboe)*	949	2,181	1,188	4,318
Proved finding and development costs *($/boe)*	$29.15	$16.44	$20.10	$20.24
Proved plus probable finding and development costs				
Capital expenditures[1] *($000)*	$24,163	$32,907	$22,912	$79,982
Change in future capital costs *($000)*	3,930	7,986	$3,900	$15,816
Total capital *($000)*	$28,093	$40,893	$26,812	$95,798
Reserve additions[2] *(mboe)*	1,506	3,624	2,201	7,331
Proved plus probable finding and development costs *($/boe)*	$18.66	$11.28	$12.18	$13.07
Acquisitions/Dispositions:				
Proved finding and development costs – acquisitions (dispositions)				
Capital expenditures[1] *($000)*	$28,524	($30,878)	$60,853	$58,499
Change in future capital costs *($000)*	4,136	(2,400)	3,647	5,383
Total capital *($000)*	$32,660	($33,278)	$64,500	$63,882
Reserve additions *(mboe)*	971	(1,042)	2,397	2,326
Proved finding and development costs *($/boe)*	$33.64	($31.94)	$26.91	$27.46
Proved plus probable finding and development costs – acquisitions (dispositions)				
Capital expenditures[1] *($000)*	$28,524	($30,878)	$60,853	$58,499
Change in future capital costs *($000)*	11,417	(2,400)	3,733	12,750

Total capital *($000)*	$39,941	($33,278)	$64,586	$71,249
Reserve additions *(mboe)*	1,898	(1,406)	3,154	3,646
Proved plus probable finding and development costs *($/boe)*	$21.05	($23.67)	$20.48	$19.54
Total Activities:				
Proved finding and development costs				
Capital expenditures[1] *($000)*	$52,687	$2,029	$83,765	$138,481
Change in future capital costs *($000)*	7,637	539	4,609	12,785
Total capital *($000)*	$60,324	$2,568	$88,374	$151,266
Reserve additions[3] *(mboe)*	1,643	1,279	3,620	6,542
Total proved finding and development costs *($/boe)*	$36.72	$2.01	$24.41	$23.12
Proved plus probable finding and development costs				
Capital expenditures[1] *($000)*	$52,687	$2,029	$83,765	$138,481
Change in future capital costs *($000)*	15,347	5,586	7,633	28,566
Total capital *($000)*	$68,034	$7,615	$91,398	$167,047
Reserve additions[3] *(mboe)*	2,786	2,153	5,284	10,223
Total Proved plus probable finding and development costs *($/boe)*	$24.42	$3.54	$17.30	$16.34

[1] Capital expenditures include capitalized G&A which has been allocated between oil and natural gas operations and acquisitions, and exclude purchases of equipment still held in inventory and administrative capital expenditures.

[2] Reserve additions exclude revisions.

[3] Reserve additions include revisions.

[4] The aggregate of the exploration and development costs incurred in the most recent financial year and the change during that year in estimated future development costs generally will not reflect total finding and development costs related to reserve additions for that year.

Finding, development and acquisition ("FD&A") costs are broken down according to oil and natural gas operations, acquisitions and dispositions, and total activities. Oil and natural gas operations include all capital activities in which the Company participated, including operations on the acquired properties after their respective closing dates, but exclude reserve revisions. FD&A costs on the acquired properties are based on the reserve evaluation as at each respective year end less new reserves from operations post closing and were increased by the amount of production from the closing date to December 31 of the respective year to provide an estimate of the reserves purchased. FD&A costs on the disposed properties are based on the reserve evaluation as at December 31, 2005 and were decreased by the amount of production to the closing date. FD&A costs for total activities include operations, acquisitions, dispositions and reserve revisions.

Finding and development costs on operations increased in 2007 compared to 2006 and 2005 as Rock spent more capital in the higher cost West Central core area versus the relatively less expensive Plains core area in order to test the Company's exploration prospects, particularly Saxon and Kakwa. While the operations were successful these projects did not come on stream in 2007 and as a result reserve bookings, in management's view, are conservative given the lack of production history. In addition a significant amount of land, seismic and infrastructure costs (including future capital) are incurred for these projects. Future drilling locations should benefit from these expenditures. Rock completed the Greenbank acquisition at the end of the third quarter of 2007 and the reserve report contains a significant amount of future capital given the down spacing opportunities that exist on this land base. The FD&A calculations in the table above do not exclude any amounts for undeveloped land, valued at $5 million at the time of closing. Overall FD&A costs are high for 2007 and include significant technical revisions in our heavy oil properties particularly at Edam where the Company experienced the natural gas migration issue. Remediation efforts are currently underway to remove the natural gas from the oil zones and further restore production. If successful, management would expect to see a positive reserve revision in the future. On a three year basis the FD&A costs are in our view more reflective of the progress made in growing the Company and generate recycle ratios (FD&A divided by operating netback) of 1.9:1 for operations and 1.5:1 overall.

LAND HOLDINGS

The following table summarizes Rock's land holdings as at December 31, 2007 and 2006:

(acres)		Dec. 31, 2007	Dec. 31, 2006	Change
Developed	– Gross	87,882	63,085	39%
	– Net	32,406	23,566	38%
Undeveloped	– Gross	135,069	76,030	78%
	– Net	61,718	39,429	57%
Total	– Gross	222,951	139,115	60%
	– Net	94,123	62,995	49%

NET ASSET VALUE

The following table summarizes Rock's net asset value and net asset value per share as at December 31, 2007 and December 31, 2006:

($000 except number of shares and net asset value per share)	December 31, 2007	December 31, 2006	Change
Proved plus probable reserves[(1) (2)]	152,420	105,688	44%
Undeveloped land[(3)]	13,380	8,220	63%
Working capital including debt	(29,094)	(12,580)	132%
Net asset value (Basic)	136,706	101,328	35%
Basic shares *(000)*	25,878	19,637	32%
Net asset value per share (basic)	$5.28	$5.16	2%
Option proceeds	7,893	7,405	7%
Net asset value (Diluted)	144,599	108,733	33%
Diluted shares *(000)*	28,185	21,405	32%
Net asset value per share (diluted)	$5.13	$5.08	1%

(1) Proved plus probable reserves value is based on the net present value of future net revenue from gross reserves using GLJ Petroleum Consultants Ltd.'s January 2007 and 2006 forecast pricing and costs estimates and using a discount rate at 10 percent.

(2) Reserve values are based on the existing Alberta royalty regime.

(3) Undeveloped land value is based on the actual cost of land purchased at land sales; land acquired from EIM/Optimum/Qwest in the second quarter of 2005 has been valued at $100 per acre and land acquired through the Greenbank acquisition in the third quarter of 2007 has been valued at $200 per acre.

Reserve values in the above table are based on the existing Alberta royalty regime. GLJ Petroleum Consultants Ltd. prepared high and low sensitivity cases under the proposed Alberta royalty regime based on assumptions that all independent consulting firms agreed to use in their evaluations. The low royalty sensitivity case assumes that a heavy oil par price is used in the royalty calculations, solution natural gas royalties are calculated using the same rate and price basis as non-associated natural gas, and the deep natural gas royalty adjustment is applied to all existing and future wells. The high royalty sensitivity case assumes that a light oil par price is used in the royalty calculations for heavy oil, solution natural gas royalties are calculated using the same rate and price basis as non-associated natural gas but restricted to no less than the current royalty rate of 30 percent on solution natural gas, and the deep natural gas royalty adjustment is applied only to wells drilled after 2008.

The following table summarizes Rock's proved and probable reserve values, net asset value and net asset value per share as at December 31, 2007 under the different royalty assumptions:

($000 except number of shares and net asset value per share)	December 31, 2007 Existing Royalty	December 31, 2007 Low Royalty	December 31, 2007 High Royalty
Proved plus probable reserves[(1)]	152,420	152,420	144,747
Net asset value (Basic)	136,706	136,706	129,033
Basic shares *(000)*	25,878	25,878	25,878
Net asset value per share (basic)	$5.28	$5.28	$4.99
Net asset value (Diluted)	144,599	144,599	136,926
Diluted shares *(000)*	28,185	28,185	28,185

Net asset value per share (diluted)	$5.13	$5.13	$4.86

[1] Proved plus probable reserves value is based on the net present value of future net revenue from gross reserves using GLJ Petroleum Consultants Ltd.'s January 2007 forecast pricing and costs estimates and using a discount rate at 10 percent.

CONTRACTUAL OBLIGATIONS

In the course of its business, the Company enters into various contractual obligations including the following:

- royalty agreements;
- processing agreements;
- right-of-way agreements; and
- lease obligations for office premises.

Obligations with a fixed term are as follows:

	2008	2009	2010	2011	2012
Office premise leases	$ 895	$ 828	$ 828	$ 828	$ 552
Processing agreements	450	360	288	238	159
Demand bank loan[1]	$27,405				

[1] The demand bank loan is currently under its annual review and is expected to remain in place.

OUTSTANDING SHARE DATA

At December 31, 2007 and to date, Rock had 25,877,642 common shares outstanding. At December 31, 2007 the Company had 2,307,822 stock options outstanding with an average exercise price of $3.42 per share. As of the date hereof Rock has 2,145,363 options outstanding.

OFF-BALANCE-SHEET ARRANGEMENTS

Rock does not have any special-purpose entities nor is it party to any arrangement that would be excluded from the balance sheet.

RELATED-PARTY TRANSACTIONS

The Company has not entered into any related-party transactions during the reporting period.

DISCLOSURE CONTROLS AND PROCEDURES

The Company has a corporate disclosure policy that is distributed to and made available to staff through the corporate computer network. The policy is reviewed by the Chief Executive Officer, Chief Financial Officer and the Board of Directors annually. Procedures were developed and put in place in support of the disclosure policy. The Chief Executive Officer and the Chief Financial Officer have evaluated the effectiveness of the disclosure controls and procedures as at December 31, 2007 and, based on that evaluation; believe them to be effective given the size and nature of the Company's operations. All control systems by their nature have inherent limitations and, therefore, Rock's disclosure controls and procedures are believed to provide reasonable, but not absolute, assurance that:

- the communications by the Company with the public are timely, factual and accurate and broadly disseminated in accordance with all applicable legal and regulatory requirements;
- non-publicly disclosed information remains confidential; and
- trading of the Company's securities by directors, officers and employees remains in compliance with applicable securities laws.

INTERNAL CONTROLS OVER FINANCIAL REPORTING

The Chief Executive Officer and the Chief Financial Officer have supervised the design of internal controls over financial reporting and these controls were in place as at December 31, 2007. The Company acquired Greenbank at the end of the third quarter of 2007 and assimilated the accounts into Rock's existing accounts and as a result there was no material change to the design of internal controls over financial reporting. In addition the Company did not make any other material change to internal controls in 2007. The Chief Executive Officer and the Chief Financial Officer believe the internal controls, including compensating controls to overcome the lack of certain segregation of duties, are designed appropriately given the nature and size of the Company's operations, and that a material deficiency in design does not exist. Because of their inherent limitations, internal controls over financial reporting may not prevent or detect misstatements, errors or fraud. Control systems, no matter how well conceived or operated, can provide only reasonable, not absolute assurance that the objectives of the control systems are met.

CHANGE IN ACCOUNTING POLICIES

As of January 1, 2007 the Company adopted new policies to implement the pronouncements from the Canadian Institute of Chartered Accountants in respect of financial instruments - presentation and disclosures, hedging and other comprehensive income. The new standards require certain financial instruments to be recognized on the balance sheet at their fair value. The application of these policies did not result in changes to amounts reported in the consolidated financial statements for the period ended December 31, 2007.

NEW ACCOUNTING PRONOUNCEMENTS

Capital Disclosures

The Canadian Institute of Chartered Accountants (CICA) issued CICA Handbook section 1535, Capital Disclosures. The section is effective for fiscal years beginning on or after October 1, 2007. It requires disclosure on objectives, policies and processes for managing capital.

Rock will adopt this section effective January 1, 2008.

Financial Instruments – Disclosures and Presentation

The Canadian Institute of Chartered Accountants (CICA) issued CICA Handbook section 3862, Financial Instruments - Disclosures and section 3863, Financial Instruments - Presentation which replace section 3861, Financial Instruments – Disclosures and Presentation. These sections are effective for fiscal years beginning on or after October 1, 2007. Section 3863 does not change the presentation requirements of the previous section 3861 however, section 3862 places new increased emphasis on the nature and extent of risks arising from financial instruments and how they are managed. Rock will adopt this section effective January 1, 2008.

International Financial Reporting Standards

The Canadian Institute of Chartered Accountants proposed to implement International Financial Reporting Standards ("IFRS") as part of Canadian GAAP. The adoption of IFRS in Canada will result in significant changes to current Canadian GAAP and to financial reporting practices followed by Rock. IFRS accounting standards are scheduled to be implemented for years beginning after December 31, 2010. Rock will be required to adopt the standard for the year beginning January 1, 2011. Currently, the application of IFRS in Canada and particularly to the oil and natural gas industry requires further clarification and as a result the effect of IFRS adoption on the Company's accounting policies and reporting standards and practices is not presently determinable.

CRITICAL ACCOUNTING ESTIMATES

A summary of the Company's significant accounting policies is contained in note 2 to the audited consolidated financial statements. These accounting policies are subject to estimates and key judgements about future events, many of which are beyond Rock's control. The following is a discussion of the accounting estimates that are critical to the financial statements.

Oil and Natural Gas Accounting – Reserves Recognition – Rock retained independent petroleum engineering consultants GLJ Petroleum Consultants Ltd. (GLJ) to evaluate its oil and natural gas reserves, prepare an evaluation report, and report to the Company's Reserves Committee. The process of estimating oil and natural gas reserves is subjective and involves a significant number of decisions and assumptions in evaluating available geological, geophysical, engineering and economic data. These estimates will change over time as additional data from ongoing development and production activities becomes available and as economic conditions affecting oil and natural gas prices and costs change. Reserves can be classified as proved, probable or possible with decreasing levels of certainty to the likelihood that the reserves will be ultimately produced.

Oil and Natural Gas Accounting – Full Cost Accounting – Under the full cost method of accounting for exploration and development activities, all costs associated with these activities are capitalized. The aggregate net capitalized costs and estimated future abandonment costs, less estimated salvage values, are amortized using the unit-of-production method based on estimated proved oil and natural gas reserves, resulting in a depletion expense. The depletion expense is most affected by the estimate of proved reserves and the cost of unproved properties. Unproved costs are reviewed quarterly to determine if proved reserves have been established, at which point the associated costs are included in the depletion calculation. Changes to any of these estimates may affect Rock's earnings.

Under the full cost method of accounting, the Company's investment in oil and natural gas assets is evaluated at least annually to consider whether the investment is recoverable and the carrying amount does not exceed the value of the properties, a process known as the "ceiling test". The carrying value of oil and natural gas properties and production equipment is compared to the sum of undiscounted cash flows expected to result from Rock's proved reserves. If the carrying value is not fully recoverable, the amount of impairment is measured by comparing the carrying value of property and equipment to the estimated net present value of future cash flows from proved plus probable reserves using a risk-free interest rate. Any excess carrying value above the net present value of the future cash flows is recorded as a permanent impairment. Reserve, revenue, royalty and operating cost estimates and the timing of future cash flows are all critical components of the ceiling test. Revisions of these estimates could result in a write-down of the carrying amount of oil and natural gas properties.

Asset Retirement Obligations – The Company recognizes the estimated fair value of an asset retirement obligation (ARO) in the period in which it is incurred as a liability, and records a corresponding increase in the carrying value of the related asset. The future asset retirement obligation is an estimate based on the Company's ownership interest in wells and facilities and reflects estimated costs to complete the abandonment and reclamation as well as the estimated timing of the costs to be incurred in future periods. Estimates of the costs associated with abandonment and reclamation activities require judgement concerning the method, timing and extent of future retirement activities. The capitalized amount is depleted on a unit-of-production method over the life of the proved reserves. The liability amount is increased each reporting period due to the passage of time and this accretion amount is charged to earnings in the period. Actual costs incurred on settlement of the ARO are charged against the ARO. Judgements affecting current and annual expense are subject to future revisions based on changes in technology, abandonment timing, costs, discount rates and the regulatory environment.

Stock-based Compensation – Stock options issued to employees and directors under the Company's stock option plan are accounted for using the fair value method of accounting for stock-based compensation. The fair value of the option is recognized as stock-based compensation expense and contributed surplus over the vesting period of the option. Stock-based compensation expense is determined on the date of an option grant using the Black-Scholes option pricing model. The Black-Scholes pricing model requires the estimation of several variables including estimated volatility of Rock's stock price over the life of the option, estimated option forfeitures, estimated life of the option, estimated risk-free rate and estimated dividend rate. A change to these estimates would alter the valuation of the option and would result in a different related stock-based compensation expense.

Goodwill – The Company recognized goodwill in conjunction with the Elm/Optimum/Qwest acquisitions that occurred in the second quarter of 2005. In assessing if goodwill has been impaired the Company assesses the fair value of its assets and liabilities. This assessment takes into consideration such factors as: the estimated fair value of the Company's reserves and unproven properties; the current trading value of the common shares; and recent market transactions for similar types of assets. If the Company's common share trading value was to deteriorate from current levels an impairment to goodwill might exist.

BUSINESS RISKS

Rock is exposed to a number of business risks, some of which are beyond its control, as are all companies in the oil and natural gas exploration and production industry. These risks can be categorized as operational, financial and regulatory.

Operational risks include generating, finding and developing, and acquiring oil and natural gas reserves on an economical basis (including acquiring land rights or gaining access to land rights); reservoir production performance; marketing; production; hiring and retaining employees; and accessing contract services on a cost-effective basis. Rock attempts to mitigate these risks by employing highly qualified staff and operating in areas where employees have expertise. In addition the Company outsources certain activities to be able to lever industry expertise, without having the burden of hiring full-time staff given the current scope of operations. Typically the Company has outsourced the marketing and certain engineering and land functions. Rock is attempting to acquire oil and natural gas operations; however Rock will be competing against many other companies for such operations, many of which will have greater access to resources. As a small company, gaining access to contract services may be difficult given the competitive nature of the industry, but Rock will attempt to mitigate this risk by utilizing existing relationships.

Financial risks include commodity prices, the Canadian/US dollar exchange rate and interest rates, all of which are largely beyond the Company's control. Currently Rock has not used any financial instruments to mitigate these risks. The Company would consider using these financial instruments depending on the operating environment. The Company also will require access to capital. Currently Rock has a debt facility in place and intends to use its debt capacity in the future in conjunction with capital expenditures including acquisitions. It intends to use prudent levels of debt to fund capital programs based on the expected operating environment. It also intends to access equity markets to fund opportunities; however, the ability to access these markets will be determined by many factors, many of which will be beyond the control of the Company.

Rock is subject to various regulatory risks, principally environmental in nature. The Company has put in place a corporate safety program and a site-specific emergency response program to help manage these risks. The Company hires third-party consultants to help develop and manage these programs and help Rock comply with current environmental legislation. Increased public and political concern regarding climate change issues will likely result in increased regulation regarding emissions standards. Given that the Company produces hydrocarbons, such regulation could cause Rock to alter the way it operates and also result in additional costs and taxes associated with climate change regulation which could have a material effect on the Company.

ADDITIONAL INFORMATION

Further information regarding the Company, including the Company's Annual Information Form, can be accessed under the Company's public filings found on SEDAR at www.sedar.com. Information can also be obtained by contacting the Company at Rock Energy Inc., Suite 800, 607 - 8th Avenue S.W., Calgary, Alberta, T2P 0A7.

Management's Report

To the Shareholders of Rock Energy Inc.:

The financial statements of Rock Energy Inc. were prepared by management in accordance with appropriately selected generally accepted accounting principles in Canada. Management has used estimates and careful judgement, particularly in those circumstances where transactions affecting current periods are dependent on information not known until a future period. The financial and operational information contained in this annual report is consistent with that reported in the financial statements.

Management is responsible for the integrity of the financial and operational information contained in this report. The Company has designed and maintains internal controls to provide reasonable assurance that assets are properly safeguarded and that the financial records are well maintained and provide relevant, timely and reliable information to management. The financial statements have been prepared within reasonable limits of materiality and within the framework of the significant accounting policies summarized in the notes to the financial statements.

External auditors appointed by the shareholders have conducted an independent examination of the corporate and accounting records in order to express their opinion on the financial statements. The Audit Committee has met with the external auditors and management in order to determine if management has fulfilled its responsibilities in the preparation of the financial statements. The Board of Directors has approved the financial statements on the recommendation of the Audit Committee.

Allen J. Bey
President and Chief Executive Officer
March 12, 2008

Peter D. Scott

Vice President, Finance and Chief Financial Officer

March 12, 2008

Auditors' Report

We have audited the consolidated balance sheets of Rock Energy Inc. as at December 31, 2007 and 2006 and the consolidated statements of income (loss), comprehensive income (loss) and retained earnings and cash flows for the years then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2007 and 2006 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

KPMG LLP

Chartered Accountants

Calgary, Canada
March 12, 2007

Consolidated Balance Sheets
(000s of dollars)

As at	December 31, 2007	December 31, 2006
Assets		
Current assets		
Accounts receivable	$ 8,473	$ 4,753
Prepaid expenses	1,383	532
	9,856	5,285
Property, plant and equipment *(note 5)*	151,762	97,229
Accumulated depletion and depreciation	(36,871)	(22,882)
	114,891	74,347
Goodwill	5,748	5,748
	$ 130,495	$ 85,380
Liabilities and Shareholders' Equity		
Current liabilities		
Accounts payable and accrued liabilities	$ 11,523	$ 6,900
Bank debt *(note 6)*	27,405	10,965
	38,928	17,865
Future tax liability *(note 10)*	1,533	4,942
Asset retirement obligation *(note 7)*	3,840	2,094
Shareholders' equity		
Share capital *(note 8)*	81,600	57,326
Contributed surplus *(note 9)*	2,521	1,641
Retained earnings	2,073	1,512
	86,194	60,479
Commitments *(note 12)*		
	$ 130,495	$ 85,380

See accompanying notes to consolidated financial statements.

Approved by the Board:

James K. Wilson
Director

Allen J. Bey
Director

Consolidated Statements of Income (Loss), Comprehensive Income (Loss) and Retained Earnings

(000s of dollars, except per share amounts)

Years ended	December 31, 2007	December 31, 2006
Revenues:		
Oil and natural gas revenue	$ 36,042	$ 33,156
Royalties	(7,035)	(6,881)
Other income	79	198
	29,086	26,473
Expenses:		
General and administrative	2,739	2,278
Operating	9,925	9,255
Interest	1,157	924
Stock-based compensation *(note 9)*	931	1,188
Depletion, depreciation, and accretion	14,143	14,118
	28,895	27,763
Income (loss) before taxes	191	(1,290)
Taxes		
Provincial capital taxes *(note 10)*	76	45
Future income taxes (reduction) *(note 10)*	(446)	(451)
Net income (loss) and comprehensive income (loss) for the year	561	(884)
Retained earnings, beginning of year	1,512	2,396
Retained earnings, end of year	$ 2,073	$ 1,512
Diluted and basic net income (loss) per share *(note 8)*	$ 0.03	$ (0.05)

See accompanying notes to consolidated financial statements.

Consolidated Statements of Cash Flows

(000s of dollars)

Years ended	December 31, 2007	December 31, 2006
Cash provided by (used in):		
Operating:		
Net income (loss) for the year	$ 561	$ (884)
Add: Non-cash items:		
Depletion, depreciation, and accretion	14,143	14,118
Actual abandonment costs	-	(104)
Stock-based compensation	931	1,188
Future income taxes (reduction)	(446)	(451)
	15,189	13,867
Changes in non-cash working capital	(1,035)	2,571
	14,154	16,438
Financing:		
Issuance of common shares	12,456	-
Bank debt	10,903	(12,011)
Repurchase of stock options	(51)	-
	23,308	(12,011)
Investing:		
Property, plant and equipment	(25,575)	(32,879)
Acquisition of property, plant and equipment *(note 4)*	(12,644)	-
Disposition of property, plant and equipment	-	30,874
Changes in non-cash working capital	757	(2,567)
	(37,462)	(4,572)
Decrease in cash and cash equivalents	-	(145)
Cash and cash equivalents, beginning of year	-	145
Cash and cash equivalents, end of year	$ -	$ -
Interest and taxes paid and received:		
Interest paid	$ 1,190	$ 960
Interest received	34	32
Taxes paid	142	25

See accompanying notes to consolidated financial statements.

Years ended December 31, 2007 and 2006

1. Nature of Operations

Rock Energy Inc. (the "Company" or "Rock") is actively engaged in the exploration, production and development of oil and natural gas in Western Canada.

2. Significant Accounting Policies

The consolidated financial statements of Rock are stated in Canadian dollars and have been prepared in accordance with Canadian generally accepted accounting principles (GAAP).

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amount of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the period. Actual results could differ from those estimates.

(A) CONSOLIDATION

These consolidated financial statements include the accounts of Rock Energy Inc., Rock Energy Ltd. and Rock Energy Production Partnership. All inter-company transactions and balances have been eliminated upon consolidation.

(B) CASH AND CASH EQUIVALENTS

Cash and cash equivalents are comprised of cash and short-term investments with a maturity date of 12 months or less.

(C) JOINT OPERATIONS

A substantial portion of the Company's oil and natural gas exploration and development activities is conducted jointly with others and, accordingly, these consolidated financial statements reflect only the Company's proportionate interest in such activities.

(D) PROPERTY, PLANT AND EQUIPMENT

Capitalized costs: The Company follows the full cost method of accounting for its oil and natural gas operations, whereby all costs related to the acquisition, exploration and development of petroleum and natural gas reserves are capitalized. Such costs include lease acquisition costs, geological and geophysical costs, carrying charges on non-producing properties, costs of drilling both productive and non-productive wells, the cost of petroleum and natural gas production equipment and overhead charges directly related to exploration and development activities. Proceeds from the sale of oil and natural gas properties are applied against capital costs, with no gain or loss recognized, unless such a sale would change the rate of depletion and depreciation by 20 percent or more, in which case a gain or loss would be recorded.

Depletion, depreciation and amortization: The capitalized costs are depleted and depreciated using the unit-of-production method based on proved petroleum and natural gas reserves, as determined by independent consulting engineers. Oil and natural gas liquids reserves and production are converted into equivalent units of natural gas based on relative energy content. Office furniture and equipment are recorded at cost and depreciated on a declining balance basis using a rate of 20 percent.

Ceiling test: Rock calculates its ceiling test by comparing the carrying value of oil and natural gas properties and production equipment to the sum of undiscounted cash flows from proved reserves. If the carrying value is not fully recoverable, the amount of impairment is measured by comparing the carrying value of property and equipment to the estimated net present value of future cash flows from proved plus probable reserves, using a risk-free interest rate and expected future prices, and unproved properties. Any excess carrying value above the net present value of the future cash flows is recorded as a permanent impairment.

Asset retirement obligations: The Company records the fair value of an asset retirement obligation (ARO) as a liability in the period in which it incurs a legal obligation to restore an oil and natural gas property, typically when a well is drilled or other equipment is put in place. The associated asset retirement costs are capitalized as part of the carrying amount of the related asset and depleted on a unit-of-production method over the life of the proved reserves. Subsequent to initial measurement of the obligations, the obligations are adjusted at the end of each reporting period to reflect the passage of time and changes in estimated future cash flows underlying the obligation. Actual costs incurred on settlement of the ARO are charged against the ARO.

(E) GOODWILL

Goodwill is the residual amount that results when the purchase price of an acquired business exceeds the fair value for accounting purposes of the net identifiable assets and liabilities of the acquired business. Goodwill is stated at cost less any impairment and is not amortized. The goodwill balance is subject to an impairment test whereby the book value of the Company's equity is compared to its fair value. If the fair value of the Company's equity is less than book value, impairment is measured by allocating the fair value of the identifiable assets and liabilities at their fair values. The difference between the Company's fair value and book value of identifiable assets and liabilities is the fair value of goodwill. Any excess of the book value of goodwill over the implied fair value of goodwill is the impairment amount. Impairment is charged to income in the period in which it occurs. The impairment test is carried out annually, or more frequently if circumstances occur that are more likely than not to reduce the fair value of the acquired business below its carrying amount.

(F) INCOME TAXES

Income taxes are calculated using the asset and liability method of tax accounting. Temporary differences arising from the difference between the tax basis of an asset or liability and its carrying value on the balance sheet are used to calculate future income tax assets and liabilities. Future income tax assets and liabilities are calculated using tax rates anticipated to apply in the periods when the temporary differences are expected to reverse.

(G) FLOW-THROUGH SHARES

The resource expenditure deductions for income tax purposes related to exploratory and development activities funded by flow-through share arrangements are renounced to investors in accordance with income tax legislation. Future tax liabilities and share capital are adjusted by the estimated cost of the renounced tax deduction when the expenses are renounced.

(H) STOCK-BASED COMPENSATION

The Company grants options to purchase common shares to employees and directors under its stock option plan. Awards are accounted for using the fair value of accounting for stock-based compensation. Under the fair value method, an estimate of the value of the option is determined at the time of grant using the Black-Scholes option pricing model. The fair value of the option is recognized as an expense and contributed surplus over the vested life of the option.

(I) REVENUE RECOGNITION

Revenue from the sale of oil and natural gas is recognized based on volumes delivered to customers at contractual delivery points and rates.

(J) MEASUREMENT UNCERTAINTY

The amounts recorded for depletion and depreciation of property, plant and equipment, the provision for asset retirement obligations, the amounts used for ceiling test calculations and fair value of identifiable assets for goodwill impairment are based on estimates of reserves and future costs. The Company's reserve estimates are reviewed annually by an independent engineering firm. The amounts disclosed relating to fair values of stock options issued are based on estimates of future volatility of the Company's share price, expected lives of options, and other relevant assumptions. By their nature, these estimates are subject to measurement uncertainty and the impact on the consolidated financial statements of changes in such estimates in future periods could be material.

(K) PER SHARE AMOUNTS

Basic per share amounts are calculated using the weighted average number of shares outstanding during the year. Diluted per share amounts are calculated based on the treasury stock method whereby the weighted average number of shares is adjusted for the dilutive effect of options.

3. Accounting Policies Changes and Pending Changes

(A) FINANCIAL INSTRUMENTS

As of January 1, 2007 the Company adopted new policies to implement the pronouncements from the Canadian Institute of Chartered Accountants (CICA) in respect of financial instruments – presentation and disclosures, hedging and other comprehensive income. The application of these policies did not result in changes to amounts reported in the consolidated financial statements for the year ended December 31, 2007.

On initial recognition all financial instruments, including derivatives, are recorded at fair value and subsequent measurement is based on the financial instruments classification: held for trading, held to maturity, loans and receivables, available for sale and other liabilities.

The Company has designated its cash and cash equivalents as held for trading which are measured at fair value. Accounts receivable are classified as loans and receivables which are measured at amortized cost. Accounts payable and accrued liabilities and bank debt are classified as other liabilities which are measured at amortized cost, using the effective interest method.

The Company is exposed to fluctuations in commodity prices, foreign exchange rates and interest rates. Derivative instruments may be used by the Company to reduce its exposure to fluctuations in commodity prices, foreign exchange rates, and interest rates. If derivatives instruments were used they would be classified as held for trading and recorded on the balance sheet at fair value, with changes in the fair value recognized in income, unless specific hedge criteria were met. The fair values of derivative instruments would be based on an estimate of the amounts that would have been received or paid to settle these instruments prior to maturity. Proceeds and costs realized from holding derivative instruments would be recognized in income at the time each transaction under a contract was settled.

The Company has elected to account for its physical delivery sales contracts, which were entered into and continue to be held for the purpose of receipt or delivery of non-financial items in accordance with its expected purchase, sale or usage requirements as executory contracts on an accrual basis rather than as non-financial derivatives instruments.

The Company measures and recognizes embedded derivatives separately from the host contracts when the economic characteristics and risks of the embedded derivative are not closely related to those of the host contract, when it meets the definition of a derivative and when the entire contract is not measured at fair value. Embedded derivatives are recorded at fair value.

The Company applies trade-date accounting for the recognition of a purchase or sale of cash equivalents and derivative instruments. The Company expenses all transaction costs incurred in relation to the acquisition of a financial asset or liability.

The CICA has issued two new financial instruments standards: Section 3862, Financial Instruments - Disclosures, and Section 3863, Financial Instruments - Presentation. The new disclosure standards effective January 1, 2008 may increase the Company's disclosures on risks related to financial instruments and how those risks are managed.

(B) COMPREHENSIVE INCOME

A new standard adopted requires statements of comprehensive income and accumulated other comprehensive income to temporarily provide for gains, losses and other amounts arising from changes in fair value until they are realized and recorded in income. The Company had no items that would affect comprehensive income or accumulated other comprehensive income for the year ended December 31, 2007.

(C) CAPITAL DISCLOSURES

As of January 1, 2008, the Company will be required to adopt Section 1535, Capital Disclosures, which require disclosure of the Company's objectives, policies and processes for managing capital.

(D) GOODWILL

As of January 1, 2009, the Company will be required to adopt Section 3064, Goodwill and Intangible Assets, which defines the criteria for the recognition of intangible assets.

(E) INTERNATIONAL REPORTING STANDARDS

The CICA has confirmed the effective date of January 1, 2001 for the convergence of Canadian GAAP to International Financial Reporting Standards. The Canadian Securities Administrators are currently examining changes to securities laws as a consequence of this initiative.

4. Acquisition of Greenbank Energy Ltd.

On July 31, 2007 the Company agreed to acquire a private company by way of a plan of arrangement for cash and shares of the Company. The transaction closed on September 28, 2007 and has been accounted for using the purchase method and the results of operations for the transaction are included in the financial statements beginning in the fourth quarter of 2007.

The purchase price equation is as follows:

($000)	
Property, plant and equipment	$ 28,127
Bank debt	(5,537)
Working capital deficiency	(330)
Asset retirement obligation	(761)
Future income tax asset	2,963
	$ 24,462
Consideration provided:	
Cash from private placement	$ 12,144
Common shares (3,143,167)	11,818
Transaction costs	500
	$ 24,462

The preliminary purchase price allocations were based on certain estimates such as the fair values of the assets and liabilities as of the closing date. The items to be finalized in the purchase price allocation relate to working capital deficiency and transaction costs.

5. Property, Plant and Equipment

($000)	December 31, 2007	December 31, 2006
Petroleum and natural gas properties	$ 150,408	$ 96,887
Other assets	1,354	342
	151,762	97,229
Accumulated depletion and depreciation	(36,871)	(22,882)
	$ 114,891	$ 74,347

At December 31, 2007, the depletable base for the petroleum and natural gas properties included $14,404 (December 31, 2006 - $6,767) of future capital costs and excluded $13,380 (December 31, 2006 – $8,220) of unproved property costs.

During the year ended December 31, 2007, $2,004 (year ended December 31, 2006 – $1,627) of administrative costs relating to exploration and development activities were capitalized as part of property, plant and equipment.

At December 31, 2007, the Company applied the ceiling test calculation to its petroleum and natural gas properties using expected future market prices. These expected future market prices were forecast by the Company's independent reserve evaluators and then adjusted for commodity price differentials specific to the Company's production. The following table exhibits the benchmark prices used in the ceiling test:

	Oil WTI (Cushing, Oklahoma) (US$/bbl)	Oil Edmonton par (40 API) (CDN$/bbl)	Natural Gas AECE-C Spot Price (CDN$/mmbtu)	Heavy Oil at Hardisty (12° API) (CDN$/bbl)	Currency Exchange Rate (US$/CDN$)
2008	92.00	91.10	6.75	54.02	1.00
2009	88.00	87.10	7.55	51.61	1.00
2010	84.00	83.10	7.60	49.19	1.00
2011	82.00	81.10	7.60	47.98	1.00
2012	82.00	81.10	7.60	47.98	1.00
2013	82.00	81.10	7.60	49.04	1.00
2014	82.00	81.10	7.80	50.09	1.00
2015	82.00	81.10	7.97	51.15	1.00
2016	82.02	81.12	8.14	52.21	1.00
2017	83.66	82.76	8.31	53.29	1.00
2018	85.33	84.42	8.48	54.36	1.00
Thereafter (escalation)	2.0%/yr	2.0%/yr	2.0%/yr	2.0%/yr	1.00

6. Bank Debt

At December 31, 2007 the Company had a demand operating facility with a Canadian chartered bank subject to the bank's valuation of the Company's oil and natural gas properties. The limit under the facility at December 31, 2007 was $36 million. The facility is secured by a first ranking floating charge on all real property of the Company, its subsidiary and partnership and a general security agreement. The facility bears interest at the bank's prime rate or at prevailing bankers' acceptance rate plus an applicable bank fee, which varies depending on the Company's debt-to-funds from operations ratio. The facility also bears a standby charge for un-drawn amounts. The next review is to be completed before April 30, 2008

7. Asset Retirement Obligation

The Company's asset retirement obligations result from net ownership interests in petroleum and natural gas assets including well sites, gathering systems and processing facilities. The Company estimates the total undiscounted amount of cash flows required to settle its asset retirement obligations at December 31, 2007 was approximately $6,474 (December 31, 2006 – $3,666), which will be incurred between 2008 and 2020. A credit-adjusted risk-free rate of 8 percent and an annual inflation rate of 1.5 percent were used to calculate the future asset retirement obligation.

	December 31, 2007	December 31, 2006
Balance, beginning of year	$ 2,094	$ 2,115
Liabilities incurred/acquired during year	1,592	413
Dispositions	-	(459)
Accretion	154	129
Actual retirement costs	-	(104)
Balance, end of year	$ 3,840	$ 2,094

8. Share Capital

(A) AUTHORIZED:

Unlimited number of voting common shares, without stated par value.

300,000 preference shares, without stated par value.

(B) COMMON SHARES ISSUED:

Common Shares of Rock	Number	Amount ($000)
Issued and outstanding as at December 31, 2005	19,637,321	$ 57,369
Future tax effect of flow-through share renouncements *(i)*		(43)
Issued and outstanding as at December 31, 2006	19,637,321	$ 57,326
Issued for flow-through shares *(ii)*	10,007	42
Issued in private placement	2,998,623	12,144
Issued for property acquisitions	3,143,167	11,818
Issued for flow-through shares *(iii)*	88,524	270
Issued and outstanding as at December 31, 2007	25,877,642	$ 81,600

(i) In accordance with the Company's stock option plan, some options were exercised in exchange for flow-through shares of the Company; by February 2, 2006 all of the renouncements were made.

(ii) In accordance with the Company's stock option plan, some options were exercised in exchange for flow-through shares of the Company.

(iii) The Company issued flow-through shares to employees.

(C) STOCK OPTIONS

The Company has a stock option plan under which it may grant options to directors, officers and employees for the purchase of up to 10 percent of the issued and outstanding common shares of the Company. Options are granted at the discretion of the board of directors. The exercise price, vesting period and expiration period are also fixed at the time of grant at the discretion of the board of directors. The majority of options vest yearly in one-third tranches beginning on the first anniversary of the grant date and expire one year after vesting. Options expiring are usually replaced with another grant that vests in two years and expires in three years. At the Company's discretion the options can be exercised for cash. The following table summarizes the status of the Company's stock option plan as at December 31, 2007 and December 31, 2006 and changes during the year ended on those dates:

	December 31, 2007		December 31, 2006	
	Options	Weighted-Average Exercise Price ($)	Options	Weighted-Average Exercise Price ($)
Outstanding, beginning of year	1,767,277	$4.19	1,120,332	$ 4.51
Granted	1,258,366	$2.79	677,779	$ 3.66
Exercised	(82,485)	$3.49	-	-
Forfeited	(286,890)	$4.23	-	-
Expired	(348,446)	$4.36	(30,834)	$ 3.87
Outstanding, end of year	2,307,822	$3.42	1,767,277	$ 4.19

Options outstanding and exercisable under the stock option plan are summarized below as at December 31, 2007:

	Outstanding Options			Exercisable Options	
	Number of Options	Weighted-Average Exercise Price	Weighted-Average Years to Expiry	Number of Options	Weighted-Average Exercise Price ($)
$2.43 - $3.41	1,634,870	$ 2.87	2.50	150,130	$ 3.25
$3.78 - $5.11	672,952	$ 4.76	1.10	347,955	$ 4.78
	2,307,822	$ 3.42	2.09	498,085	$ 4.32

(D) PER SHARE AMOUNTS

The weighted average number of common shares outstanding during the year ended December 31, 2007 of 21,238,886 (year ended December 31, 2006 – 19,637,321) was used to calculate per share amounts. To calculate diluted common shares outstanding, the treasury method was used. Under this method, in-the-money options are assumed exercised and the proceeds used to repurchase shares at the year-end date of December 31, 2007. As at December 31, 2007 no additional (December 31, 2006 – 17,660) common shares were used to calculate diluted earnings per share.

9. Stock-Based Compensation

Options granted to employees and non-employees after March 31, 2003 are accounted for using the fair value method. The fair value of common share options granted for the year ended December 31, 2007 was estimated to be $1,434 (year ended December 31, 2006 – $976) as at the grant date using the Black-Scholes option pricing model and the following assumptions:

Risk-free interest rate	4.00% - 6.25%
Expected life	Three-year average
Expected volatility	30% - 60%
Expected dividend yield	0%

The estimated fair value of the options is amortized to expense and credited to contributed surplus over the option vesting period on a straight-line basis. The change in the contributed surplus account is reconciled in the table below:

	December 31, 2007	December 31, 2006
Balance, beginning of year	$ 1,641	$ 453
Stock-based compensation expense	931	1,188
Net benefit on options exercised[1]	(51)	-
Balance, end of year	$ 2,521	$ 1,641

(1) The benefit of options exercised is recorded as a reduction of contributed surplus and an increase to share capital.

10. Income Taxes

The provision for income taxes in the consolidated statements of operations and retained earnings varies from the amount that would be computed by applying the expected tax rate to net income before income taxes. The expected tax rate used was 32.40 percent (December 31, 2006 – 33.70 percent). The principal reasons for differences between such "expected" income tax expense and the amount actually recorded are as follows:

	December 31, 2007	December 31, 2006
Net income before income taxes	$ 191	$ (1,290)
Statutory income tax rate	32.4%	33.7%
Expected income taxes	$ 62	$ (435)
Add (deduct):		
Stock-based compensation	302	400
Non-deductible Crown charges	-	330
Change in enacted rates	(365)	(311)
Other	(375)	180
Resource allowance	-	(615)
Change in valuation allowance	(70)	-
Provision for income taxes	$ (446)	$ (451)
Capital tax	76	45
Provision for (recovery of) income taxes	$ (370)	$ (406)

Future income tax assets or liabilities recognized on the consolidated balance sheets are comprised of temporary differences. The after-tax effect of these temporary differences are summarized as follows:

	December 31, 2007	December 31, 2006
Loss carry-forwards	$ 4,587	$ 4,941
Property, plant and equipment	(2,070)	(6,218)
Non-coterminous year-ends	(4,808)	(3,859)
Share issuance costs	331	263
Asset retirement obligation	1,075	649
Calculated future income tax liability	(885)	(4,224)
Valuation allowance	(648)	(718)
Future income taxes (liability)	$ (1,533)	$ (4,942)

At December 31, 2007, Rock and its subsidiaries had tax pools totalling $122.9 million prior to the allocation of deferred partnership income and $106.1 million (December 31, 2006 – $55.2 million) after the allocation of deferred partnership income. The non-capital losses prior to the allocation of deferred partnership income expire as follows:

2014	$ 1,320
2015	1,031
2026	8,323
2027	3,830
	$ 14,504

11. Financial Instruments

Rock's financial instruments included in the consolidated balance sheets are comprised of cash and cash equivalents, accounts receivable, refundable deposits, bank debt, accounts payable and accrued liabilities and income taxes payable. The fair values of these financial instruments approximate their carrying amount due to the short-term nature of the instruments. A substantial portion of Rock's accounts receivable are with customers in the oil and natural gas industry and are subject to normal industry credit risks. Interest rates directly impact interest costs as the Company's current debt facility is based on floating rates. Crude oil sales are referenced to the U.S. dollar, thus the Canadian price realized is directly impacted by Canadian and U.S. dollar exchange rates.

12. Commitments

Obligations with a fixed term are as follows:

	2008	2009	2010	2011	2012
Lease of office premises	$ 895	$ 828	$ 828	$ 828	$ 552
Processing arrangements	$ 450	$ 360	$ 288	$ 238	$ 159

Advisory

Certain statements and information contained in this press release, including but not limited to management's assessment of Rock's future plans and operations, production, reserves, revenue, commodity prices, operating and administrative expenditures, funds from operations, capital expenditure programs and debt levels contain forward-looking statements. All statements other than statements of historical fact may be forward looking statements. These statements, by their nature, are subject to numerous risks and uncertainties, some of which are beyond Rock's control including the effect of general economic conditions, industry conditions, changes in regulatory and taxation regimes, volatility of commodity prices, escalation of operating and capital costs, currency fluctuations, the availability of services, imprecision of reserve estimates, geological, technical, drilling and processing problems, environmental risks, weather, the lack of availability of qualified personnel or management, stock market volatility, the ability to access sufficient capital from internal and external sources and competition from other industry participants for, among other things, capital, services, acquisitions of reserves, undeveloped lands and skilled personnel that may cause actual results or events to differ materially from those anticipated in the forward looking statements. Such forward-looking statements, although considered reasonable by management at the time of preparation, may prove to be incorrect and actual results may differ materially from those anticipated in the statements made and should not unduly be relied on. These statements speak only as of the date of this press release. Rock does not intend and does not assume any obligation to update these forward-looking statements, whether as a result of new information, future events or otherwise, except as required by applicable law.

This press release contains references to barrels of oil equivalent (boe), boes maybe misleading, particularly if used in isolation. A boe conversion of 6 mcf to 1 barrel of oil is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

For further information please visit our website at www.rockenergy.ca or contact:

Allen Bey
President & CEO
(403) 218-4380

or

Peter D. Scott
Vice President, Finance & CFO
(403) 218-4380

rockenergy

File No. 82-34785

FORM 52-109F1

CERTIFICATION OF ANNUAL FILINGS

I, Allen J. Bey, President and CEO of Rock Energy Inc., certify that:

1. I have reviewed the annual filings (as this term is defined in Multilateral Instrument 52- 109 *Certification of Disclosure in Issuers' Annual and Interim Filings*) of Rock Energy Inc. (the issuer) for the period ending December 31, 2007;

2. Based on my knowledge, the annual filings do not contain any untrue statement of a material fact or omit to state a material fact required to be stated or that is necessary to make a statement not misleading in light of the circumstances under which it was made, with respect to the period covered by the annual filings;

3. Based on my knowledge, the annual financial statements together with the other financial information included in the annual filings fairly present in all material respects the financial condition, results of operations and cash flows of the issuer, as of the date and for the periods presented in the annual filings;

4. The issuer's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures and internal control over financial reporting for the issuer, and we have:

   (a) designed such disclosure controls and procedures, or caused them to be designed under our supervision, to provide reasonable assurance that material information relating to the issuer, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which the annual filings are being prepared;

   (b) designed such internal control over financial reporting, or caused it to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with the issuer's GAAP; and

   (c) evaluated the effectiveness of the issuer's disclosure controls and procedures as of the end of the period covered by the annual filings and have caused the issuer to disclose in the annual MD&A our conclusions about the effectiveness of the disclosure controls and procedures as of the end of the period covered by the annual filings based on such evaluation; and

5. I have caused the issuer to disclose in the annual MD&A any change in the issuer's internal control over financial reporting that occurred during the issuer's most recent interim period that has materially affected, or is reasonably likely to materially affect, the issuer's internal control over financial reporting.

Date: March 12, 2008

"signed"
Allen J. Bey
President and CEO

File No. 82-34785

rockenergy

FORM 52-109F1

CERTIFICATION OF ANNUAL FILINGS

I, Peter D. Scott, Vice President, Finance and CFO of Rock Energy Inc., certify that:

1. I have reviewed the annual filings (as this term is defined in Multilateral Instrument 52- 109 *Certification of Disclosure in Issuers' Annual and Interim Filings*) of Rock Energy Inc. (the issuer) for the period ending December 31, 2007;

2. Based on my knowledge, the annual filings do not contain any untrue statement of a material fact or omit to state a material fact required to be stated or that is necessary to make a statement not misleading in light of the circumstances under which it was made, with respect to the period covered by the annual filings;

3. Based on my knowledge, the annual financial statements together with the other financial information included in the annual filings fairly present in all material respects the financial condition, results of operations and cash flows of the issuer, as of the date and for the periods presented in the annual filings;

4. The issuer's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures and internal control over financial reporting for the issuer, and we have:

   (a) designed such disclosure controls and procedures, or caused them to be designed under our supervision, to provide reasonable assurance that material information relating to the issuer, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which the annual filings are being prepared;

   (b) designed such internal control over financial reporting, or caused it to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with the issuer's GAAP; and

   (c) evaluated the effectiveness of the issuer's disclosure controls and procedures as of the end of the period covered by the annual filings and have caused the issuer to disclose in the annual MD&A our conclusions about the effectiveness of the disclosure controls and procedures as of the end of the period covered by the annual filings based on such evaluation; and

5. I have caused the issuer to disclose in the annual MD&A any change in the issuer's internal control over financial reporting that occurred during the issuer's most recent interim period that has materially affected, or is reasonably likely to materially affect, the issuer's internal control over financial reporting.

Date: March 12, 2008

"signed"

Peter D. Scott
Vice President, Finance and CFO

rockenergy

File No. 82-34785

Management's Report

To the Shareholders of Rock Energy Inc.:

The financial statements of Rock Energy Inc. were prepared by management in accordance with appropriately selected generally accepted accounting principles in Canada. Management has used estimates and careful judgement, particularly in those circumstances where transactions affecting current periods are dependent on information not known until a future period. The financial and operational infonnation contained in this annual report is consistent with that reported in the financial statements.

Management is responsible for the integrity of the financial and operational information contained in this report. The Company has designed and maintains internal controls to provide reasonable assurance that assets are properly safeguarded and that the financial records are well maintained and provide relevant, timely and reliable information to management. The financial statements have been prepared within reasonable limits of materiality and within the framework of the significant accounting policies summarized in the notes to the financial statements.

External auditors appointed by the shareholders have conducted an independent examination of the corporate and accounting records in order to express their opinion on the financial statements. The Audit Committee has met with the external auditors and management in order to determine if management has fulfilled its responsibilities in the preparation of the financial statements. The Board of Directors has approved the financial statements on the recommendation of the Audit Committee.

Allen J. Bey
President and Chief Executive Officer
March 12, 2008

Peter D. Scott
Vice President, Finance and Chief Financial Officer
March 12, 2008

Auditors' Report

We have audited the consolidated balance sheets of Rock Energy Inc. as at December 31, 2007 and 2006 and the consolidated statements of income (loss), comprehensive income (loss) and retained earnings and cash flows for the years then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2007 and 2006 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

KPMG LLP

Chartered Accountants

Calgary, Canada
March 12, 2007

Consolidated Balance Sheets
(000s of dollars)

As at	December 31, 2007	December 31, 2006
Assets		
Current assets		
Accounts receivable	$ 8,473	$ 4,753
Prepaid expenses	1,383	532
	9,856	5,285
Property, plant and equipment *(note 5)*	151,762	97,229
Accumulated depletion and depreciation	(36,871)	(22,882)
	114,891	74,347
Goodwill	5,748	5,748
	$ 130,495	$ 85,380
Liabilities and Shareholders' Equity		
Current liabilities		
Accounts payable and accrued liabilities	$ 11,523	$ 6,900
Bank debt *(note 6)*	27,405	10,965
	38,928	17,865
Future tax liability *(note 10)*	1,533	4,942
Asset retirement obligation *(note 7)*	3,840	2,094
Shareholders' equity		
Share capital *(note 8)*	81,600	57,326
Contributed surplus *(note 9)*	2,521	1,641
Retained earnings	2,073	1,512
	86,194	60,479
Commitments *(note 12)*		
	$ 130,495	$ 85,380

See accompanying notes to consolidated financial statements.

Approved by the Board:

James K. Wilson
Director

Allen J. Bey
Director

Consolidated Statements of Income (Loss), Comprehensive Income (Loss) and Retained Earnings

(000s of dollars, except per share amounts)

Years ended	December 31, 2007	December 31, 2006
Revenues:		
Oil and natural gas revenue	$ 36,042	$ 33,156
Royalties	(7,035)	(6,881)
Other income	79	198
	29,086	26,473
Expenses:		
General and administrative	2,739	2,278
Operating	9,925	9,255
Interest	1,157	924
Stock-based compensation *(note 9)*	931	1,188
Depletion, depreciation, and accretion	14,143	14,118
	28,895	27,763
Income (loss) before taxes	191	(1,290)
Taxes		
Provincial capital taxes *(note 10)*	76	45
Future income taxes (reduction) *(note 10)*	(446)	(451)
Net income (loss) and comprehensive income (loss) for the year	561	(884)
Retained earnings, beginning of year	1,512	2,396
Retained earnings, end of year	$ 2,073	$ 1,512
Diluted and basic net income (loss) per share *(note 8)*	$ 0.03	$ (0.05)

See accompanying notes to consolidated financial statements.

Consolidated Statements of Cash Flows

(000s of dollars)

Years ended	December 31, 2007	December 31, 2006
Cash provided by (used in):		
Operating:		
Net income (loss) for the year	$ 561	$ (884)
Add: Non-cash items:		
Depletion, depreciation, and accretion	14,143	14,118
Actual abandonment costs	-	(104)
Stock-based compensation	931	1,188
Future income taxes (reduction)	(446)	(451)
	15,189	13,867
Changes in non-cash working capital	(1,035)	2,571
	14,154	16,438
Financing:		
Issuance of common shares	12,456	-
Bank debt	10,903	(12,011)
Repurchase of stock options	(51)	-
	23,308	(12,011)
Investing:		
Property, plant and equipment	(25,575)	(32,879)
Acquisition of property, plant and equipment *(note 4)*	(12,644)	-
Disposition of property, plant and equipment	-	30,874
Changes in non-cash working capital	757	(2,567)
	(37,462)	(4,572)
Decrease in cash and cash equivalents	-	(145)
Cash and cash equivalents, beginning of year	-	145
Cash and cash equivalents, end of year	$ -	$ -
Interest and taxes paid and received:		
Interest paid	$ 1,190	$ 960
Interest received	34	32
Taxes paid	142	25

See accompanying notes to consolidated financial statements.

Years ended December 31, 2007 and 2006

1. Nature of Operations

Rock Energy Inc. (the "Company" or "Rock") is actively engaged in the exploration, production and development of oil and natural gas in Western Canada.

2. Significant Accounting Policies

The consolidated financial statements of Rock are stated in Canadian dollars and have been prepared in accordance with Canadian generally accepted accounting principles (GAAP).

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amount of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the period. Actual results could differ from those estimates.

(A) CONSOLIDATION

These consolidated financial statements include the accounts of Rock Energy Inc., Rock Energy Ltd. and Rock Energy Production Partnership. All inter-company transactions and balances have been eliminated upon consolidation.

(B) CASH AND CASH EQUIVALENTS

Cash and cash equivalents are comprised of cash and short-term investments with a maturity date of 12 months or less.

(C) JOINT OPERATIONS

A substantial portion of the Company's oil and natural gas exploration and development activities is conducted jointly with others and, accordingly, these consolidated financial statements reflect only the Company's proportionate interest in such activities.

(D) PROPERTY, PLANT AND EQUIPMENT

Capitalized costs: The Company follows the full cost method of accounting for its oil and natural gas operations, whereby all costs related to the acquisition, exploration and development of petroleum and natural gas reserves are capitalized. Such costs include lease acquisition costs, geological and geophysical costs, carrying charges on non-producing properties, costs of drilling both productive and non-productive wells, the cost of petroleum and natural gas production equipment and overhead charges directly related to exploration and development activities. Proceeds from the sale of oil and natural gas properties are applied against capital costs, with no gain or loss recognized, unless such a sale would change the rate of depletion and depreciation by 20 percent or more, in which case a gain or loss would be recorded.

Depletion, depreciation and amortization: The capitalized costs are depleted and depreciated using the unit-of-production method based on proved petroleum and natural gas reserves, as determined by independent consulting engineers. Oil and natural gas liquids reserves and production are converted into equivalent units of natural gas based on relative energy content. Office furniture and equipment are recorded at cost and depreciated on a declining balance basis using a rate of 20 percent.

Ceiling test: Rock calculates its ceiling test by comparing the carrying value of oil and natural gas properties and production equipment to the sum of undiscounted cash flows from proved reserves. If the carrying value is not fully recoverable, the amount of impairment is measured by comparing the carrying value of property and equipment to the estimated net present value of future cash flows from proved plus probable reserves, using a risk-free interest rate and expected future prices, and unproved properties. Any excess carrying value above the net present value of the future cash flows is recorded as a permanent impairment.

Asset retirement obligations: The Company records the fair value of an asset retirement obligation (ARO) as a liability in the period in which it incurs a legal obligation to restore an oil and natural gas property, typically when a well is drilled or other equipment is put in place. The associated asset retirement costs are capitalized as part of the carrying amount of the related asset and depleted on a unit-of-production method over the life of the proved reserves. Subsequent to initial measurement of the obligations, the obligations are adjusted at the end of each reporting period to reflect the passage of time and changes in estimated future cash flows underlying the obligation. Actual costs incurred on settlement of the ARO are charged against the ARO.

(E) GOODWILL

Goodwill is the residual amount that results when the purchase price of an acquired business exceeds the fair value for accounting purposes of the net identifiable assets and liabilities of the acquired business. Goodwill is stated at cost less any impairment and is not amortized. The goodwill balance is subject to an impairment test whereby the book value of the Company's equity is compared to its fair value. If the fair value of the Company's equity is less than book value, impairment is measured by allocating the fair value of the identifiable assets and liabilities at their fair values. The difference between the Company's fair value and book value of identifiable assets and liabilities is the fair value of goodwill. Any excess of the book value of goodwill over the implied fair value of goodwill is the impairment amount. Impairment is charged to income in the period in which it occurs. The impairment test is carried out annually, or more frequently if circumstances occur that are more likely than not to reduce the fair value of the acquired business below its carrying amount.

(F) INCOME TAXES

Income taxes are calculated using the asset and liability method of tax accounting. Temporary differences arising from the difference between the tax basis of an asset or liability and its carrying value on the balance sheet are used to calculate future income tax assets and liabilities. Future income tax assets and liabilities are calculated using tax rates anticipated to apply in the periods when the temporary differences are expected to reverse.

(G) FLOW-THROUGH SHARES

The resource expenditure deductions for income tax purposes related to exploratory and development activities funded by flow-through share arrangements are renounced to investors in accordance with income tax legislation. Future tax liabilities and share capital are adjusted by the estimated cost of the renounced tax deduction when the expenses are renounced.

(H) STOCK-BASED COMPENSATION

The Company grants options to purchase common shares to employees and directors under its stock option plan. Awards are accounted for using the fair value of accounting for stock-based compensation. Under the fair value method, an estimate of the value of the option is determined at the time of grant using the Black-Scholes option pricing model. The fair value of the option is recognized as an expense and contributed surplus over the vested life of the option.

(I) REVENUE RECOGNITION

Revenue from the sale of oil and natural gas is recognized based on volumes delivered to customers at contractual delivery points and rates.

(J) MEASUREMENT UNCERTAINTY

The amounts recorded for depletion and depreciation of property, plant and equipment, the provision for asset retirement obligations, the amounts used for ceiling test calculations and fair value of identifiable assets for goodwill impairment are based on estimates of reserves and future costs. The Company's reserve estimates are reviewed annually by an independent engineering firm. The amounts disclosed relating to fair values of stock options issued are based on estimates of future volatility of the Company's share price, expected lives of options, and other relevant assumptions. By their nature, these estimates are subject to measurement uncertainty and the impact on the consolidated financial statements of changes in such estimates in future periods could be material.

(K) PER SHARE AMOUNTS

Basic per share amounts are calculated using the weighted average number of shares outstanding during the year. Diluted per share amounts are calculated based on the treasury stock method whereby the weighted average number of shares is adjusted for the dilutive effect of options.

3. Accounting Policies Changes and Pending Changes

(A) FINANCIAL INSTRUMENTS

As of January 1, 2007 the Company adopted new policies to implement the pronouncements from the Canadian Institute of Chartered Accountants (CICA) in respect of financial instruments – presentation and disclosures, hedging and other comprehensive income. The application of these policies did not result in changes to amounts reported in the consolidated financial statements for the year ended December 31, 2007.

On initial recognition all financial instruments, including derivatives, are recorded at fair value and subsequent measurement is based on the financial instruments classification: held for trading, held to maturity, loans and receivables, available for sale and other liabilities.

The Company has designated its cash and cash equivalents as held for trading which are measured at fair value. Accounts receivable are classified as loans and receivables which are measured at amortized cost. Accounts payable and accrued liabilities and bank debt are classified as other liabilities which are measured at amortized cost, using the effective interest method.

The Company is exposed to fluctuations in commodity prices, foreign exchange rates and interest rates. Derivative instruments may be used by the Company to reduce its exposure to fluctuations in commodity prices, foreign exchange rates, and interest rates. If derivatives instruments were used they would be classified as held for trading and recorded on the balance sheet at fair value, with changes in the fair value recognized in income, unless specific hedge criteria were met. The fair values of derivative instruments would be based on an estimate of the amounts that would have been received or paid to settle these instruments prior to maturity. Proceeds and costs realized from holding derivative instruments would be recognized in income at the time each transaction under a contract was settled.

The Company has elected to account for its physical delivery sales contracts, which were entered into and continue to be held for the purpose of receipt or delivery of non-financial items in accordance with its expected purchase, sale or usage requirements as executory contracts on an accrual basis rather than as non-financial derivatives instruments.

The Company measures and recognizes embedded derivatives separately from the host contracts when the economic characteristics and risks of the embedded derivative are not closely related to those of the host contract, when it meets the definition of a derivative and when the entire contract is not measured at fair value. Embedded derivatives are recorded at fair value.

The Company applies trade-date accounting for the recognition of a purchase or sale of cash equivalents and derivative instruments. The Company expenses all transaction costs incurred in relation to the acquisition of a financial asset or liability.

The CICA has issued two new financial instruments standards: Section 3862, Financial Instruments - Disclosures, and Section 3863, Financial Instruments - Presentation. The new disclosure standards effective January 1, 2008 may increase the Company's disclosures on risks related to financial instruments and how those risks are managed.

(B) COMPREHENSIVE INCOME

A new standard adopted requires statements of comprehensive income and accumulated other comprehensive income to temporarily provide for gains, losses and other amounts arising from changes in fair value until they are realized and recorded in income. The Company had no items that would affect comprehensive income or accumulated other comprehensive income for the year ended December 31, 2007.

(C) CAPITAL DISCLOSURES

As of January 1, 2008, the Company will be required to adopt Section 1535, Capital Disclosures, which require disclosure of the Company's objectives, policies and processes for managing capital.

(D) GOODWILL

As of January 1, 2009, the Company will be required to adopt Section 3064, Goodwill and Intangible Assets, which defines the criteria for the recognition of intangible assets.

(E) INTERNATIONAL REPORTING STANDARDS

The CICA has confirmed the effective date of January 1, 2001 for the convergence of Canadian GAAP to International Financial Reporting Standards. The Canadian Securities Administrators are currently examining changes to securities laws as a consequence of this initiative.

4. Acquisition of Greenbank Energy Ltd.

On July 31, 2007 the Company agreed to acquire a private company by way of a plan of arrangement for cash and shares of the Company. The transaction closed on September 28, 2007 and has been accounted for using the purchase method and the results of operations for the transaction are included in the financial statements beginning in the fourth quarter of 2007.

The purchase price equation is as follows:

($000)

Property, plant and equipment	$ 28,127
Bank debt	(5,537)
Working capital deficiency	(330)
Asset retirement obligation	(761)
Future income tax asset	2,963
	$ 24,462
Consideration provided:	
Cash from private placement	$ 12,144
Common shares (3,143,167)	11,818
Transaction costs	500
	$ 24,462

The preliminary purchase price allocations were based on certain estimates such as the fair values of the assets and liabilities as of the closing date. The items to be finalized in the purchase price allocation relate to working capital deficiency and transaction costs.

5. Property, Plant and Equipment

($000)	December 31, 2007	December 31, 2006
Petroleum and natural gas properties	**$ 150,408**	$ 96,887
Other assets	**1,354**	342
	151,762	97,229
Accumulated depletion and depreciation	**(36,871)**	(22,882)
	$ 114,891	$ 74,347

At December 31, 2007, the depletable base for the petroleum and natural gas properties included $14,404 (December 31, 2006 - $6,767) of future capital costs and excluded $13,380 (December 31, 2006 – $8,220) of unproved property costs.

During the year ended December 31, 2007, $2,004 (year ended December 31, 2006 – $1,627) of administrative costs relating to exploration and development activities were capitalized as part of property, plant and equipment.

At December 31, 2007, the Company applied the ceiling test calculation to its petroleum and natural gas properties using expected future market prices. These expected future market prices were forecast by the Company's independent reserve evaluators and then adjusted for commodity price differentials specific to the Company's production. The following table exhibits the benchmark prices used in the ceiling test:

	Oil WTI (Cushing, Oklahoma) (US$/bbl)	Oil Edmonton par (40 API) (CDN$/bbl)	Natural Gas AECE-C Spot Price (CDN$/mmbtu)	Heavy Oil at Hardisty (12° API) (CDN$/bbl)	Currency Exchange Rate (US$/CDN$)
2008	92.00	91.10	6.75	54.02	1.00
2009	88.00	87.10	7.55	51.61	1.00
2010	84.00	83.10	7.60	49.19	1.00
2011	82.00	81.10	7.60	47.98	1.00
2012	82.00	81.10	7.60	47.98	1.00
2013	82.00	81.10	7.60	49.04	1.00
2014	82.00	81.10	7.80	50.09	1.00
2015	82.00	81.10	7.97	51.15	1.00
2016	82.02	81.12	8.14	52.21	1.00
2017	83.66	82.76	8.31	53.29	1.00
2018	85.33	84.42	8.48	54.36	1.00
Thereafter (escalation)	2.0%/yr	2.0%/yr	2.0%/yr	2.0%/yr	1.00

6. Bank Debt

At December 31, 2007 the Company had a demand operating facility with a Canadian chartered bank subject to the bank's valuation of the Company's oil and natural gas properties. The limit under the facility at December 31, 2007 was $36 million. The facility is secured by a first ranking floating charge on all real property of the Company, its subsidiary and partnership and a general security agreement. The facility bears interest at the bank's prime rate or at prevailing bankers' acceptance rate plus an applicable bank fee, which varies depending on the Company's debt-to-funds from operations ratio. The facility also bears a standby charge for un-drawn amounts. The next review is to be completed before April 30, 2008

7. Asset Retirement Obligation

The Company's asset retirement obligations result from net ownership interests in petroleum and natural gas assets including well sites, gathering systems and processing facilities. The Company estimates the total undiscounted amount of cash flows required to settle its asset retirement obligations at December 31, 2007 was approximately $6,474 (December 31, 2006 – $3,666), which will be incurred between 2008 and 2020. A credit-adjusted risk-free rate of 8 percent and an annual inflation rate of 1.5 percent were used to calculate the future asset retirement obligation.

	December 31, 2007	December 31, 2006
Balance, beginning of year	**$ 2,094**	$ 2,115
Liabilities incurred/acquired during year	**1,592**	413
Dispositions	**-**	(459)
Accretion	**154**	129
Actual retirement costs	**-**	(104)
Balance, end of year	**$ 3,840**	$ 2,094

8. Share Capital

(A) AUTHORIZED:

Unlimited number of voting common shares, without stated par value.

300,000 preference shares, without stated par value.

(B) COMMON SHARES ISSUED:

Common Shares of Rock	Number	Amount ($000)
Issued and outstanding as at December 31, 2005	19,637,321	$ 57,369
Future tax effect of flow-through share renouncements *(i)*		(43)
Issued and outstanding as at December 31, 2006	19,637,321	$ 57,326
Issued for flow-through shares *(ii)*	10,007	42
Issued in private placement	2,998,623	12,144
Issued for property acquisitions	3,143,167	11,818
Issued for flow-through shares *(iii)*	88,524	270
Issued and outstanding as at December 31, 2007	25,877,642	$ 81,600

(i) In accordance with the Company's stock option plan, some options were exercised in exchange for flow-through shares of the Company; by February 2, 2006 all of the renouncements were made.

(ii) In accordance with the Company's stock option plan, some options were exercised in exchange for flow-through shares of the Company.

(iii) The Company issued flow-through shares to employees.

(C) STOCK OPTIONS

The Company has a stock option plan under which it may grant options to directors, officers and employees for the purchase of up to 10 percent of the issued and outstanding common shares of the Company. Options are granted at the discretion of the board of directors. The exercise price, vesting period and expiration period are also fixed at the time of grant at the discretion of the board of directors. The majority of options vest yearly in one-third tranches beginning on the first anniversary of the grant date and expire one year after vesting. Options expiring are usually replaced with another grant that vests in two years and expires in three years. At the Company's discretion the options can be exercised for cash. The following table summarizes the status of the Company's stock option plan as at December 31, 2007 and December 31, 2006 and changes during the year ended on those dates:

	December 31, 2007		December 31, 2006	
	Options	**Weighted-Average Exercise Price ($)**	Options	Weighted-Average Exercise Price ($)
Outstanding, beginning of year	**1,767,277**	**$4.19**	1,120,332	$ 4.51
Granted	**1,258,366**	**$2.79**	677,779	$ 3.66
Exercised	**(82,485)**	**$3.49**	-	-
Forfeited	**(286,890)**	**$4.23**	-	-
Expired	**(348,446)**	**$4.36**	(30,834)	$ 3.87
Outstanding, end of year	**2,307,822**	**$3.42**	1,767,277	$ 4.19

Options outstanding and exercisable under the stock option plan are summarized below as at December 31, 2007:

	Outstanding Options			Exercisable Options	
	Number of Options	Weighted-Average Exercise Price	Weighted-Average Years to Expiry	Number of Options	Weighted-Average Exercise Price ($)
$2.43 - $3.41	1,634,870	$ 2.87	2.50	150,130	$ 3.25
$3.78 - $5.11	672,952	$ 4.76	1.10	347,955	$ 4.78
	2,307,822	$ 3.42	2.09	498,085	$ 4.32

(D) PER SHARE AMOUNTS

The weighted average number of common shares outstanding during the year ended December 31, 2007 of 21,238,886 (year ended December 31, 2006 – 19,637,321) was used to calculate per share amounts. To calculate diluted common shares outstanding, the treasury method was used. Under this method, in-the-money options are assumed exercised and the proceeds used to repurchase shares at the year-end date of December 31, 2007. As at

December 31, 2007 no additional (December 31, 2006 – 17,660) common shares were used to calculate diluted earnings per share.

9. Stock-Based Compensation

Options granted to employees and non-employees after March 31, 2003 are accounted for using the fair value method. The fair value of common share options granted for the year ended December 31, 2007 was estimated to be $1,434 (year ended December 31, 2006 – $976) as at the grant date using the Black-Scholes option pricing model and the following assumptions:

Risk-free interest rate	4.00% - 6.25%
Expected life	Three-year average
Expected volatility	30% - 60%
Expected dividend yield	0%

The estimated fair value of the options is amortized to expense and credited to contributed surplus over the option vesting period on a straight-line basis. The change in the contributed surplus account is reconciled in the table below:

	December 31, 2007	December 31, 2006
Balance, beginning of year	$ 1,641	$ 453
Stock-based compensation expense	931	1,188
Net benefit on options exercised[1]	(51)	-
Balance, end of year	$ 2,521	$ 1,641

(1) The benefit of options exercised is recorded as a reduction of contributed surplus and an increase to share capital.

10. Income Taxes

The provision for income taxes in the consolidated statements of operations and retained earnings varies from the amount that would be computed by applying the expected tax rate to net income before income taxes. The expected tax rate used was 32.40 percent (December 31, 2006 – 33.70 percent). The principal reasons for differences between such "expected" income tax expense and the amount actually recorded are as follows:

	December 31, 2007	December 31, 2006
Net income before income taxes	$ 191	$ (1,290)
Statutory income tax rate	32.4%	33.7%
Expected income taxes	$ 62	$ (435)
Add (deduct):		
Stock-based compensation	302	400
Non-deductible Crown charges	-	330
Change in enacted rates	(365)	(311)
Other	(375)	180
Resource allowance	-	(615)
Change in valuation allowance	(70)	-
Provision for income taxes	$ (446)	$ (451)
Capital tax	76	45
Provision for (recovery of) income taxes	$ (370)	$ (406)

Future income tax assets or liabilities recognized on the consolidated balance sheets are comprised of temporary differences. The after-tax effect of these temporary differences are summarized as follows:

	December 31, 2007	December 31, 2006
Loss carry-forwards	$ 4,587	$ 4,941
Property, plant and equipment	(2,070)	(6,218)
Non-coterminous year-ends	(4,808)	(3,859)
Share issuance costs	331	263
Asset retirement obligation	1,075	649
Calculated future income tax liability	(885)	(4,224)
Valuation allowance	(648)	(718)
Future income taxes (liability)	$ (1,533)	$ (4,942)

At December 31, 2007, Rock and its subsidiaries had tax pools totalling $122.9 million prior to the allocation of deferred partnership income and $106.1 million (December 31, 2006 – $55.2 million) after the allocation of deferred partnership income. The non-capital losses prior to the allocation of deferred partnership income expire as follows:

2014	$ 1,320
2015	1,031
2026	8,323
2027	3,830
	$ 14,504

11. Financial Instruments

Rock's financial instruments included in the consolidated balance sheets are comprised of cash and cash equivalents, accounts receivable, refundable deposits, bank debt, accounts payable and accrued liabilities and income taxes payable. The fair values of these financial instruments approximate their carrying amount due to the short-term nature of the instruments. A substantial portion of Rock's accounts receivable are with customers in the oil and natural gas industry and are subject to normal industry credit risks. Interest rates directly impact interest costs as the Company's current debt facility is based on floating rates. Crude oil sales are referenced to the U.S. dollar, thus the Canadian price realized is directly impacted by Canadian and U.S. dollar exchange rates.

12. Commitments

Obligations with a fixed term are as follows:

	2008	2009	2010	2011	2012
Lease of office premises	$ 895	$ 828	$ 828	$ 828	$ 552
Processing arrangements	$ 450	$ 360	$ 288	$ 238	$ 159

rockenergy

File No. 82-34785

Management's Discussion and Analysis

ROCK ENERGY INC. ("ROCK" OR THE "COMPANY") is a publicly traded energy company engaged in the exploration for and the development and production of crude oil and natural gas, primarily in Western Canada. Rock's corporate strategy is to grow and develop an oil and natural gas exploration and production company through internal operations and acquisitions.

Rock evaluates its performance based on net income, operating netback, funds from operations and finding and development costs. Funds from operations are a measure used by the Company to analyze operations, performance, leverage and liquidity. Operating netback is a benchmark used in the oil and natural gas industry to measure the contribution of the oil and natural gas operations following the deduction of royalties, transportation costs and operating expenses. Finding and development costs are another benchmark used in the oil and natural gas industry to measure the capital costs incurred by the Company to find and bring reserves on-stream.

Rock faces competition in the oil and natural gas industry for resources, including technical personnel and third-party services, and capital financing. The Company is addressing these issues through the addition of personnel with the expertise to develop opportunities on existing lands and to control operating and administrative cost structures. Rock also seeks to obtain the best commodity price available based on the quality of its produced commodities.

The following Management's Discussion and Analysis is dated March 12, 2008 and is management's assessment of Rock's historical, financial and operating results, together with future prospects, and should be read in conjunction with the audited consolidated financial statements of Rock for the 12 months ended December 31, 2007.

Basis of Presentation

Financial measures referred to in this discussion, such as funds from operations and funds from operations per share, are not prescribed by generally accepted accounting principles (GAAP). Funds from operations is a key measure that demonstrates the ability to generate cash to fund expenditures. Funds from operations is calculated by taking the cash provided by operations from the consolidated statement of cash flows and adding back changes in non-cash working capital. Funds from operations per share is calculated using the same share basis which is used in the determination of net income per share. These non-GAAP financial measures may not be comparable to similar measures presented by other companies. These financial measures are not intended to represent operating profits for the period nor should they be viewed as an alternative to cash provided by operating activities, net income or other measures of financial performance calculated in accordance with GAAP.

All barrels of oil equivalent (boe) conversions in this report are derived by converting natural gas to oil at the ratio of six thousand cubic feet (mcf) of natural gas to one barrel (bbl) of oil. Certain financial values are presented on a boe basis and such measurements may not be consistent with those used by other companies. Boe may be misleading, particularly if used in isolation. A boe conversion ratio of six mcf to one boe is based on an energy equivalency conversion method primarily applicable at the burner tip and does not necessarily represent a value equivalency at the wellhead.

Certain statements and information contained in this document, including but not limited to management's assessment of Rock's plans and future operations, production, reserves, revenue, commodity prices, operating and administrative expenditures, future income taxes, wells drilled, acquisitions and dispositions, funds from operations, capital expenditure programs and debt levels, contain forward-looking statements. All statements other than statements of historical fact may be forward-looking statements. These statements, by their nature, are subject to numerous risks and uncertainties, some of which are beyond Rock's control, including the effect of general economic conditions, industry conditions, regulatory and taxation regimes, volatility of commodity prices, currency fluctuations, the availability of services, imprecision of reserve estimates, geological, technical, drilling and processing problems, environmental risks, weather, the lack of availability of qualified personnel or management, stock market volatility, the ability to access sufficient capital from internal and external sources and competition from other industry participants for, among other things, capital, services, acquisitions of reserves, undeveloped lands and skilled personnel, any of which may cause actual results or events to differ materially from those anticipated in such forward-looking statements. Such forward-looking statements, although considered reasonable by management at the time of preparation, may prove to be incorrect and actual results may differ materially from those anticipated in the statements made and, therefore, should not unduly be relied on. These statements speak only as of the date of this document. Rock does not intend and does not assume any obligation to update these forward-looking statements, whether as a result of new information, future events or otherwise, except as required by applicable law.

All financial amounts are in thousands of Canadian dollars unless otherwise noted.

GUIDANCE AND OUTLOOK

The Company issued guidance on November 12, 2007 for projected 2007 and 2008 results. The table below provides the guidance for 2007 with actual results.

2007 Guidance

	2007 Guidance	Actual	Difference
2007 Production *(boe/d)*			
Annual	2,150-2,250	2,198	0%
Exit (December average)	2,600-2,800	2,617	(3)%
2006 Funds from Operations			
Annual	$15 million	$15.2 million	1%
Annual *(per share)*	$0.71	$0.72	1%
2006 Capital Budget			
Expenditures	$26 million	$25.6 million	(2)%
Gross wells drilled	16	16	0%
Total net debt at year end	$29 million	$29.1 million	0%
Pricing (Fourth Quarter)			
Oil – WTI	US$85.00/bbl	US$90.68/bbl	7%
Natural gas – AECO	$6.25/mcf	$6.15/mcf	(2)%
US/Cdn dollar exchange rate	1.05	1.02	(3)%

Production averages for the year and the exit rate were within the guidance range. Funds flow from operations was slightly above guidance as lower royalties offset higher G&A costs. Capital expenditures and debt levels were also at guidance levels.

Guidance for 2008 has been updated to reflect results from the winter drilling program and higher expected commodity prices. The table below updates the Company's previous guidance that was issued November 12, 2007.

	2008 Previous Guidance	2008 Revised Guidance	Change
2008 Production *(boe'd)*			
Annual	3,200-3,400	3,400-3,600	6%
Exit	3,700-3,900	3,900-4,100	5%
2008 Funds from Operations			
Annual	$22 million	$28 million	27%
Annual – *(per share)*	$0.86	$1.08	26%
2008 Capital Budget			
Expenditures	$24 million	$30 million	25%
Gross wells drilled	18-22	18-22	0%
Total net debt at year-end	$31 million	$31 million	0%
Pricing (Annual)			
Oil – WTI	US$75.00/bbl	US$85.00/bbl	13%
Natural gas – AECO	Cdn$6.75/mcf	Cdn$7.25/mcf	7%
US/Cdn dollar exchange rate	1.00	1.00	0%

Rock anticipates production from the Saxon winter program to begin by June 2008 versus the previous guidance of October 2008. The Company did not farm out this prospect and retained a 100 percent working interest versus a budgeted 70 percent working interest. As a result, average annual and exit production rates have increased by about 200 boe per day. Capital expenditures have also increased by $6 million to reflect the higher working interest at Saxon and additional infrastructure costs. In the previous guidance the majority of the Saxon infrastructure was to be owned by a third party however, Rock has decided to keep control of this infrastructure. The majority of the increased capital spending is projected to be incurred by June 2008.

Based on the strength of commodity prices to date in 2008, we have increased the reference price of WTI to US$85.00 per barrel and natural gas at AECO to Cdn$7.25 per mcf. Royalty rates are assumed to be approximately 22.5 percent, operating costs per boe have been held at the same rate as previous guidance of $12.20 per boe, G&A costs have decreased to $2.30 per boe based on increased production, and interest costs have been increased reflecting higher average debt levels in the first half of 2008. Funds from operations for 2008 are projected to increase $6 million to $28 million ($1.08 per basic share) based on increased production and commodity prices and other changes noted above.

Rock's bank is reviewing its borrowing base based on the 2007 year-end reserve report. We expect an increase in the loan facility to $38 million from $36 million and to put in place a $6 million development facility which will allow us to finance the increased capital expenditures at Saxon. Given the timing of the capital expenditures and on-stream production date for Saxon, the Company's debt-to-funds flow ratio (based on annualized quarterly funds from operations) is projected to rise to 1.9:1 in the first quarter of 2008 but then fall throughout the year to 1:1 by year-end. The Company will continue to monitor its funds from operations, capital program and debt levels and make adjustments to ensure the projected debt-to-cash flow ratio does not exceed 1.5:1 by year-end.

PRODUCTION and PRICES

Production by Product

	12 Months Ended 12/31/07	12 Months Ended 12/31/06	Change	3 Months Ended 12/31/07	3 Months Ended 12/31/06	Change
Natural gas *(mcf/d)*	**4,261**	6,421	**(34)%**	6,372	3,528	81%
Oil *(bbls/d)*	**215**	179	**20%**	206	206	0%
Heavy oil *(bbls/d)*	**1,194**	792	**51%**	1,323	1,168	13%
NGL *(bbls/d)*	**79**	57	**39%**	81	42	93%
Total (boe/d) *(6:1)*	**2,198**	2,098	**5%**	2,672	2,004	33%

Production by Area

	12 Months Ended 12/31/07	12 Months Ended 12/31/06	Change	3 Months Ended 12/31/07	3 Months Ended 12/31/06	Change
West Central Alberta *(boe/d)*	**642**	972	**(34)%**	1,041	652	60%
Plains *(boe/d)*	**1,196**	795	**50%**	1,325	1,171	13%
Other *(boe/d)*	**360**	331	**9%**	306	181	69%
Total (boe/d) *(6:1)*	**2,198**	2,098	**5%**	2,672	2,004	33%

Production increased 5 percent for the year ended December 31, 2007 over the prior year as the increase in heavy oil production more than offset the reduction in natural gas production. Heavy oil production increases were driven by drilling activity in 2007 and the latter half of 2006. Heavy oil production was negatively affected by natural gas migration issues at Edam in the second half of 2007 as natural gas appears to have permeated the oil zone. We are in the process of remediating the issue and hope to produce the natural gas from the oil zone by concurrently producing it with the oil starting in the second quarter of 2008.

Dispositions in July 2006 of approximately 820 boe per day reduced the natural gas production base for most of 2007 which was partially offset by the Greenbank acquisition that closed at the end of the third quarter in 2007. The Greenbank properties added approximately 500 boe per day of predominately natural gas production. The majority of the drilling in the West Central core area is directed at natural gas and the successful wells were not brought on-stream until the first quarter of 2008. Rock's current production is approximately 2,900 boe per day.

Production increased by 33 percent in the fourth quarter of 2007 from the same period last year as the Greenbank acquisition added production in the quarter while the property dispositions in July 2006 reduced production in the prior-year period. Post-2007 break-up drilling activities increased heavy oil production despite the loss of production from the natural gas migration issues at Edam. As a result of these activities the Company's natural gas weighting has increased from 29 percent in the fourth quarter of 2006 to 40 percent in the fourth quarter of 2007.

Product Prices

	12 Months Ended 12/31/07	12 Months Ended 12/31/06	Change	3 Months Ended 12/31/07	3 Months Ended 12/31/06	Quarterly Change
Realized Product Prices						
Natural gas *($/mcf)*	**6.96**	7.07	(2)%	6.64	7.45	(11)%
Oil *($/bbl)*	**70.69**	64.46	10%	81.66	57.77	41%
Heavy oil *($/bbl)*	**41.18**	38.35	7%	42.56	34.86	22%
NGL *($/bbl)*	**60.00**	61.35	(2)%	67.81	65.47	4%
Combined average ($/boe) *(6:1)*	**44.93**	43.27	4%	45.26	40.73	11%

	12 Months Ended 12/31/07	12 Months Ended 12/31/06	Change	3 Months Ended 12/31/07	3 Months Ended 12/31/06	Quarterly Change
Average Reference Prices						
Natural gas – Henry Hub Daily Spot *(US$/mmbtu)*	**6.98**	6.75	3%	7.01	6.69	5%
Natural gas – AECO C Daily Spot *($/mcf)*	**6.45**	6.54	(2)%	6.15	6.99	(12)%
Oil – WTI Cushing, Oklahoma *(US$/bbl)*	**72.31**	66.22	9%	90.68	60.21	51%
Oil – Edmonton Light *($/bbl)*	**76.35**	72.77	5%	86.42	64.49	34%
Heavy oil – Lloydminster blend *($/bbl)*	**51.63**	50.07	3%	55.49	43.84	27%
US/Cdn $ exchange rate	**0.935**	0.882	6%	1.019	0.878	16%

For the year and quarter ended December 31, 2007 the Company experienced higher oil prices and lower natural gas prices compared to the prior year periods. Rock's weighted average price per boe increased from the prior year which was driven by a higher overall oil weighting in the production mix. For the quarter the significant increase in oil pricing more than offset the reduction in natural gas pricing despite the increase in natural gas production in the overall production mix.

Heavy oil prices were stronger in both periods in 2007 compared to 2006 as WTI prices increased – more so in the fourth quarter of 2007. However, differentials widened in the fourth quarter of 2007 due to temporary pipeline issues, refinery turnarounds, higher condensate prices for blend and a stronger Canadian dollar. Oil prices have continued to remain strong in the first quarter of 2008 and the differential has narrowed and condensate prices have improved from fourth quarter 2007 levels. As a result Rock has been receiving more than $55 per barrel at the wellhead for heavy oil thus far in 2008.

Canadian natural gas prices for the year and fourth quarter of 2007 were below 2006 levels as the stronger Canadian dollar more than offset the modest increase in U.S. natural gas prices for these periods. Natural gas prices have improved in the first quarter of 2008 - currently over $8.00 per mcf - as colder weather has been experienced in North America and strong European and Asian pricing has reduced LNG shipments to North America. Reduced drilling activity in Canada should help support natural gas prices as supply is expected to decline. Natural gas prices traditionally decrease in the summer months as overall demand is reduced. Summer natural gas prices will be influenced by the amount of storage that needs to be replenished for the winter season, cooling demand and the amount of LNG that is imported into North America due to price differentials and demand in the European and Asian markets. The general lack of storage facilities in those markets could also impact the amount of LNG shipped to North America.

REVENUE

The vast majority of the Company's revenue is derived from oil and natural gas operations. Other income is primarily royalty interest revenue.

Oil and Natural Gas Revenue

	12 Months Ended 12/31/07	12 Months Ended 12/31/06	Change	3 Months Ended 12/31/07	3 Months Ended 12/31/06	Quarterly Change
Natural gas	$ 10,830	$ 16,560	(35)%	$ 3,890	$ 2,408	61%
Oil	5,538	4,195	31%	1,547	1,073	39%
Heavy oil	17,951	11,124	62%	5,180	3,790	38%
NGL	1,724	1,277	36%	507	264	100%
	36,042	33,156	9%	11,124	7,535	48%
Other revenue	$ 79	$ 198	(60)%	$12	$ 42	(71)%

Oil and natural gas revenue increased by 9 percent for the year ended December 31, 2007 over 2006 due to higher production levels, particularly heavy oil, which more than offset lower natural gas production. For the fourth quarter of 2007 oil and natural gas revenue increased by 48 percent from the same period in 2006 as higher production, particularly natural gas, and higher oil prices more than offset the decrease in natural gas prices.

ROYALTIES

	12 Months Ended 12/31/07	12 Months Ended 12/31/06	Change	3 Months Ended 12/31/07	3 Months Ended 12/31/06	Quarterly Change
Royalties	$7,035	$6,881	2%	$2,017	$1,452	39%
As a percentage of oil and natural gas revenue	19.5%	20.8%	(6)%	18.1%	19.3%	(6)%
Per boe *(6:1)*	$8.77	$8.98	(2)%	$8.21	$7.88	4%

Royalties increased for the year and quarter ended December 31, 2007 over the prior year periods due to higher production levels. The fourth quarter of 2007 included Alberta Royalty Tax Credits (ARTC) of $459. Although the ARTC program was cancelled effective January 1, 2007, the Alberta Government passed legislation late in 2007 allowing companies with off-calendar (non-December 31) tax year-ends to benefit from a full calendar year of ARTC. Without the ARTC benefit the royalty rates for 2007 would have been 22.2 percent for the quarter and 20.8 percent for the year. The Company is forecasting a royalty rate of approximately 22.5 percent for 2008.

OPERATING EXPENSES

	12 Months Ended 12/31/07	12 Months Ended 12/31/06	Change	3 Months Ended 12/31/07	3 Months Ended 12/31/06	Quarterly Change
Operating expense	$ 9,505	$ 8,947	6%	$ 2,889	$ 2,429	19%
Transportation costs	420	308	36%	130	83	57%
	9,925	9,255	7%	3,019	2,512	20%
Per boe *(6:1)*	$12.37	$12.08	2%	$12.28	$13.63	(10)%

Operating costs for the year and quarter ended December 31, 2007 have increased over 2006 primarily due to higher production. Operating expenses per boe were up slightly for the year ended 2007 compared to 2006 but down about 10 percent in the fourth quarter of 2007 versus the same period in 2006. Lower cost properties from the Greenbank acquisition benefitted fourth quarter 2007 results, while the fourth quarter of 2006 included prior period processing costs. Transportation costs have increased as a result of the acquired properties.

Heavy oil unit costs in 2007 decreased slightly year-over-year to $12.90 from $13.02 per boe and quarter-over-quarter to $13.61 from $14.33 per boe. Costs in the last half of 2007 trended up due to remediation efforts at Edam and 2006 costs were high due to the start-up costs as the result of significant heavy oil drilling that occurred in that year. Total Company operating expenses, including transportation expense, are forecast to be approximately $12.20 per boe in 2008.

GENERAL and ADMINSTRATIVE (G&A) EXPENSE

	12 Months Ended 12/31/07	12 Months Ended 12/31/06	Change	3 Months Ended 12/31/07	3 Months Ended 12/31/06	Quarterly Change
Gross	**$ 4,791**	$ 3,905	23%	$ 1,593	$ 1,085	47%
Per boe *(6:1)*	**5.97**	5.10	17%	6.48	5.89	10%
Capitalized and overhead recoveries	**2,052**	1,627	26%	638	395	62%
Per boe *(6:1)*	**2.56**	2.12	21%	2.60	2.14	21%
Net	**2,739**	2,278	20%	955	690	38%
Per boe *(6:1)*	**3.41**	2.97	15%	3.88	3.74	4%

G&A expense increased on an absolute and per boe basis in 2007 over 2006 due to a higher overall cost environment and in particular the fourth quarter of 2007 also includes $300 of one-time costs associated with management changes and transition costs related to the Greenbank acquisition. Rock capitalizes certain G&A expenses based on personnel involved in the exploration and development initiatives, including salaries and related overhead costs. Gross G&A expenses are expected to be flat on an absolute on an absolute basis in 2008 but decrease on a per boe basis as production is expected to increase.

INTEREST EXPENSE

	12 Months Ended 12/31/07	12 Months Ended 12/31/06	Change	3 Months Ended 12/31/07	3 Months Ended 12/31/06	Quarterly Change
Interest expense (recovery)	**$ 1,157**	$ 924	25%	$ 417	$ 141	195%
Per boe *(6:1)*	**$1.44**	$1.21	20%	$1.70	$0.76	121%

Interest expense has increased for the year and fourth quarter of 2007 over the 2006 periods due to higher average bank debt as capital expenditures, excluding acquisitions, exceeded funds from operations and were funded through the Company's bank facility. Interest expense is expected to increase again in 2008 due to higher average bank debt and increase approximately 20 percent on a per boe basis.

DEPLETION, DEPRECIATION, and ACCRETION (DD&A)

	12 Months Ended 12/31/07	12 Months Ended 12/31/06	Change	3 Months Ended 12/31/07	3 Months Ended 12/31/06	Quarterly Change
D&D expense	**$ 13,989**	$ 13,989	0%	$ 5,021	$ 2,707	85%
Per boe *(6:1)*	**$17.44**	$18.27	(5)%	$20.42	$14.69	39%
Accretion expense	**$ 154**	$ 129	20%	$ 48	$ 34	41%
Per boe *(6:1)*	**$0.19**	$0.17	14%	$0.20	$0.18	11%

Depletion and depreciation expense for the year ended December 31, 2007 equalled the prior year despite higher production and increased for the fourth quarter of 2007 from the 2006 period due to higher production and an increase in the per boe expense. The fourth quarter 2007 per boe depletion and depreciation expense increased as a result of negative reserve revisions recorded at Edam for the natural gas migration issue; reserves in the Greenbank acquisition which were at a higher cost than the existing base and increased capital activities in the West Central core area, which has relatively higher costs than the Plains core area.

The Company's asset retirement obligation (ARO) represents the present value of estimated future costs to be incurred to abandon and reclaim the Company's wells and facilities. The discount rate used is 8 percent.

Accretion represents the change in the time value of ARO. The underlying ARO may be increased over a period based on new obligations incurred from drilling wells, constructing facilities or acquiring operations. Similarly, this obligation can also be reduced as a result of abandonment work undertaken and reducing future obligations. During the year ended December 31, 2007 capital programs and acquisitions increased the underlying ARO by $1,592 (December 31, 2006 – $413) and actual expenditures on abandonments were nil (December 31, 2006 – $104).

INCOME TAX

The Company pays Saskatchewan resource capital taxes based on its production in the province. Rock does not have current income tax payable and does not expect to pay current income taxes in 2008 as the Company and its subsidiaries have estimated resource and other pools available at December 31, 2007 (after the allocation of deferred partnership income) of approximately $106.1 million as set out below:

CEE	$ 42.0 million
CDE	$ 28.5 million
COGPE	$ 4.7 million
UCC	$ 14.9 million
Loss carry-forwards	$ 14.5 million
Other	$ 1.5 million
Total	$ 106.1 million

FUNDS FROM OPERATIONS and NET INCOME/(LOSS)

	12 Months Ended 12/31/07	12 Months Ended 12/31/06	Change	3 Months Ended 12/31/07	3 Months Ended 12/31/06	Quarterly Change
Funds from operations	**$15,189**	$13,867	10%	$4,735	$2,644	79%
Per boe *(6:1)*	**$18.93**	$18.11	5%	$19.26	$14.35	34%
Per share:						
Basic	**$0.72**	$ 0.71	1%	$0.18	$ 0.13	38%
Diluted	**$0.72**	$ 0.71	1%	$0.18	$ 0.13	38%
Net income (loss)	**$561**	($884)	165%	$290	($119)	344%
Per boe *(6:1)*	**$0.70**	($1.15)	161%	$1.18	($0.65)	279%
Per share:						
Basic	**$0.03**	($0.05)	160%	$0.01	($0.01)	200%
Diluted	**$0.03**	($0.05)	160%	$0.01	($0.01)	200%
Weighted average shares outstanding:						
Basic	**21,239**	19,637	8%	25,847	19,637	32%
Diluted	**21,239**	19,655	8%	25,847	19,637	32%

The Company issued 6.1million shares at September 28, 2007 to acquire Greenbank and issued 0.1 million flow-through shares at November 1, 2007 to new management appointments. The Company did not issue any shares in 2006.

Funds from operations for the year ended December 31, 2007 increased by 10 percent over 2006 as the increase in production and realized prices more than offset the increase in royalties, operating, G&A and interest costs. On a per-boe basis, 2007 funds from operations increased by 5 percent from 2006 primarily for the same reasons except for the reduction in royalties. For the fourth quarter of 2007 funds from operations increased by 79 percent on an absolute basis and 34 percent on a per boe basis from the prior year's periods primarily as the increase in production and prices more than offset the increase in royalties, G&A and interest costs. On a per share basis, funds from operations was essentially flat in 2007 versus 2006 but increased 38 percent in the fourth quarter of 2007 over the same quarter in 2006. The Company generated net income for the year and quarter ended December 31, 2007 versus net losses in the prior year periods primarily as a result of booking future income tax recovery in 2007, compared to an expense in 2006, and as a result of the reduction in the future tax rate and the tax pools associated with the Greenbank acquisition. As a result net income per share also increased over the prior year periods.

CAPITAL EXPENDITURES

($000)	12 Months Ended 12/31/07	12 Months Ended 12/31/06	Change	3 Months Ended 12/31/07	3 Months Ended 12/31/06	Quarterly Change
Land	**$ 3,723**	$ 4,822	(23)%	$ 457	$ 120	280%
Seismic	**1,359**	1,081	26%	56	127	(56)%
Drilling and completions	**16,689**	25,130	(34)%	5,567	5,758	(3)%
Capitalized G&A	**2,004**	1,627	23%	589	395	49%
Natural gas gathering systems	**694**	247	181%	665	–	n/a
Total operations	**$ 24,469**	$ 32,907	(26)%	$ 7,334	$ 6,400	15%
Property acquisitions (dispositions) [(1)]	**28,127**	(30,874)	191%	Nil	Nil	n/a
Well site facilities inventory	**94**	(165)	157%	(19)	(206)	(91)%
Office equipment	**1,012**	136	644%	173	39	342%
Total (net of acquisitions and dispositions)	**$ 53,702**	$ 2,004	2,580%	$ 7,488	$ 6,233	20%

(1) Property acquisition for 2007 have been restated from the third quarter report to be presented as the amount allocated to property plant and equipment versus the consideration paid.

Capital expenditures for operations decreased for the year ended December 31, 2007 compared to 2006 as Rock drilled 16 (12.2 net) wells in 2007 versus 33 (28.3 net) wells in 2006. While the number of wells decreased the average cost per well increased as the Company participated in relatively more West Central core area operations than Plains core area operations in 2007. West Central core area targets tend to be deeper multi-zone natural gas targets which are more expensive than shallower heavy oil drilling that occurs in the Plains core area. Natural gas gathering expenditures also increased as tie-in operations were commenced in the Musreau and Kakwa areas and the resulting production came on-stream in the first quarter of 2008.

Land expenditures decreased as the Company focused more on drilling prospects that have been generated in the West Central core area. Seismic expenditures increased as additional seismic was acquired over the Elmworth area. Total net capital expenditures were increased to $54 million in 2007 from $2 million in 2006 as the Company completed the Greenbank acquisition in 2007 and divested properties in 2006.

During 2007, Rock drilled 11 (10.9 net) operated wells and five (1.3 net) non-operated wells, achieving a 91 percent success rate, compared to 27 (27.0 net) operated wells and six (1.3 net) non-operated wells and a 96 percent success rate in 2006. In the Plains core area Rock drilled 8 (8.0 net) heavy oil wells, one (0.9 net) natural gas well and one (1.0 net) dry hole. All of the wells were operated and all successful wells were on-production at year-end. The natural gas well was drilled at Edam and is part of the remediation efforts to remove natural gas from the oil zone. Plains core area production remained relatively flat in 2007 despite limited drilling and production problems at Edam.

In the West Central Alberta core area Rock drilled five (2.2 net) natural gas wells and one (0.1 net) dry hole. Of the five natural gas wells drilled two (0.7 net) were at Kakwa, one (0.2 net) at Musreau, one (0.3 net) at Elmworth and one (1.0 net) at Saxon. The three wells at Kakwa and Musreau were tied-in in the first quarter of 2008 and the Elmworth and Saxon wells are expected to be tied-in the second quarter of 2008. Since year end one (1.0 net) additional natural gas well has been drilled at Saxon. The two Saxon wells and the Elmworth well are expected to add more than 800 boe per day of production once they are on stream.

LIQUIDITY AND CAPITAL RESOURCES

At the end of the third quarter of 2007, Rock completed the acquisition of Greenbank Energy by issuing 3.1 million shares and 3.0 million shares in a private placement to fund the cash portion of the transaction. Capital expenditures, excluding acquisitions, of $25.6 million in 2007 were primarily funded through cash from operations of $14.2 million and bank debt.

Rock's current approved capital budget for 2008 projects spending of $30 million. In 2008 funds from operations are expected to be approximately $28 million. The capital spending in excess of cash flow is intended to be funded through bank debt. Approximately half of the capital budget is expected to be spent in the first four months of the year as the Saxon infrastructure is put in place which should allow the associated production to be on-stream by June. The timing of expenditures will likely cause the Company to temporarily exceed its borrowing base and we expect the bank will provide a $6 million development facility to finance the capital requirements associated with the Saxon infrastructure. At year-end 2007 Rock had debt of $29.1 million against bank lines of $36 million. The bank is currently reviewing the borrowing base and we expect an increase in operating line to $38 million. The Company's debt-to-funds from operations ratio was 1.9:1 at year-end based on annual 2007 results; however this ratio includes all the debt from the Greenbank acquisition but only one quarter of the funds from operations. Based on annualized fourth quarter cash flow, the debt-to-funds from operations ratio was 1.5:1. With the current capital investemnt occurring in the West Central core area, Rock expects the debt-to-funds from operations ratio to increase to 1.9:1 in the first quarter of 2008 and then be reduced as production is brought on stream ending the year at 1.0:1.

The Company has a demand operating loan facility with a Canadian chartered bank. The facility is subject to the bank's valuation of the Company's oil and natural gas assets and the credit currently available is $36 million. The facility bears interest at the bank's prime rate or at the prevailing bankers' acceptance rate plus an applicable bank fee, which varies depending on the Company's debt-to-funds from operations ratio. The facility also bears a standby charge for undrawn amounts. The facility is secured by a first ranking floating charge on all real property of the Company, its subsidiary and partnership and a general security agreement. The next interim review for the facility is scheduled to be completed by April 30, 2008. As at March 11, 2008 approximately $30.1 million was drawn under the facility.

SELECTED ANNUAL DATA

The following table provides selected annual information for Rock:

	12 Months Ended 12/31/07	12 Months Ended 12/31/06	12 Months Ended 12/31/05
Production *(boe/d)*	**2,198**	2,098	1,122
Oil and natural gas revenues ($000)	**$ 36,042**	$ 33,156	$ 22,873
Average realized price *($/boe)*	**$ 44.93**	$ 43.27	$ 55.85
Royalties *($/boe)*	**$ 8.77**	$ 8.98	$ 12.28
Operating expense *($/boe)*	**$ 12.37**	$ 12.08	$ 11.59
Operating netback *($/boe)*	**$ 23.79**	$ 22.21	$ 31.98
Net G&A expense ($000)	**$ 2,739**	$ 2,278	$ 1,411
Stock-based compensation ($000)	**$ 928**	$ 1,188	$ 485
Funds from operations ($000)	**$ 15,189**	$ 13,867	$ 11,433
Per share – basic	**$ 0.72**	$ 0.71	$ 0.74
Per share – diluted	**$ 0.72**	$ 0.71	$ 0.74
Net income (loss)	**$561**	($884)	$ 1,510
Per share – basic	**$0.03**	($0.05)	$ 0.10
Per share – diluted	**$0.03**	($0.05)	$ 0.10
	As at 12/31/07	As at 12/31/06	As at 12/31/05
Total assets	**$ 130,495**	$ 85,380	$ 99,603
Total liabilities	**$ 44,301**	$ 24,901	$ 39,385

SELECTED QUARTERLY DATA

The following table provides selected quarterly information for Rock:

	3 Months Ended 12/31/07	3 Months Ended 09/30/07	3 Months Ended 06/30/07	3 Months Ended 03/31/07	3 Months Ended 12/31/06	3 Months Ended 09/30/06	3 Months Ended 06/30/06	3 Months Ended 03/31/06
Production *(boe/d)*	**2,672**	1,965	2,036	2,114	2,004	1,613	2,190	2,594
Oil and natural gas revenues ($000)	**$ 11,126**	$ 8,106	$ 8,279	$ 8,533	$ 7,535	$ 7,023	$ 8,774	$ 9,824
Average realized price *($/boe)*	**$45.26**	$44.85	$44.66	$44.84	$40.73	$47.30	$44.01	$42.08
Royalties *($/boe)*	**$8.21**	$9.18	$9.23	$8.66	$7.88	$5.27	$8.97	$12.26
Operating expense *($/boe)*	**$12.28**	$12.38	$12.10	$12.75	$13.63	$13.13	$10.55	$11.55
Operating netback *($/boe)*	**$24.77**	$23.29	$23.33	$23.43	$19.22	$28.90	$24.49	$18.27
Net G&A expense *($000)*	**$ 955**	$ 528	$ 530	$ 726	$ 690	$ 477	$ 462	$ 649
Stock-based compensation *($000)*	**$ 213**	$ 207	$ 241	$ 267	$ 295	$ 308	$ 305	$ 280
Funds from operations *($000)*	**$ 4,735**	$ 3,397	$ 3,536	$ 3,521	$ 2,644	$ 3,791	$ 4,028	$ 3,404
Per share – basic	**$0.18**	$ 0.17	$ 0.18	$ 0.18	$ 0.13	$ 0.19	$ 0.21	$ 0.17
Per share – diluted	**$0.18**	$ 0.17	$ 0.18	$ 0.18	$ 0.13	$ 0.19	$ 0.21	$ 0.17
Net income (loss) *($000)*	**$290**	$ 15	($117)	$ 373	($119)	$ 891	($583)	($1,074)
Per share – basic	**$0.01**	$ 0.00	($0.01)	$0.02	($0.01)	$ 0.05	($0.03)	($0.05)
Per share – diluted	**$0.01**	$ 0.00	($0.01)	$0.02	($0.01)	$ 0.05	($0.03)	($0.05)
Capital expenditures *($000)*	**$ 7,488**	$ 8,367	$ 2,552	$ 7,184	$ 6,223	$ 12,520	$ 4,397	$ 9,728
	As at 12/31/07	As at 09/30/07	As at 06/30/07	As at 03/31/07	As at 12/31/06	As at 09/30/06	As at 06/30/06	As at 03/31/06
Working capital *($000)*	**($29,072)**	($26,589)	($15,268)	($16,242)	($12,580)	($8,990)	($31,135)	($30,766)

Production was relatively flat over the first three quarters of 2007 as activities were primarily directed at West Central core area projects that are expected to be on-stream in the first half of 2008. Production increased in the fourth quarter of 2007 as a result of the Greenbank acquisition. The operating netback was also relatively stable over the first three quarters of 2007 resulting in a constant level of funds from operations. Improved pricing and lower royalties (due to the ARTC benefit) in the fourth quarter of 2007 increased the operating netback slightly and with higher production, funds from operations improved about 40 percent over the previous quarter.

G&A expenses were higher in the fourth quarter of 2007 due to costs associated with year-end reporting, management changes and Greenbank transition costs. Net capital expenditures were low in the second quarter of 2007 due to spring breakup conditions as the Company did not drill any wells. A significant portion of Rock's West Central core area activities are winter-access only and as a result these operations tend to be concentrated in the December to March timeframe. The Company usually undertakes Plains core area and Elmworth activities in the third quarter of the year. Negative working capital increased significantly in the last half of 2007 as Rock drilled 4 (4.0 net) heavy oil wells in the Plains core area and began operations in the West Central core area, particularly at Kakwa, Musreau, Elmworth and Saxon.

Reserves

Rock's reserves have been independently evaluated by GLJ Petroleum Consultants Ltd. (GLJ) at year-end 2007. This is the fourth year in which GLJ has evaluated the Company's reserves. The reserves as at December 31, 2007 and 2006 have been evaluated in accordance with *National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities (NI 51-101)*. The following tables provide a reconciliation of the Company's reserves between year-end 2006 and year-end 2007 on a gross basis (before deducting royalties and without including any royalty interest) (gross interest).

Rock's gross interest reserves at year-end 2007 are 5.3 million boe of proved reserves and 9.3 million boe of proved plus probable reserves. The growth in gross interest reserves resulted from oil and natural gas operations (net of revisions) which added 0.7 million boe of proved reserves and 0.9 million boe of proved plus probable reserves and the Greenbank acquisition which added 1.0 million of proved reserves and 1.9 million of proved plus probable reserves.

RESERVES RECONCILIATION

The following table is a reconciliation of Rock's gross interest reserves at December 31, 2007 using GLJ's forecast pricing and cost estimates as at December 31, 2007.

Reconciliation of Company Gross Interest Reserves by Principal Product Type (Forecast Prices and Costs)

	Light and Medium Oil		NGL		Heavy Oil		Natural Gas		Total Oil Equivalent	
Factors	Proved (mbbl)	Proved Plus Probable (mbbl)	Proved (mbbl)	Proved Plus Probable (mbbl)	Proved (mbbl)	Proved Plus Probable (mbbl)	Proved (mmcf)	Proved Plus Probable (mmcf)	Proved (mboe)	Proved Plus Probable (mboe)
December 31, 2006	413	588	119	183	2,705	4,299	7,507	13,591	4,488	7,334
Additions[1]	0	0	72	113	378	532	2,986	5,167	949	1,506
Technical revisions[2]	7	(3)	(3)	(9)	(359)	(617)	472	73	(278)	(617)
Acquisitions	45	69	45	98	0	0	5,289	10,383	971	1,898
Dispositions	0	0	0	0	0	0	0	0	0	0
Production	(81)	(81)	(26)	(26)	(450)	(450)	(1,536)	(1,536)	(812)	(812)
December 31, 2007	383	572	207	360	2,275	3,764	14,717	27,677	5,318	9,309

[1]Additions include discoveries, extensions, infill drilling and improved recovery.
[2]Technical revisions include technical revisions and economic factors.
Note: Figures may not add due to rounding; mbbl=1,000 bbl, mmcf=1,000 mcf, mboe = 1,000 boe.

RESERVES AND NET PRESENT VALUE (FORECAST PRICES AND COSTS)

The following tables summarize Rock's remaining gross interest reserves volumes along with the value of future net revenue utilizing GLJ's forecast pricing and cost estimates as at December 31, 2007.

Reserves

Reserves Category	Light and Medium Oil (mbbl)	NGL (mbbl)	Heavy Oil (mbbl)	Natural Gas (mmcf)	Total Oil Equivalent (mboe)
Proved					
Proved producing	323	99	1,919	7,230	3,545
Proved non-producing	60	91	124	5,440	1,183
Proved undeveloped	0	17	232	2,047	590
Total proved	383	207	2,275	14,717	5,318
Probable additional	189	152	1,489	12,960	3,991
Total proved plus probable	572	360	3,764	27,677	9,309

Note: Figures may not add due to rounding; mbbl=1,000 bbl, mmcf=1,000 mcf, mboe = 1,000 boe..

Net Present Value of Future Net Revenue

($000)	Before Income Taxes Discounted at (% per year)					After Income Taxes Discounted at (% per year)				
Reserves Category	0	5	10	15	20	0	5	10	15	20
Proved										
Proved producing	95,480	82,548	73,339	66,361	60,844	95,480	82,548	73,339	66,361	60,844
Proved non-producing	29,247	24,258	20,840	18,304	16,333	24,015	20,477	17,923	15,998	14,469
Proved undeveloped	6,439	4,508	3,106	2,058	1,254	4,623	2,948	1,754	875	211
Total proved	131,166	111,314	97,285	86,722	78,431	124,118	105,943	93,016	83,234	75,524
Probable additional	94,553	70,100	55,135	45,009	37,702	69,250	51,177	39,998	32,469	27,063
Total proved plus probable	225,719	181,414	152,420	131,731	116,133	193,639	157,121	133,014	115,703	102,587

Note: Figures may not add due to rounding.

PRICING ASSUMPTIONS

The following benchmark prices, inflation rates and exchange rates were used by GLJ for the forecast prices and costs evaluation.

Summary of Pricing and Cost Rate Assumptions at December 31, 2007 – Forecast Prices and Costs

	Oil				NGL				Natural Gas		
Year	WTI Cushing (US$/bbl)	Edmonton Reference Price ($/bbl)	Cromer Medium 29° API ($/bbl)	Hardisty Heavy 12° API ($/bbl)	Edmonton Propane ($/bbl)	Edmonton Butane ($/bbl)	Edmonton Pentane ($/bbl)	Ethane ($/bbl)	AECO-C ($/mcf)	US$/Cdn$ Exchange Rate	Cost Inflation Rate (%/year)
2008	92.00	91.10	79.26	54.02	58.30	72.88	92.92	22.73	6.75	1.00	2
2009	88.00	87.10	75.78	51.61	55.74	69.68	88.84	25.49	7.55	1.00	2
2010	84.00	83.10	72.30	49.19	53.18	66.48	84.76	25.66	7.60	1.00	2
2011	82.00	81.10	70.56	47.98	51.90	64.88	82.72	25.66	7.60	1.00	2
2012	82.00	81.10	70.56	47.98	51.90	64.88	82.72	25.66	7.60	1.00	2
2013	82.00	81.10	70.56	49.04	51.90	64.88	82.72	25.66	7.60	1.00	2
2014	82.00	81.10	70.56	50.09	51.90	64.88	82.72	26.35	7.80	1.00	2
2015	82.00	81.10	70.56	51.15	51.90	64.88	82.72	26.94	7.97	1.00	2
2016	82.02	81.12	70.57	52.21	51.91	64.89	82.74	27.52	8.14	1.00	2
2017	83.66	82.76	72.00	53.29	52.97	66.21	84.42	28.11	8.31	1.00	2
2018	85.33	84.42	73.44	54.36	54.03	68.20	86.11	28.67	8.48	1.00	2
2019+	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	1.00	2

FINDING, DEVELOPMENT AND ACQUISITION COSTS

The following table summarizes Rock's finding, development and acquisition costs for the years ended December 31, 2007, 2006 and 2005, including future development costs.

	12 months ended Dec. 31, 2007	12 months ended Dec. 31, 2006	12 months ended Dec. 31, 2005	3 Year Cumulative Total
Oil and Natural Gas Operations:				
Proved finding and development costs				
Capital expenditures[1] *($000)*	**$24,163**	$32,907	$22,912	$79,982
Change in future capital costs *($000)*	**3,501**	2,939	962	7,402
Total capital *($000)*	**$27,664**	$35,846	$23,874	$87,384
Reserve additions[2] *(mboe)*	**949**	2,181	1,188	4,318
Proved finding and development costs *($/boe)*	**$29.15**	$16.44	$20.10	$20.24
Proved plus probable finding and development costs				
Capital expenditures[1] *($000)*	**$24,163**	$32,907	$22,912	$79,982
Change in future capital costs *($000)*	**3,930**	7,986	$3,900	$15,816
Total capital *($000)*	**$28,093**	$40,893	$26,812	$95,798
Reserve additions[2] *(mboe)*	**1,506**	3,624	2,201	7,331
Proved plus probable finding and development costs *($/boe)*	**$18.66**	$11.28	$12.18	$13.07
Acquisitions/Dispositions:				
Proved finding and development costs – acquisitions (dispositions)				
Capital expenditures[1] *($000)*	**$28,524**	($30,878)	$60,853	$58,499
Change in future capital costs *($000)*	**4,136**	(2,400)	3,647	5,383
Total capital *($000)*	**$32,660**	($33,278)	$64,500	$63,882
Reserve additions *(mboe)*	**971**	(1,042)	2,397	2,326
Proved finding and development costs *($/boe)*	**$33.64**	($31.94)	$26.91	$27.46

Proved plus probable finding and development costs – acquisitions (dispositions)				
Capital expenditures[1] *($000)*	**$28,524**	($30,878)	$60,853	$58,499
Change in future capital costs *($000)*	**11,417**	(2,400)	3,733	12,750
Total capital *($000)*	**$39,941**	($33,278)	$64,586	$71,249
Reserve additions *(mboe)*	**1,898**	(1,406)	3,154	3,646
Proved plus probable finding and development costs *($/boe)*	**$21.05**	($23.67)	$20.48	$19.54
Total Activities:				
Proved finding and development costs				
Capital expenditures[1] *($000)*	**$52,687**	$2,029	$83,765	$138,481
Change in future capital costs *($000)*	**7,637**	539	4,609	12,785
Total capital *($000)*	**$60,324**	$2,568	$88,374	$151,266
Reserve additions[3] *(mboe)*	**1,643**	1,279	3,620	6,542
Total proved finding and development costs *($/boe)*	**$36.72**	$2.01	$24.41	$23.12
Proved plus probable finding and development costs				
Capital expenditures[1] *($000)*	**$52,687**	$2,029	$83,765	$138,481
Change in future capital costs *($000)*	**15,347**	5,586	7,633	28,566
Total capital *($000)*	**$68,034**	$7,615	$91,398	$167,047
Reserve additions[3] *(mboe)*	**2,786**	2,153	5,284	10,223
Total Proved plus probable finding and development costs *($/boe)*	**$24.42**	$3.54	$17.30	$16.34

(1) Capital expenditures include capitalized G&A which has been allocated between oil and natural gas operations and acquisitions, and exclude purchases of equipment still held in inventory and administrative capital expenditures.

(2) Reserve additions exclude revisions.

(3) Reserve additions include revisions.

(4) The aggregate of the exploration and development costs incurred in the most recent financial year and the change during that year in estimated future development costs generally will not reflect total finding and development costs related to reserve additions for that year.

Finding, development and acquisition ("FD&A") costs are broken down according to oil and natural gas operations, acquisitions and dispositions, and total activities. Oil and natural gas operations include all capital activities in which the Company participated, including operations on the acquired properties after their respective closing dates, but exclude reserve revisions. FD&A costs on the acquired properties are based on the reserve evaluation as at each respective year end less new reserves from operations post closing and were increased by the amount of production from the closing date to December 31 of the respective year to provide an estimate of the reserves purchased. FD&A costs on the disposed properties are based on the reserve evaluation as at December 31, 2005 and were decreased by the amount of production to the closing date. FD&A costs for total activities include operations, acquisitions, dispositions and reserve revisions.

Finding and development costs on operations increased in 2007 compared to 2006 and 2005 as Rock spent more capital in the higher cost West Central core area versus the relatively less expensive Plains core area in order to test the Company's exploration prospects, particularly Saxon and Kakwa. While the operations were successful these projects did not come on stream in 2007 and as a result reserve bookings, in management's view, are conservative given the lack of production history. In addition a significant amount of land, seismic and infrastructure costs (including future capital) are incurred for these projects. Future drilling locations should benefit from these expenditures. Rock completed the Greenbank acquisition at the end of the third quarter of 2007 and the reserve report contains a significant amount of future capital given the down spacing opportunities that exist on this land base. The FD&A calculations in the table above do not exclude any amounts for undeveloped land, valued at $5 million at the time of closing. Overall FD&A costs are high for 2007 and include significant technical revisions in our heavy oil properties particularly at Edam where the Company experienced the natural gas migration issue. Remediation efforts are currently underway to remove the natural gas from the oil zones and further restore production. If successful, management would expect to see a positive reserve revision in the future. On a three year basis the FD&A costs are in our view more reflective of the progress made in growing the Company and generate recycle ratios (FD&A divided by operating netback) of 1.9:1 for operations and 1.5:1 overall.

LAND HOLDINGS

The following table summarizes Rock's land holdings as at December 31, 2007 and 2006:

(acres)		Dec. 31, 2007	Dec. 31, 2006	Change
Developed	– Gross	**87,882**	63,085	39%
	– Net	**32,406**	23,566	38%
Undeveloped	– Gross	**135,069**	76,030	78%
	– Net	**61,718**	39,429	57%
Total	– Gross	**222,951**	139,115	60%
	– Net	**94,123**	62,995	49%

NET ASSET VALUE

The following table summarizes Rock's net asset value and net asset value per share as at December 31, 2007 and December 31, 2006:

($000 except number of shares and net asset value per share)	December 31, 2007	December 31, 2006	Change
Proved plus probable reserves[(1)(2)]	**152,420**	105,688	44%
Undeveloped land[(3)]	**13,380**	8,220	63%
Working capital including debt	**(29,094)**	(12,580)	132%
Net asset value (Basic)	**136,706**	101,328	35%
Basic shares *(000)*	**25,878**	19,637	32%
Net asset value per share (basic)	**$5.28**	$5.16	2%
Option proceeds	**7,893**	7,405	7%
Net asset value (Diluted)	**144,599**	108,733	33%
Diluted shares *(000)*	**28,185**	21,405	32%
Net asset value per share (diluted)	**$5.13**	$5.08	1%

(1) Proved plus probable reserves value is based on the net present value of future net revenue from gross reserves using GLJ Petroleum Consultants Ltd.'s January 2007 and 2006 forecast pricing and costs estimates and using a discount rate at 10 percent.

(2) Reserve values are based on the existing Alberta royalty regime.

(3) Undeveloped land value is based on the actual cost of land purchased at land sales; land acquired from ELM Optimum Qwest in the second quarter of 2005 has been valued at $100 per acre and land acquired through the Greenbank acquisition in the third quarter of 2007 has been valued at $200 per acre.

Reserve values in the above table are based on the existing Alberta royalty regime. GLJ Petroleum Consultants Ltd. prepared high and low sensitivity cases under the proposed Alberta royalty regime based on assumptions that all independent consulting firms agreed to use in their evaluations. The low royalty sensitivity case assumes that a heavy oil par price is used in the royalty calculations, solution natural gas royalties are calculated using the same rate and price basis as non-associated natural gas, and the deep natural gas royalty adjustment is applied to all existing and future wells. The high royalty sensitivity case assumes that a light oil par price is used in the royalty calculations for heavy oil, solution natural gas royalties are calculated using the same rate and price basis as non-associated natural gas but restricted to no less than the current royalty rate of 30 percent on solution natural gas, and the deep natural gas royalty adjustment is applied only to wells drilled after 2008.

The following table summarizes Rock's proved and probable reserve values, net asset value and net asset value per share as at December 31, 2007 under the different royalty assumptions:

($000 except number of shares and net asset value per share)	**December 31, 2007 Existing Royalty**	December 31, 2007 Low Royalty	December 31, 2007 High Royalty
Proved plus probable reserves[1]	**152,420**	152,420	144,747
Net asset value (Basic)	**136,706**	136,706	129,033
Basic shares *(000)*	**25,878**	25,878	25,878
Net asset value per share (basic)	**$5.28**	$5.28	$4.99
Net asset value (Diluted)	**144,599**	144,599	136,926
Diluted shares *(000)*	**28,185**	28,185	28,185
Net asset value per share (diluted)	**$5.13**	$5.13	$4.86

[1] Proved plus probable reserves value is based on the net present value of future net revenue from gross reserves using GLJ Petroleum Consultants Ltd.'s January 2007 forecast pricing and costs estimates and using a discount rate at 10 percent.

CONTRACTUAL OBLIGATIONS

In the course of its business, the Company enters into various contractual obligations including the following:

- royalty agreements;
- processing agreements;
- right-of-way agreements; and
- lease obligations for office premises.

Obligations with a fixed term are as follows:

	2008	2009	2010	2011	2012
Office premise leases	$ 895	$ 828	$ 828	$ 828	$ 552
Processing agreements	450	360	288	238	159
Demand bank loan[1]	$27,405				

[1] The demand bank loan is currently under its annual review and is expected to remain in place.

OUTSTANDING SHARE DATA

At December 31, 2007 and to date, Rock had 25,877,642 common shares outstanding. At December 31, 2007 the Company had 2,307,822 stock options outstanding with an average exercise price of $3.42 per share. As of the date hereof Rock has 2,145,363 options outstanding.

OFF-BALANCE-SHEET ARRANGEMENTS

Rock does not have any special-purpose entities nor is it party to any arrangement that would be excluded from the balance sheet.

RELATED-PARTY TRANSACTIONS

The Company has not entered into any related-party transactions during the reporting period.

DISCLOSURE CONTROLS AND PROCEDURES

The Company has a corporate disclosure policy that is distributed to and made available to staff through the corporate computer network. The policy is reviewed by the Chief Executive Officer, Chief Financial Officer and the Board of Directors annually. Procedures were developed and put in place in support of the disclosure policy. The Chief Executive Officer and the Chief Financial Officer have evaluated the effectiveness of the disclosure controls and procedures as at December 31, 2007 and, based on that evaluation; believe them to be effective given the size and nature of the Company's operations. All control systems by their nature have inherent limitations and, therefore, Rock's disclosure controls and procedures are believed to provide reasonable, but not absolute, assurance that:

• the communications by the Company with the public are timely, factual and accurate and broadly disseminated in accordance with all applicable legal and regulatory requirements;

• non-publicly disclosed information remains confidential; and

• trading of the Company's securities by directors, officers and employees remains in compliance with applicable securities laws.

INTERNAL CONTROLS OVER FINANCIAL REPORTING

The Chief Executive Officer and the Chief Financial Officer have supervised the design of internal controls over financial reporting and these controls were in place as at December 31, 2007. The Company acquired Greenbank at the end of the third quarter of 2007 and assimilated the accounts into Rock's existing accounts and as a result there was no material change to the design of internal controls over financial reporting. In addition the Company did not make any other material change to internal controls in 2007. The Chief Executive Officer and the Chief Financial Officer believe the internal controls, including compensating controls to overcome the lack of certain segregation of duties, are designed appropriately given the nature and size of the Company's operations, and that a material deficiency in design does not exist. Because of their inherent limitations, internal controls over financial reporting may not prevent or detect misstatements, errors or fraud. Control systems, no matter how well conceived or operated, can provide only reasonable, not absolute assurance that the objectives of the control systems are met.

CHANGE IN ACCOUNTING POLICIES

As of January 1, 2007 the Company adopted new policies to implement the pronouncements from the Canadian Institute of Chartered Accountants in respect of financial instruments - presentation and disclosures, hedging and other comprehensive income. The new standards require certain financial instruments to be recognized on the balance sheet at their fair value. The application of these policies did not result in changes to amounts reported in the consolidated financial statements for the period ended December 31, 2007.

NEW ACCOUNTING PRONOUNCEMENTS

Capital Disclosures

The Canadian Institute of Chartered Accountants (CICA) issued CICA Handbook section 1535, Capital Disclosures. The section is effective for fiscal years beginning on or after October 1, 2007. It requires disclosure on objectives, policies and processes for managing capital.

Rock will adopt this section effective January 1, 2008.

Financial Instruments – Disclosures and Presentation

The Canadian Institute of Chartered Accountants (CICA) issued CICA Handbook section 3862, Financial Instruments - Disclosures and section 3863, Financial Instruments - Presentation which replace section 3861, Financial Instruments – Disclosures and Presentation. These sections are effective for fiscal years beginning on or after October 1, 2007. Section 3863 does not change the presentation requirements of the previous section 3861 however, section

3862 places new increased emphasis on the nature and extent of risks arising from financial instruments and how they are managed. Rock will adopt this section effective January 1, 2008.

International Financial Reporting Standards

The Canadian Institute of Chartered Accountants proposed to implement International Financial Reporting Standards ("IFRS") as part of Canadian GAAP. The adoption of IFRS in Canada will result in significant changes to current Canadian GAAP and to financial reporting practices followed by Rock. IFRS accounting standards are scheduled to be implemented for years beginning after December 31, 2010. Rock will be required to adopt the standard for the year beginning January 1, 2011. Currently, the application of IFRS in Canada and particularly to the oil and natural gas industry requires further clarification and as a result the effect of IFRS adoption on the Company's accounting policies and reporting standards and practices is not presently determinable.

CRITICAL ACCOUNTING ESTIMATES

A summary of the Company's significant accounting policies is contained in note 2 to the audited consolidated financial statements. These accounting policies are subject to estimates and key judgements about future events, many of which are beyond Rock's control. The following is a discussion of the accounting estimates that are critical to the financial statements.

Oil and Natural Gas Accounting – Reserves Recognition – Rock retained independent petroleum engineering consultants GLJ Petroleum Consultants Ltd. (GLJ) to evaluate its oil and natural gas reserves, prepare an evaluation report, and report to the Company's Reserves Committee. The process of estimating oil and natural gas reserves is subjective and involves a significant number of decisions and assumptions in evaluating available geological, geophysical, engineering and economic data. These estimates will change over time as additional data from ongoing development and production activities becomes available and as economic conditions affecting oil and natural gas prices and costs change. Reserves can be classified as proved, probable or possible with decreasing levels of certainty to the likelihood that the reserves will be ultimately produced.

Oil and Natural Gas Accounting – Full Cost Accounting – Under the full cost method of accounting for exploration and development activities, all costs associated with these activities are capitalized. The aggregate net capitalized costs and estimated future abandonment costs, less estimated salvage values, are amortized using the unit-of-production method based on estimated proved oil and natural gas reserves, resulting in a depletion expense. The depletion expense is most affected by the estimate of proved reserves and the cost of unproved properties. Unproved costs are reviewed quarterly to determine if proved reserves have been established, at which point the associated costs are included in the depletion calculation. Changes to any of these estimates may affect Rock's earnings.

Under the full cost method of accounting, the Company's investment in oil and natural gas assets is evaluated at least annually to consider whether the investment is recoverable and the carrying amount does not exceed the value of the properties, a process known as the "ceiling test". The carrying value of oil and natural gas properties and production equipment is compared to the sum of undiscounted cash flows expected to result from Rock's proved reserves. If the carrying value is not fully recoverable, the amount of impairment is measured by comparing the carrying value of property and equipment to the estimated net present value of future cash flows from proved plus probable reserves using a risk-free interest rate. Any excess carrying value above the net present value of the future cash flows is recorded s a permanent impairment. Reserve, revenue, royalty and operating cost estimates and the timing of future cash flows are all critical components of the ceiling test. Revisions of these estimates could result in a write-down of the carrying amount of oil and natural gas properties.

Asset Retirement Obligations – The Company recognizes the estimated fair value of an asset retirement obligation (ARO) in the period in which it is incurred as a liability, and records a corresponding increase in the carrying value of the related asset. The future asset retirement obligation is an estimate based on the Company's ownership interest in wells and facilities and reflects estimated costs to complete the abandonment and reclamation as well as the estimated timing of the costs to be incurred in future periods. Estimates of the costs associated with abandonment and reclamation activities require judgement concerning the method, timing and extent of future retirement activities. The capitalized amount is depleted on a unit-of-production method over the life of the proved reserves. The liability amount is increased each reporting period due to the passage of time and this accretion amount is charged to earnings in the period. Actual costs incurred on settlement of the ARO are charged against the ARO. Judgements affecting current and annual expense are subject to future revisions based on changes in technology, abandonment timing, costs, discount rates and the regulatory environment.

Stock-based Compensation – Stock options issued to employees and directors under the Company's stock option plan are accounted for using the fair value method of accounting for stock-based compensation. The fair value of the option is recognized as stock-based compensation expense and contributed surplus over the vesting period of the option. Stock-based compensation expense is determined on the date of an option grant using the Black-Scholes option pricing model. The Black-Scholes pricing model requires the estimation of several variables including estimated volatility of Rock's stock price over the life of the option, estimated option forfeitures, estimated life of the option, estimated risk-free rate and estimated dividend rate. A change to these estimates would alter the valuation of the option and would result in a different related stock-based compensation expense.

Goodwill – The Company recognized goodwill in conjunction with the Elm/Optimum/Qwest acquisitions that occurred in the second quarter of 2005. In assessing if goodwill has been impaired the Company assesses the fair value of its assets and liabilities. This assessment takes into consideration such factors as: the estimated fair value of the Company's reserves and unproven properties; the current trading value of the common shares; and recent market transactions for similar types of assets. If the Company's common share trading value was to deteriorate from current levels an impairment to goodwill might exist.

BUSINESS RISKS

Rock is exposed to a number of business risks, some of which are beyond its control, as are all companies in the oil and natural gas exploration and production industry. These risks can be categorized as operational, financial and regulatory.

Operational risks include generating, finding and developing, and acquiring oil and natural gas reserves on an economical basis (including acquiring land rights or gaining access to land rights); reservoir production performance; marketing; production; hiring and retaining employees; and accessing contract services on a cost-effective basis.

Rock attempts to mitigate these risks by employing highly qualified staff and operating in areas where employees have expertise. In addition the Company outsources certain activities to be able to lever industry expertise, without having the burden of hiring full-time staff given the current scope of operations. Typically the Company has outsourced the marketing and certain engineering and land functions. Rock is attempting to acquire oil and natural gas operations; however Rock will be competing against many other companies for such operations, many of which will have greater access to resources. As a small company, gaining access to contract services may be difficult given the competitive nature of the industry, but Rock will attempt to mitigate this risk by utilizing existing relationships.

Financial risks include commodity prices, the Canadian/US dollar exchange rate and interest rates, all of which are largely beyond the Company's control. Currently Rock has not used any financial instruments to mitigate these risks. The Company would consider using these financial instruments depending on the operating environment. The Company also will require access to capital. Currently Rock has a debt facility in place and intends to use its debt capacity in the future in conjunction with capital expenditures including acquisitions. It intends to use prudent levels of debt to fund capital programs based on the expected operating environment. It also intends to access equity markets to fund opportunities; however, the ability to access these markets will be determined by many factors, many of which will be beyond the control of the Company.

Rock is subject to various regulatory risks, principally environmental in nature. The Company has put in place a corporate safety program and a site-specific emergency response program to help manage these risks. The Company hires third-party consultants to help develop and manage these programs and help Rock comply with current environmental legislation. Increased public and political concern regarding climate change issues will likely result in increased regulation regarding emissions standards. Given that the Company produces hydrocarbons, such regulation could cause Rock to alter the way it operates and also result in additional costs and taxes associated with climate change regulation which could have a material effect on the Company.

ADDITIONAL INFORMATION

Further information regarding the Company, including the Company's Annual Information Form, can be accessed under the Company's public filings found on SEDAR at www.sedar.com. Information can also be obtained by contacting the Company at Rock Energy Inc., Suite 800, 607 - 8th Avenue S.W., Calgary, Alberta, T2P 0A7.

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