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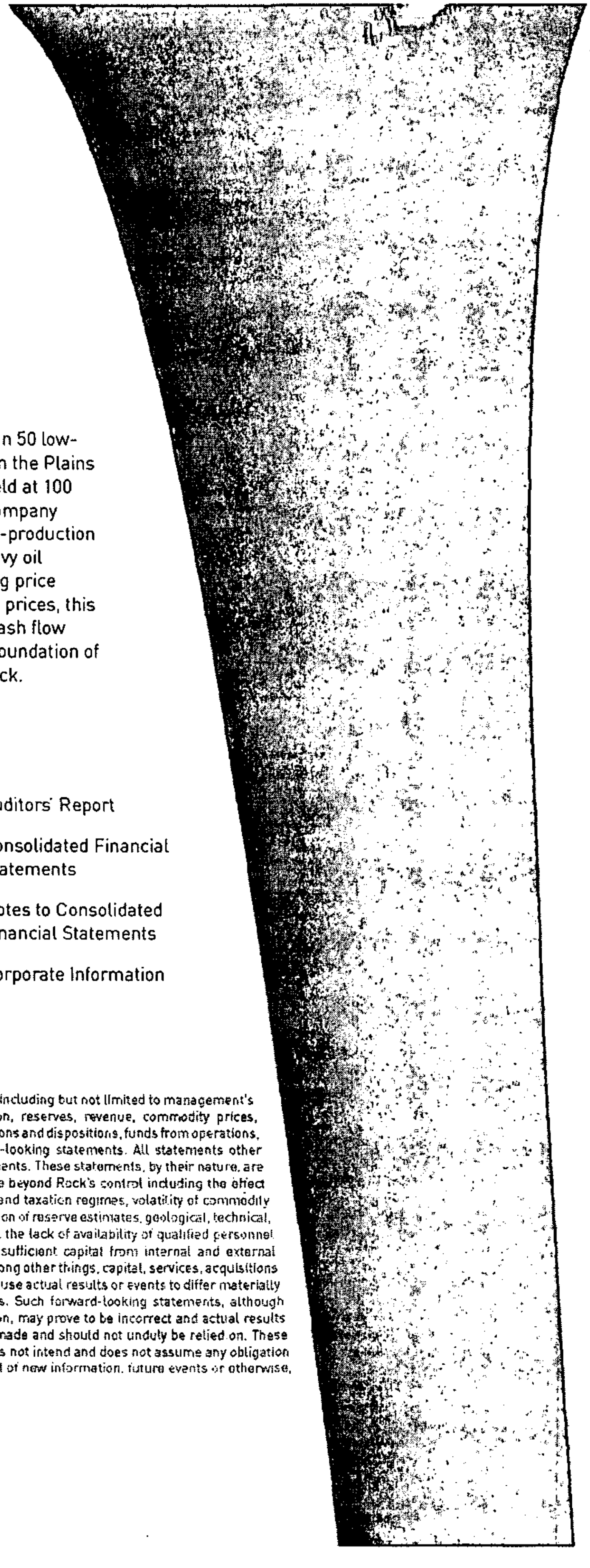
WE HAVE THE RIGHT MIX

rockenergy

2006 ANNUAL REPORT

Heavy OIL



LOW RISK...FOUNDATION

Rock has a portfolio of more than 50 low-risk heavy oil drilling locations in the Plains core area. These projects are held at 100 percent working interest, are Company operated and can be brought on-production quickly. With changes in the heavy oil marketplace providing narrowing price differentials and higher netback prices, this production is generating solid cash flow and rates of return. This is the foundation of production and cash flow for Rock.

CONTENTS

Forward-looking statements

Certain statements and information contained in this document, including but not limited to management's assessment of Rock's future plans and operations, production, reserves, revenue, commodity prices, operating and administrative expenditures, 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 that may cause actual results or events to differ materially from those anticipated in the 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 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.

Natural GAS

HIGHER-RISK...HIGH-REWARD...UPSIDE
More than 25 natural gas drilling locations in the West Central core area will provide significant growth and upside opportunity for Rock. These projects can require up to $6.0 million per well to drill, complete and tie-in, so Rock will look to reduce its interest in some of its 100 percent projects to maintain an appropriate risk profile, while maintaining operatorship. Though these wells are much more expensive, and can take more than one year to drill and bring on-production, they can also provide significant value for our company. w

PROFILE

Rock Energy Inc. is an emerging oil and gas exploration and production company currently producing approximately 2,200 barrels of oil equivalent per day (boe/d) from its oil and gas properties in Western Canada.

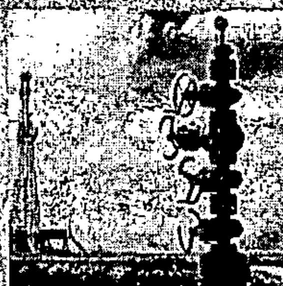
Rock's strengths include a balanced and diversified asset base and a proven management team. Through a combination of grassroots exploration and acquisitions, the Company expects to build value and grow to 10,000 boe per day within the next three to five years.

Rock is listed on the Toronto Stock Exchange under the symbol RE.

ANNUAL GENERAL MEETING

Rock Energy Inc.'s Annual General Meeting of Shareholders will be held at The Western Canadian Place Conference Centre, Plus 30, 801-6th Street S.W., Calgary, Alberta on Tuesday, May 15 at 3:00 pm M.D.T. All shareholders are invited to attend. Those unable to do so are requested to sign and return the form of proxy mailed with this report to ensure representation at the meeting.

FOCUS



- Rationalized our asset base in 2006.
- Sold non-core areas with 820 boe per day of production in July.
- Realized proceeds of $30.9 million, generating 80 percent return on investment.
- Proceeds used to fund future exploration and development in core areas.
- Focused on two core areas: Plains and West Central.
- Balanced portfolio of commodities, risk/reward, and operations.

CONTROL

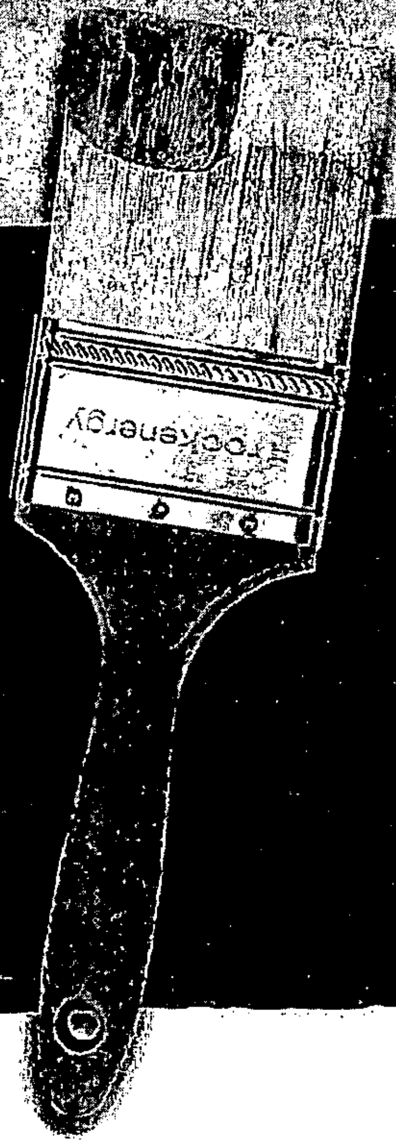
- Increased working interest and operatorship to current levels of:
  Plains 100% W.I.
  West Central 45% W.I.
- Maintain financial discipline at both the operational and balance sheet level.
- Strong and accountable management team and Board of Directors, founded with the skill-sets and technical depth needed to grow beyond 10,000 boe per day.

UPSIDE

- Capital program of 18-20 gross wells in 2007.
- Rock is targeting to deliver 25 percent growth in exit daily production year-over-year.
- Company aims to achieve production volumes of 2,600-2,800 boe per day by year-end.
- Significant exploration plays in the West Central core area:
  - Musreau: Downspacing and commingling of up-hole zones to be tested in 2007;
  - Greater Kaybob: Up to 10 natural gas exploration prospects, four of which are expected to be tested in 2007; and
  - Kakwa: Two exploration wells are planned to be drilled in 2007.

FOUNDATION

- Plains region provides the foundation of oil production and cash flow.
- Large inventory of more than 50 drilling locations on low-risk projects in the Plains area that will generate solid economic results.
- Exploitation projects in Musreau include downspacing and commingling up-hole zones.
- A solid balance sheet, including more than $5 million of excess available debt capacity over 2007 capital requirements.



2006 PERFORMANCE

Corporate Summary

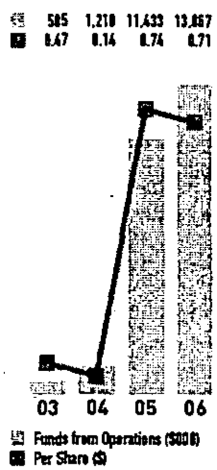
	Twelve months ended December 31, 2006	Twelve months ended December 31, 2005	Twelve months ended December 31, 2004 [2]	**Three months ended December 31, 2006**	Three months ended December 31, 2005	Three months ended December 31, 2004
Financial						
Oil and natural gas revenue ($000)	**$ 33,156**	$ 22,873	$ 2,845	**$ 7,535**	$ 11,760	$ 863
Funds from operations ($000) [1]	**$ 13,867**	$ 11,433	$ 1,218	**$ 2,644**	$ 6,020	$ 404
Per share						
– basic	**$ 0.71**	$ 0.74	$ 0.14	**$ 0.13**	$ 0.31	$ 0.04
– diluted	**$ 0.71**	$ 0.74	$ 0.14	**$ 0.13**	$ 0.31	$ 0.04
Net income (loss) ($000)	**$ (884)**	$ 1,510	$ 571	**$ (119)**	$ 747	$ 183
Per share						
– basic	**$ (0.05)**	$ 0.10	$ 0.06	**$ (0.01)**	$ 0.04	$ 0.02
– diluted	**$ (0.05)**	$ 0.10	$ 0.06	**$ (0.01)**	$ 0.04	$ 0.02
Capital expenditures, net ($000)	**$ 2,004**	$ 84,237	$ 6,252	**$ 6,223**	$ 7,768	$ 3,852

As at December 31	**2006**	2005	2004
Working capital including bank debt ($000)	**$ (12,580)**	$ (24,442)	$ 12,043
Common shares outstanding (000)	**19,637**	19,637	9,259
Options outstanding (000)	**1,767**	1,120	532

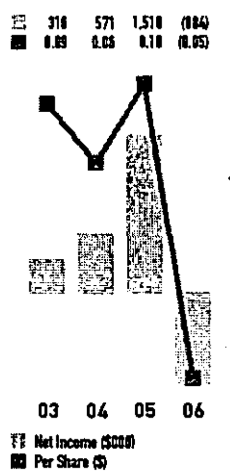
(1) Funds from operations and funds from operations per share are not terms under generally accepted accounting principles (GAAP), and represent cash generated from operating activities before changes in non-cash working capital. Rock considers these are key measures as they demonstrate the Company's 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.

(2) The Company changed its year-end at December 31, 2004 from March 31. In order to make comparisons of periods compatible, information presented for the 12-month period ended December 31, 2004 has been compiled by combining the nine-month period ended December 31, 2004 with the three-month period ended March 31, 2004.

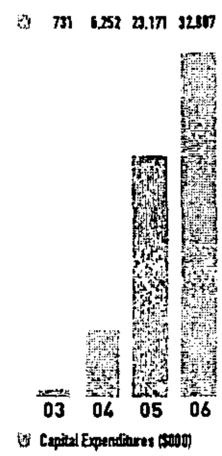
FUNDS FROM OPERATIONS



NET INCOME



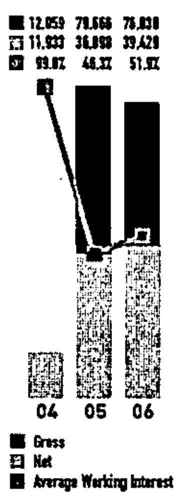
CAPITAL EXPENDITURES ON OPERATIONS



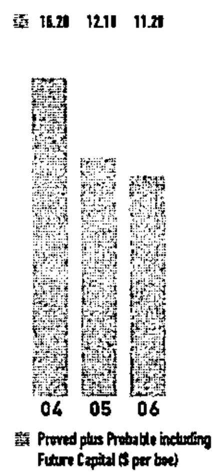
	Twelve months ended December 31, 2006	Twelve months ended December 31, 2005	Twelve months ended December 31, 2004	**Three months ended December 31, 2006**	Three months ended December 31, 2005	Three months ended December 31, 2004
Operations						
Average daily production						
Light crude oil (bbls/d)	**179**	133	77	**206**	207	71
Heavy crude oil (bbls/d)	**792**	187	-	**1,168**	480	-
NGL (bbls/d)	**57**	56	17	**42**	75	19
Natural gas (mcf/d)	**6,421**	4,476	520	**3,528**	8,147	665
Total (boe/d)	**2,098**	1,122	181	**2,004**	2,120	201
Average product prices						
Light crude oil (Cdn$/bbl)	**$ 64.46**	$ 64.95	$ 46.42	**$ 57.77**	$ 63.63	$ 55.90
Heavy crude oil (Cdn$/bbl)	**$ 38.35**	$ 27.44	-	**$ 34.86**	$ 24.81	-
NGL (Cdn$/bbl)	**$ 61.35**	$ 56.19	$ 41.36	**$ 65.47**	$ 58.80	$ 45.09
Natural gas (Cdn$/mcf)	**$ 7.07**	$ 10.22	$ 6.72	**$ 7.45**	$ 12.06	$ 6.77
BOE (Cdn$/boe)	**$ 43.27**	$ 55.85	$ 43.02	**$ 40.73**	$ 60.29	$ 46.68
Operating netback (Cdn$/boe)	**$ 22.21**	$ 31.98	$ 25.16	**$ 19.22**	$ 34.79	$ 34.27
Wells drilled (gross (net))						
Heavy oil wells	**25 (25.0)**	15 (15)	4 (4.0)	**8 (8.0)**	3 (3.0)	4 (4.0)
Light oil wells	**2 (0.7)**	4 (1.7)	-	-	1 (0.1)	-
Gas wells	**4 (1.4)**	9 (1.3)	2 (2.0)	-	5 (0.7)	2 (2.0)
Dry and abandoned wells	**2 (1.1)**	5 (0.5)	3 (3.0)	**1 (0.1)**	-	1 (1.0)
Total wells	**33 (28.2)**	33 (22.4)	9 (9.0)	**9 (8.1)**	9 (3.8)	7 (7.0)
Success rate (net)	**96%**	82%	67%	**99%**	100%	86%

WELLS DRILLED

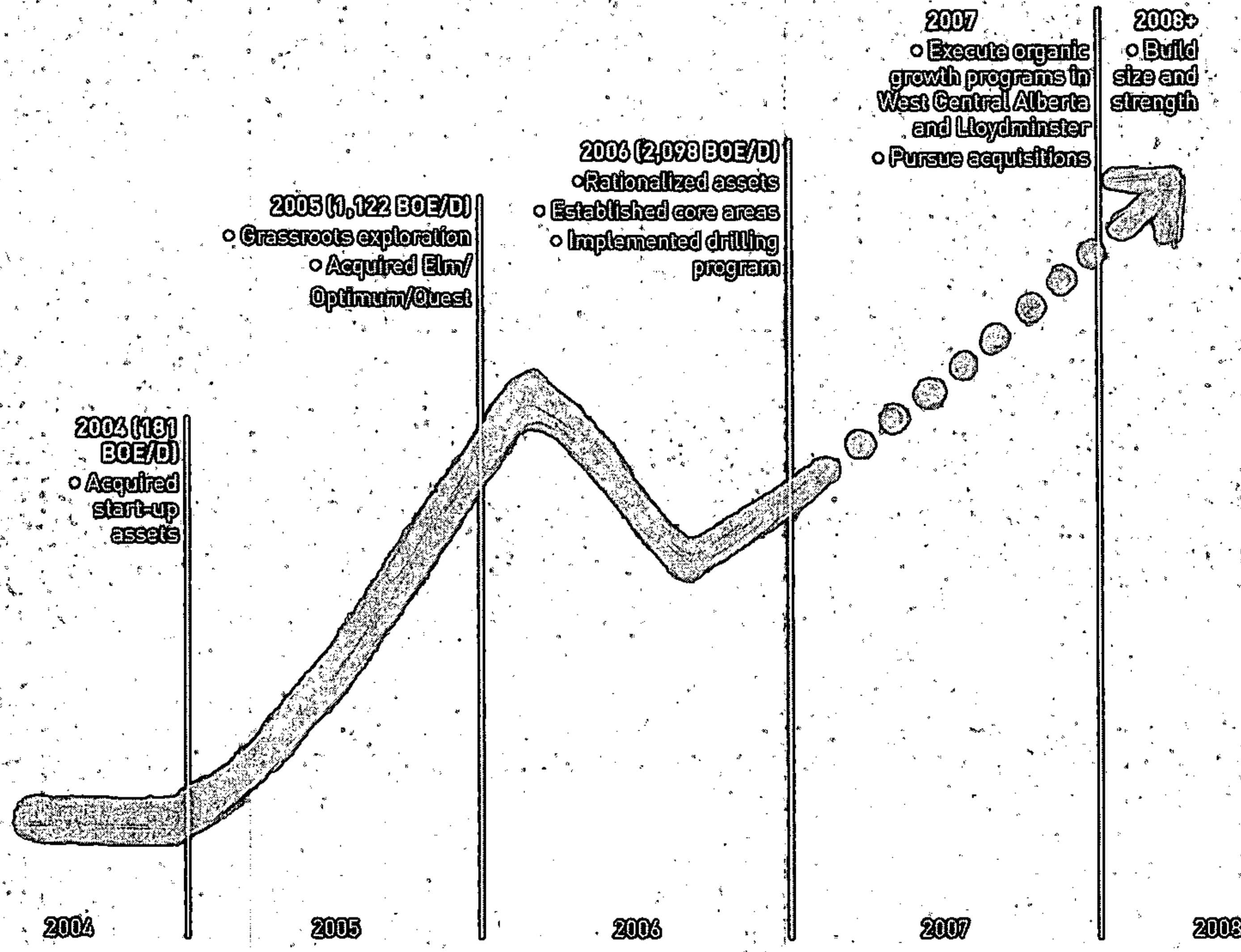
UNDEVELOPED LAND

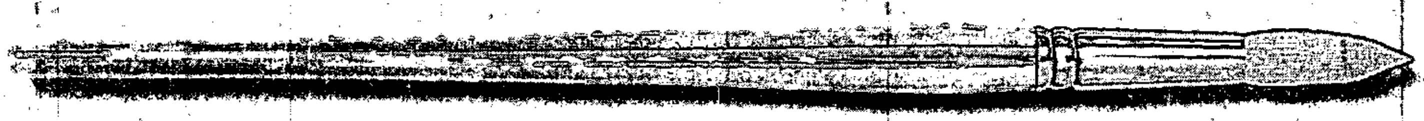


OIL AND NATURAL GAS OPERATIONS FINDING AND DEVELOPMENT COSTS

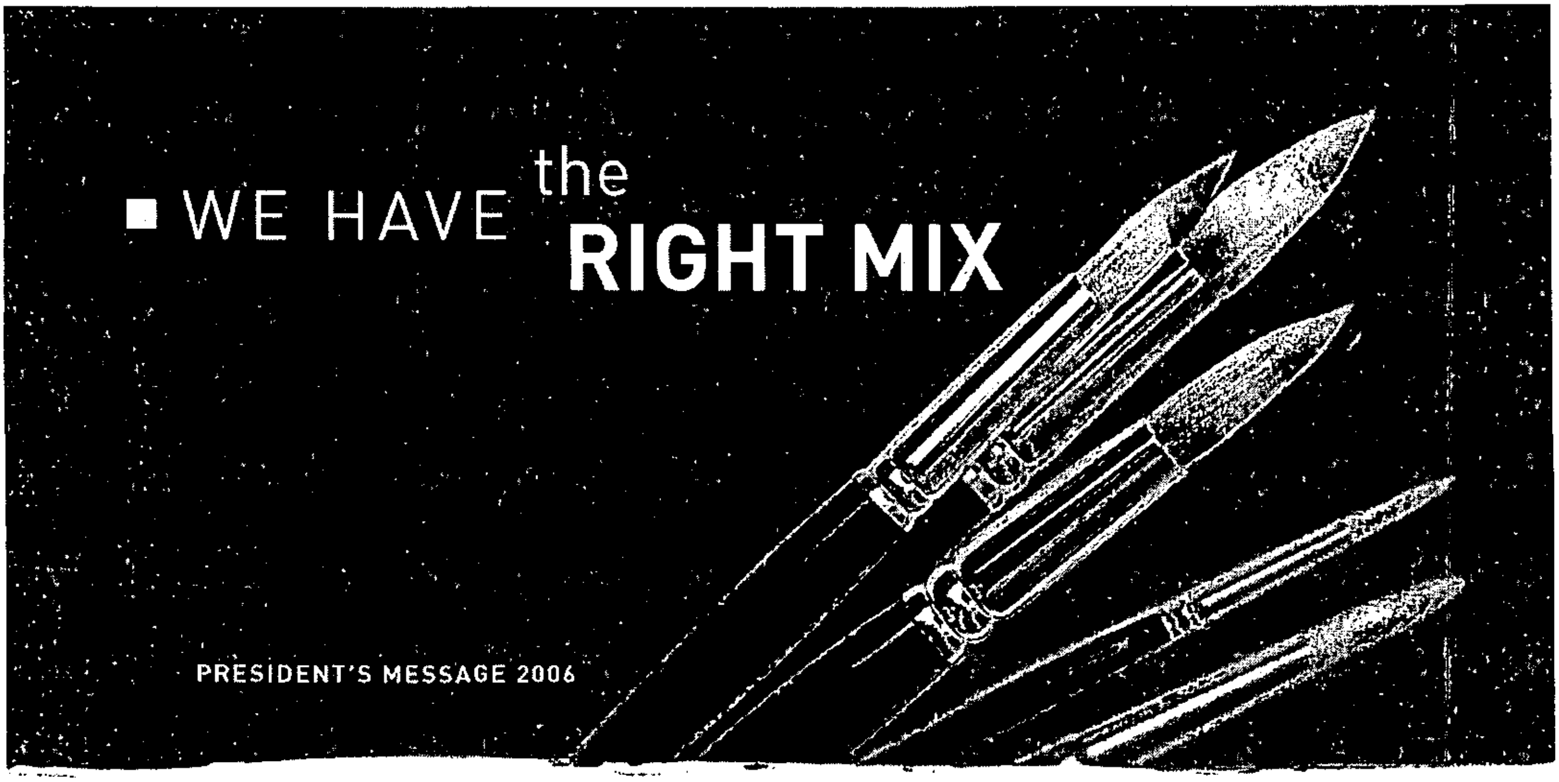


A PLAN





AND THE ABILITY TO EXECUTE IT



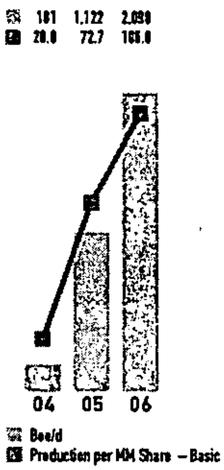
WE HAVE the RIGHT MIX

PRESIDENT'S MESSAGE 2006

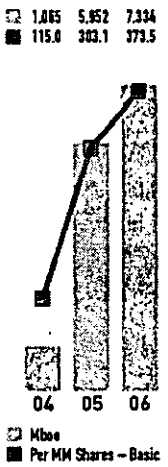
The past year was one of transformation for Rock Energy. This time last year we were managing an asset base that was largely non-operated and was spread across the entire Western Canada Sedimentary Basin. Today, we are focused into two core areas, generating growth with our drilling program, and positioned to pursue acquisitions.

NET ASSET VALUE PER SHARE

AVERAGE DAILY PRODUCTION



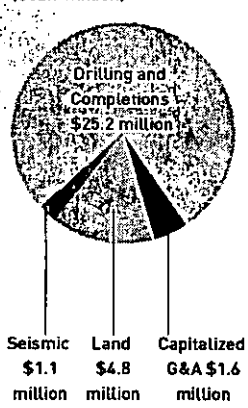
PROVED PLUS PROBABLE RESERVES



THE ROCK ENERGY TEAM

Pictured from left to right: (back row) Peter Scott, Simonne Birrell, Scott Wilhelm, Lesley McGilp, Tony Geier, Anita Gross, Sean Moore, Michelle Coleman, Scott Reimond; (front row) Scott Myers, Allen Bey, Lisa Elliott, Arezki Ioughlissen, Sandy Brown, Sarah Coleman, Jantina Rintoul, Priscilla Brown, James Elliott and Lisa Elliott.

2006 CAPITAL EXPENDITURES ON OPERATIONS
($32.7 million)



The assets we acquired in 2005 provided our company with a diverse portfolio of opportunities. We evaluated the portfolio and determined the best areas, with the right mix, for building a strong, viable company. Rock engaged in a rationalization program in the first half of 2006 that reduced our production base to 1,400 boe per day by July. We emerged with two core areas that gave us increased focus, higher working interests and increased operatorship. The specific steps we took were:

- Initiated and concluded an asset rationalization program;
- Consolidated our asset base into two core areas and increased our average working interest and operatorship;
- Strengthened our balance sheet through the sale process in July;
- Demonstrated the capability of our technical team by drilling 33 (28.2 net) wells with a 96 percent success rate, resulting in 25 (25.0 net) heavy oil wells, two (0.7 net) light oil wells, four (1.4 net) gas wells and two (1.1 net) dry and abandoned wells;
- Re-completed nine (6.1 net) wells resulting in four (4.0 net) oil wells, three (1.4 net) gas wells, and two (0.7) abandoned wells;
- Added 3.6 million boe of proved plus probable reserves with a finding and development cost of $11.28 per boe and generated a recycle ratio of 1.6;

- Increased our production rate from 1,400 boe per day, following the disposition in July, to more than 2,200 boe per day in March 2007. Our 2006 average production was 2,097 boe per day (an 87 percent increase from 2005). The increase was generated through the drill bit and does not include a further 300 boe per day of natural gas scheduled to come on-stream in November 2007 at Musreau in West Central Alberta, when the area's natural gas plant is expanded;
- Generated funds from operations of $13.9 million ($0.71 per share) for the year, a 21 percent increase over the prior year despite lower product prices;
- Increased our net asset value per share by 42 percent to $5.34 per basic share ($5.25 per diluted share); and
- Built a strong inventory of prospects, totalling more than 80 drilling locations, to drive our future growth.

Our 2006 plan was to rationalize Rock's asset base and initiate our grassroots exploration program. We did what we set out to do. We have restored Rock's production level and reserve base, focused into two core areas and accumulated a large inventory of drilling locations.

Though we originally intended to sell only a net 200-300 boe per day while engaging in a swap of producing assets, it became evident during the process that our drilling inventory was superior to the assets being offered for swap. In addition, the offers for our assets were above our value estimates and provided an 80 percent rate of return on our investment. We had acquired the assets for $20.6 million, had generated $6.2 million in cash flow after capital costs and were offered $30.9 million to sell them. At that point, we decided to make a larger disposition and to reinvest the extra funds into our drilling program.

It was the right decision. Our drilling program added 3.6 million boe of proved plus probable reserves and increased our total reserve base to 7.3 million boe (proved plus probable) after the sale of properties and production during the year.

Rock has emerged from its year of transformation with the "right mix" of: production (heavy oil, light oil and natural gas); risk and reward; geographic locations and financial capability. The heavy oil component of our opportunity base provides a large inventory, exceeding 50 drilling locations, of low-risk projects that generate solid economic returns, and can be drilled and brought on-stream quickly. In our West Central core area, we have identified 25-30 drilling locations for natural gas. Though these gas targets have longer cycle times to bring on-production, they also possess larger reserve potential and upside. It is the combination of heavy oil and natural gas projects that positions our company to generate growth in production and value.

STRATEGY AND EXECUTION

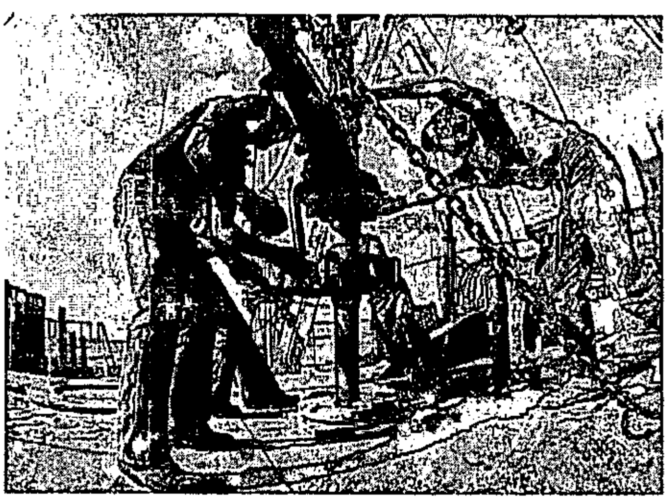
Rock has always proclaimed a strategy of "buy-build-sell". Two-thousand six was a year of building:

- A foundation of assets we think we can grow;
- An inventory of drilling locations; and
- A strong balance sheet and cash flow base.

Two-thousand seven appears to be the year in which we will continue to build on our production base and opportunity inventory through the drill bit, while pursuing complementary acquisitions. The recent changes in regulations regarding the taxation of royalty trusts have altered the landscape for many junior oil and natural gas companies. The new environment should serve Rock well. We believe it will prompt the consolidation of smaller oil and natural gas companies, especially those that may have been banking on an early exit, possibly at lower acquisition metrics due to the energy trusts' increased cost of capital. This should provide Rock with increased opportunities for mergers and acquisitions.

At Rock, our plan was to grow beyond 10,000 boe per day before looking for an event to provide shareholders with the opportunity to monetize their investments. With this in mind, we recruited a team of professionals that had experience in managing this size of operation and level of activity.

As for the ultimate monetization event, we are focused on building a strong base of quality assets, with clearly understandable upside that an intermediate, senior or even an international oil and natural gas company can readily recognize. As we get larger and stronger, our ability to capture opportunities will increase along with the liquidity in our shares. With increased liquidity, our shareholders will also have more options to decide when to monetize the value of their investment. As long as we focus on Rock-solid value creation, our shareholders will be rewarded.



2007 DRILLING PROGRAM

Rock's Board of Directors has approved an initial capital budget of $22 million for 2007 (of which $2.0 million was spent in December 2006). During the remainder of the year, the Company expects to drill approximately 18 (13.6 net) wells and increase production to exit the year at 2,600-2,800 boe per day. This would achieve 20-25 percent growth in exit volumes, before any significant contribution from our exploration projects.

The drilling program will consist of eight to ten heavy oil wells and two natural gas wells in our Plains core area and six to eight natural gas wells in our West Central core area. Two of the West Central core area drills will be high-impact exploration wells at Kakwa and the rest will be lower-risk exploration wells in the Greater Kaybob and Musreau areas.

To date in 2007, Rock has drilled three (3.0 net) heavy oil wells and one (1.0 net) abandoned well in the Plains core area and two natural gas wells in the West Central core area, including one (0.1 net) well at Waskahigan and one (0.3 net) well at Kakwa. The natural gas well at Waskahigan was completed with disappointing results and is currently a standing, cased natural gas well. The well at Kakwa is cased and is being completed with production testing likely to occur following spring break-up.

Assuming average commodity prices of US$65.00 per barrel of W.T.I. crude oil and Cdn$7.50 per mcf of natural gas at AECO, Rock's 2007 capital program is expected to generate cash flow of $15 million ($0.76 per share). The capital program is expected to be funded with our cash flow and debt facility.

MARKET OUTLOOK

During 2006, the W.T.I. crude oil price started at US$65.54 per barrel, rose to exceed US$75.00 per barrel in the summer and then closed the year at US$62.09 per barrel, for an average price of US$66.22 per barrel. For 2007, we believe there is strong evidence to support a price in the range of US$60.00-$70.00 per barrel, especially when considering the tight supply-demand balance, the demonstrated inelasticity of demand to price, the political uncertainty in the Middle East and the economic growth that economies worldwide are demonstrating.

A key value component of the Rock story lies in the heavy to light oil price differential. This is the discount in price that heavy oil receives compared to light crude oil. If the differential is low, Rock receives a higher netback price. During the year, the differential between the W.T.I. and the Lloyd blend price averaged US$21.56 per barrel. The differential began the year at US$25.58 per barrel, narrowed to US$14.34 per barrel during the summer, and closed the year at US$19.27 per barrel. At present, the differential is US$16.50 per barrel. We believe the market fundamentals are in place to maintain (or even further narrow) this level going forward. Given the leverage that heavy oil economics have on price changes, we view these trends as very positive for Rock:

On the natural gas side, unseasonably warm weather in 2005 led to a significant build-up of inventories. These high inventory levels and low demand rates translated into lower natural gas prices. During 2006 the price started at Cdn$8.60 per mcf at AECO, and fell to Cdn$4.72 per mcf in September before recovering to Cdn$7.10 per mcf in December. The 2006 average was Cdn$6.45 per mcf. Nearing the end of the first quarter of 2007, the high natural gas storage levels have been drawn down due to a particularly cold February and reduced drilling rates which are having an impact on available natural gas supply. We expect the natural gas market will come into balance as we enter the next winter season, but prices are likely to remain volatile. Natural gas prices are currently trading at about Cdn$7.25 per at AECO.

Two-thousand seven will be an exciting year for Rock. We have a strong drilling program that is capable of growing our production by 25 percent by year-end, plus an exploration program that could significantly impact Rock for 2008. The industry's structural landscape has changed and that is providing opportunities as well as challenges for our company. We believe we are well-positioned to take advantage of the opportunities, and will continue to work hard to do so.

I extend my thanks and appreciation to all of our employees and directors. It is through their hard work and commitment that we have been able to make such demonstrable progress during a year of transformation.

On behalf of the Board of Directors,

[Signed] "Allen J. Bey"

Allen J. Bey
President and Chief Executive Officer

March 15, 2007

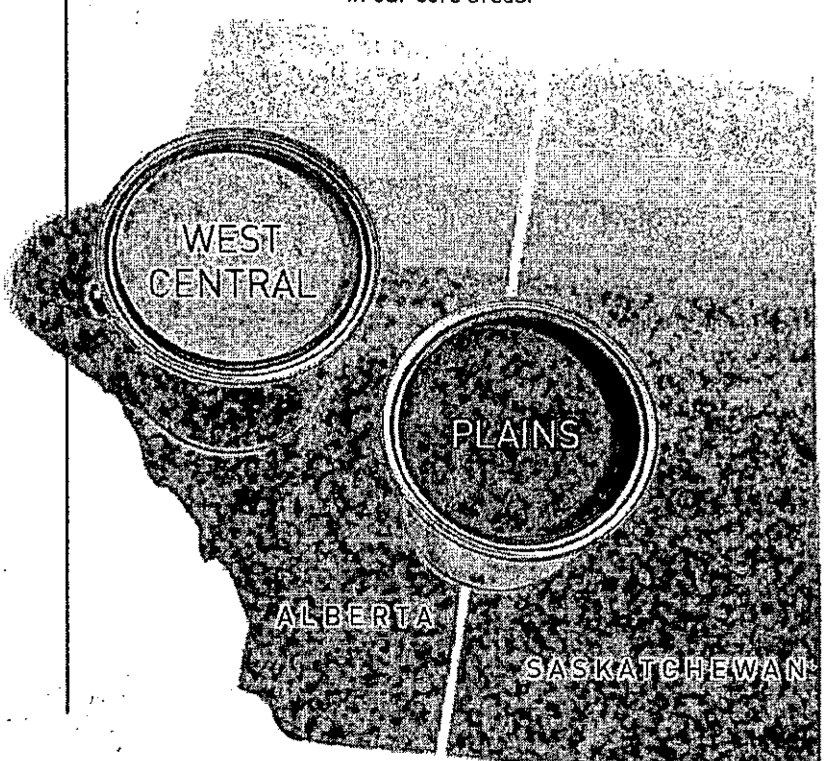
EXPLORATION and PRODUCTION

STRATEGY

1 BUILD A FOUNDATION FROM WHICH TO GROW

2006: Rock established a foundation of production and cash flow with the right mix of commodities, properties, risk and reward. We have two core areas that provide exposure to the lower-risk heavy oil and shallow gas drilling targets, plus the higher-risk but high-impact Deep Basin stacked gas plays.

2007: During the next year we will continue to build our foundation of heavy oil production and begin to develop our gas exploitation projects, which include downspacing and commingling in the Musreau area. We will continue to add to our inventory of drilling locations and land in our core areas.

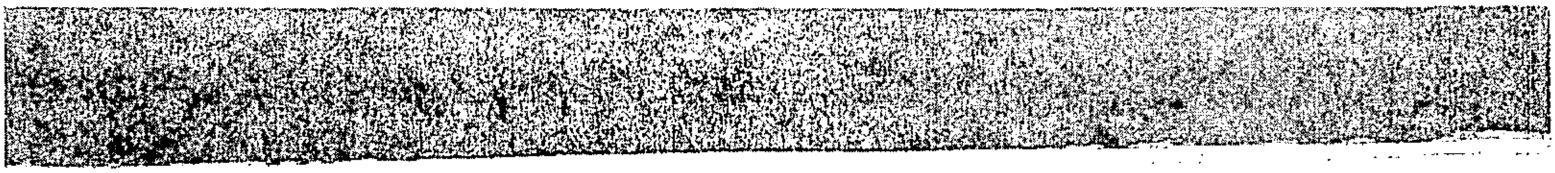


2 IDENTIFY AREAS TO BUILD

2006: The acquisition of Elm/Optimum/Qwest in 2005, provided the Company with a toehold of land and production across the Basin. During the last year Rock completed an asset rationalization project that disposed of properties we believed had no further development potential, and emerged with two core areas: Plains and West Central Alberta.

These are areas where we see significant development, exploitation and exploration potential. We have built upon this with our grassroots exploration program, developing a core asset area with a strong prospect inventory.

2007: As we move forward with drilling in our core areas we will continue to build through land sales, farm-ins, and complementary acquisitions. Though we have identified two core areas currently, we will continue to review opportunities to add a third core area that would be meaningful for the Company.



■ FOCUSED on 2 CORE AREAS

3 LAYER IN COMPLEMENTARY ACQUISITIONS

2006: Rock rationalized the Elm/Optimum/Quest assets which were acquired in 2005. Dispositions from the rationalization program raised $30.9 million, providing Rock with an excellent capital position for acquisitions and internal development. During the year Rock reviewed asset acquisition opportunities that would fit into its core areas. However, the Company's careful due diligence process concluded that acquisition prices were too high in light of prevailing commodity prices and the exploitation/development opportunities in the available assets. Consequently, Rock focused capital spending on our own exploration opportunities instead of acquisitions.

2007: With our core areas clearly defined, our last acquisition rationalized, the financial strength of our company solidified and the recent turn in the oil and gas markets, we believe that 2007 will be an opportune time to pursue acquisitions to provide the next level of growth. In this new operating landscape, size and strength will matter, as they will increase Rock's ability to access acquisition opportunities, increase the Company's liquidity, and bring value to shareholders.

4 BUILD SIZE AND STRENGTH

2006: Following the asset rationalization program, production dropped to 1,400 boe per day. However, our drilling program rebuilt the production level to 2,200 boe per day by year-end. Rock thereby replaced all of the volumes that were sold, and increased our reserve base by another 23 percent. Our net asset value increased by 42 percent by year-end to reach $5.25 per diluted share, and the Company accumulated an inventory of more than 80 locations. We clearly built value during the year.

2007: Our capital budget of $20 million is intended to grow our production base to 2,600-2,800 boe per day by the end of the year. Rock's exploration drilling locations could provide even more significant growth in 2008. In addition to pursuing growth through the drill bit, Rock is pursuing acquisitions to provide the Company with more opportunity, a larger production base, and greater market capitalization. This will improve our ability to take advantage of the emerging structural landscape in the oil and natural gas industry. The Company will continue to focus on value creation as we build size and strength.

PLAINS ALBERTA

CORE AREA

A PORTFOLIO OF LOW-RISK PRODUCTION ADDITIONS

OVERVIEW

In the Plains core area Rock generally holds 100 percent working interest in its lands and production. We operate all of our activities in this core area. The main focus is exploring for heavy oil and shallow gas from the Mannville Group at depths of 500-1,000 metres. In 2006 Rock spent $15 million and drilled 25 (25.0 net) successful wells in the Plains area and one dry hole. This activity increased production from 680 boe per day at the beginning of the year to 1,250 boe per day at year-end. Rock's activity also added 2.6 million boe of proved plus probable reserves at an average cost of $7.10 per boe (including future capital).

One of the more exciting discoveries was at Edam where we proved up a significant pool extension. The drilling results were very exciting, with the best well producing more than 150 boe per day. For 2007 we have identified another three potential oil wells and one gas well at Edam.

In addition to drilling the 26 wells during 2006, our exploration team identified another 50 heavy oil drilling locations. In 2007 Rock plans to spend $5 million on drilling eight to ten wells with a target to grow production to 1,500 boe per day at year-end.

IMPROVING HEAVY OIL EFFICIENCY THROUGH WORMHOLE TECHNOLOGY

One of the interesting characteristics of our heavy oil program is the implementation of a cold flow production technique. This technique encourages the production of high sand concentrations of up to 30 percent during the first few months of the well's life. This creates a wormhole in the unconsolidated formation which provides a "pipeline" for the crude oil to more easily flow into the well bore. The well is completed with large perforations and a progressive cavity bottom-hole pump. This type of pump can accommodate the large sand concentrations and still maintain production. During the first few months of production, operating costs on these wells are higher than normal to accomodate the high sand production and lack of solution gas. Over time, the sand cuts fall to less than one percent, production increases and operating costs decline.

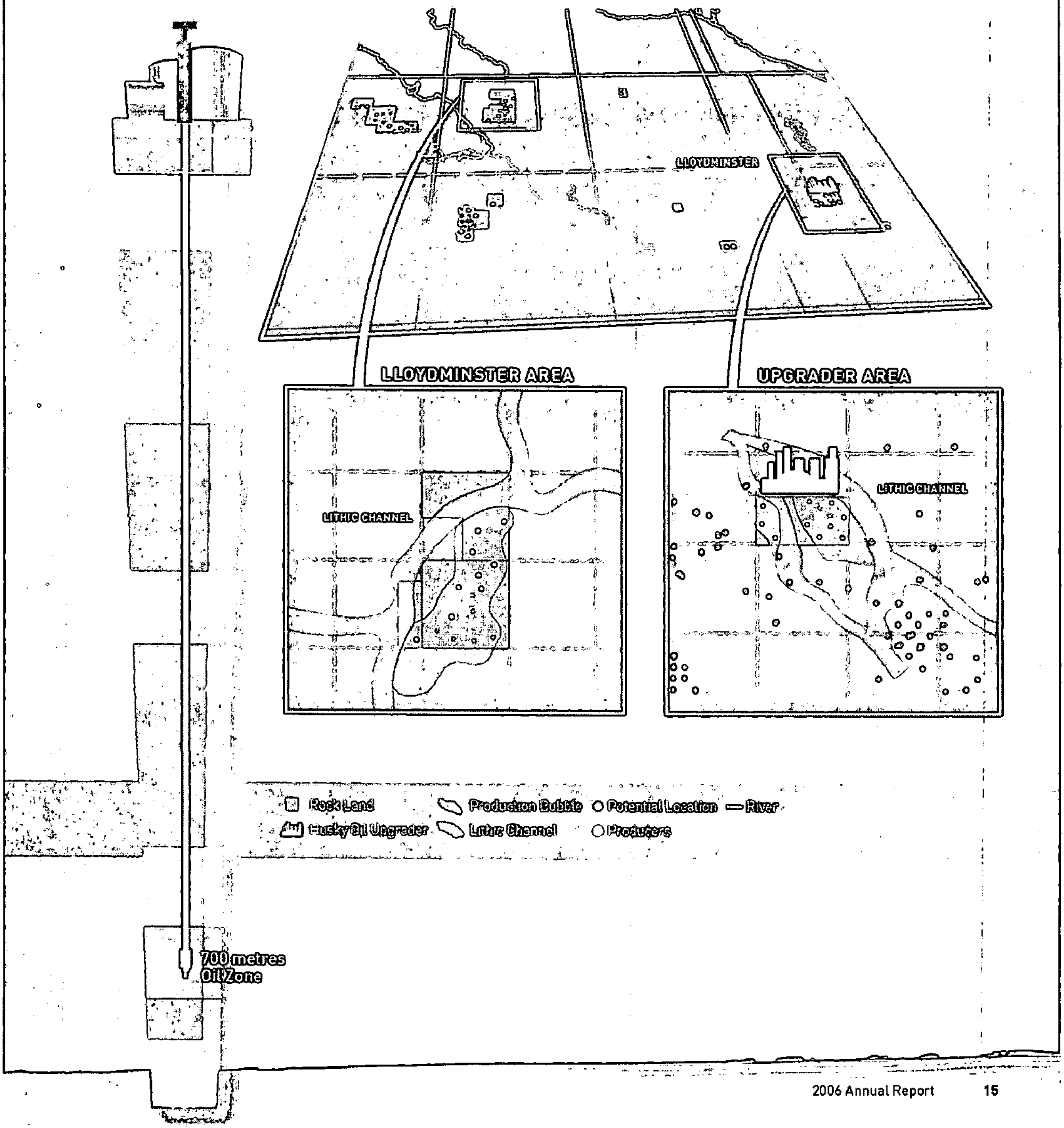
LLOYDMINSTER AREA

In 2006 Rock drilled wells at Lloydminster to confirm and extend various pool boundaries. Drilling costs in this area average $250,000 per well, plus $275,000 to case, complete, equip and bring the well on-production. Wells in this area generally have initial production rates of 50-75 boe per day and ultimately recover over 75,000 barrels of reserves.

UPGRADER AREA

Rock discovered a new pool in the Upgrader area in the fourth quarter of 2006. This is very exciting for the Company. Rock's technical team has identified up to to ten additional drilling locations to delineate this pool, two of which are to be drilled in 2007. Wells in this area are similar to those at Lloydminster, typically costing $525,000 to drill, case, equip, and bring on-production. The oil at the newly discovered Upgrader pool is lighter than at Lloydminster (16° API versus 12° API), with initial production of typically 70-100 boe per day.

LLOYDMINSTER, ALBERTA



PLAINS ALBERTA

CORE AREA

HEAVY OIL ECONOMICS

In 2004 Rock decided to make heavy oil one of its foundation stones. Heavy oil provides Rock with a low-risk, predictable means of adding production, reserves and cash flow. To make this decision we reviewed the project economics of a typical heavy oil play that one could expect in the Lloydminster area. The project assumed that the Company spent funds to acquire some trade 2D seismic, processed the seismic, went to a land sale and bought one section of land for $1 million. The Company would then shoot a grid of 2D seismic and drill eight wells with an 80 percent success rate.

The resulting 6.4 producing wells would have average production of 50 boe per day in the first year and would recover 75,000 boe of reserves over the life of the well. Over their lifecycle the wells would incur an average operating cost of $10.00 per boe and a 25 percent Crown royalty. This project model would generate an F&D cost of $10.00 per boe and a production addition cost of $15,700 per boe per day. Rock compared these costs to the price required to generate a reasonable recycle ratio and rate of return. The graph opposite illustrates recycle ratios versus the price of Lloyd Blend (LLB) crude oil.

In summary, if we can achieve the results discussed above and a realized price of $50.00 per barrel for LLB, we can expect an operating recycle ratio of 2.0. During 2006 Rock incurred an F&D cost of only $7.10 per boe – even better than the model assumptions – while our average LLB price was $50.07 per barrel, slightly above the model. This generated an operating recycle ratio of 2.4 with the actual operating costs and royalties we paid.

As long as we are diligent in managing our costs and our target reserve size relative to the prices we are receiving, heavy oil can generate solid economic returns from a portfolio of low-risk, predictable projects.

MARKET CONDITIONS

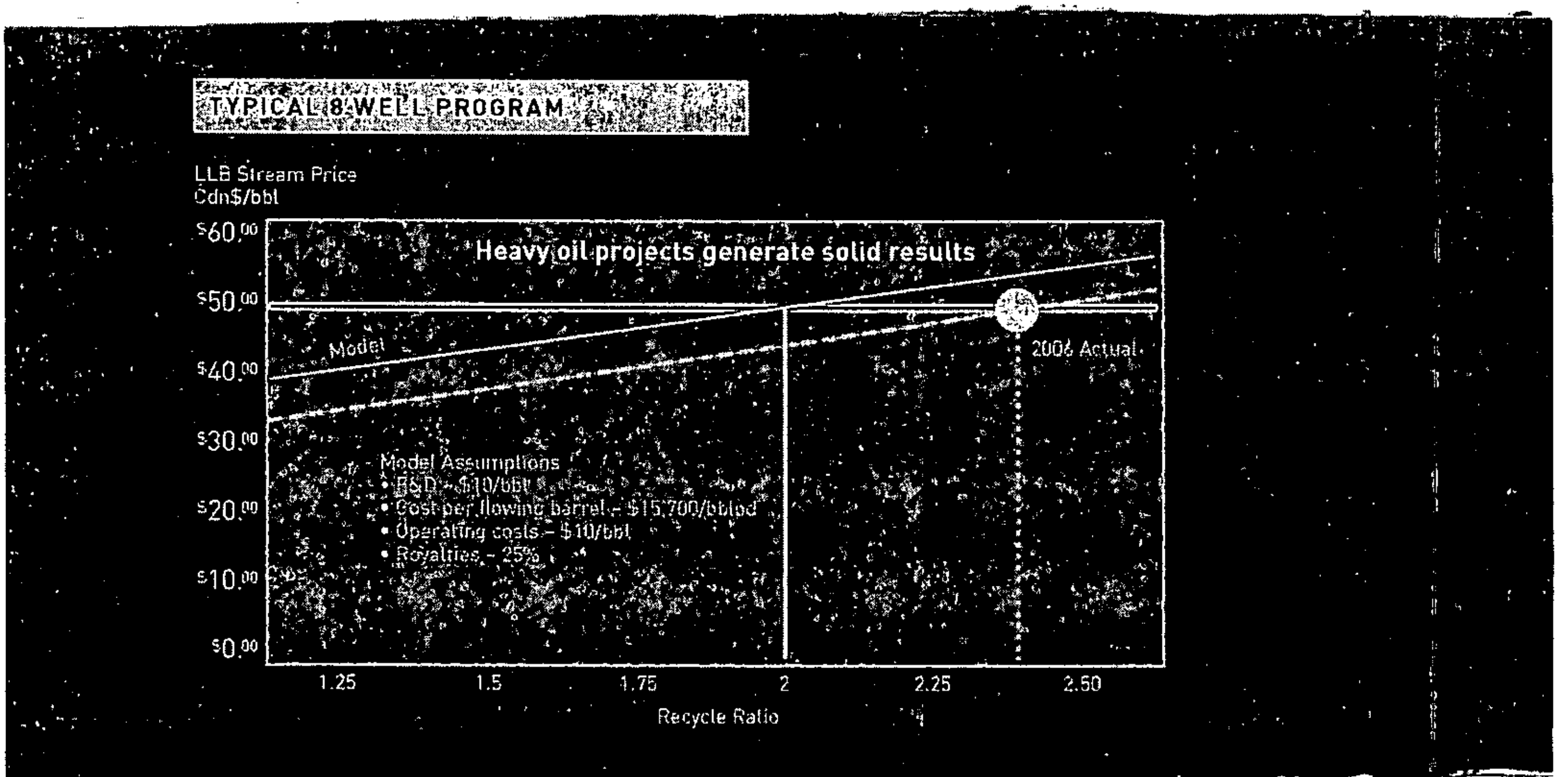
Integral to Rock's heavy oil strategy is a positive view on pricing. When reviewing the market conditions for heavy oil we discovered significant changes in three areas: pipeline take-away capacity was increasing, refinery upgrading capacity was increasing, and non-Canadian heavy oil supply to the U.S. marketplace was decreasing. All of these are favourable to heavy oil prices in Canada.

During the first quarter of 2006 two pipelines in the U.S. were reversed (Exxon Mobil and Spearhead), allowing Canadian heavy oil to reach markets in the mid-continent and the Gulf Coast of the United States from Chicago. Immediately following these pipeline reversals, the heavy-light oil price differential decreased from US$35.00 per barrel to US$20.00 per barrel and has remained favourable. Since that time, more pipeline expansions have been announced to accommodate increased bitumen production from Alberta's oil sands projects. We expect these new projects will also significantly benefit the market access and, consequently, the pricing for conventional heavy crude oil production from Canada.

In addition to improved market access, we expect demand for heavy oil to increase. Globally, many new grassroots upgrading projects and expansions are planned to come on-stream in the 2007 to 2011 timeframe including many in Canada and in the U.S. The world's crude oil is generally becoming heavier and the refining complex is responding to accommodate it.

Supply of conventional heavy crude oil in Canada is forecast to remain relatively flat for the next few years, while bitumen supply from the oil sands is expected to increase. Canadian conventional heavy crude oil competes in the U.S. marketplace at Chicago, the Mid Continent of the U.S., and in the Gulf Coast with Mexican Maya, Venezuelan Heavy, and Middle East Heavy. In recent news we have observed a reduction in supply to the U.S. from Mexico, as the Cantarell field is reportedly in steep decline, and from Venezuela, due to the effects of oil industry nationalization. In addition, as OPEC implements production cuts to defend its price basket, it will cut the heavy barrels first.

The factors discussed above have been carefully considered in forecasting heavy oil pricing. Rock believes that during the next few years the heavy oil price will remain favourable, and that we can expect an LLB price of at least $50.00 per barrel. Rock will continue to build our inventory of heavy oil drilling locations.



WEST CENTRAL ALBERTA
CORE AREA

A STACKED GAS PLAY WITH 3 RISK CATEGORIES

Rock originally entered the West Central core area through its acquisition of Elm/Optimum/Qwest in 2005. Following that acquisition Rock held 7,300 net acres of undeveloped land with an average working interest of 30 percent, and with no operated plays or production. The technical team's focus on this area in 2006 succeeded in building Rock's land position to 11,300 net acres. More important though, we were able to increase Rock's average working interest to 45 percent and to increase the Company's inventory of projects to 25-30 drilling locations, half of which could be operated by Rock.

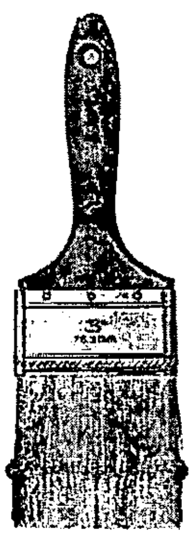
Our team has previous technical experience in this area and we were particularly attracted to the reserve potential and the stacked nature of the productive hydrocarbon-bearing zones. In this region, we are exploring for Cretaceous stratigraphic traps at depths of 1,500-3,000 metres. These targets are part of the Alberta Deep Basin, an extensive trend along the Foothills of the Rocky Mountains which is known for its long-life production and resource-play characteristics.

In 2006 Rock spent $17.1 million, including $5.8 million on land and seismic, and drilled seven (2.2 net) wells, resulting in four (1.4 net) natural gas wells, two (0.7 net) oil wells and one (0.1 net) dry hole. In addition we operated the re-entry of one gas well (0.75 net). Currently, Rock's West Central core area production is 700 boe per day, plus 300 boe per day of productive natural gas capability that is scheduled to come on-stream in November 2007.

A PORTFOLIO OF RISK AND REWARD

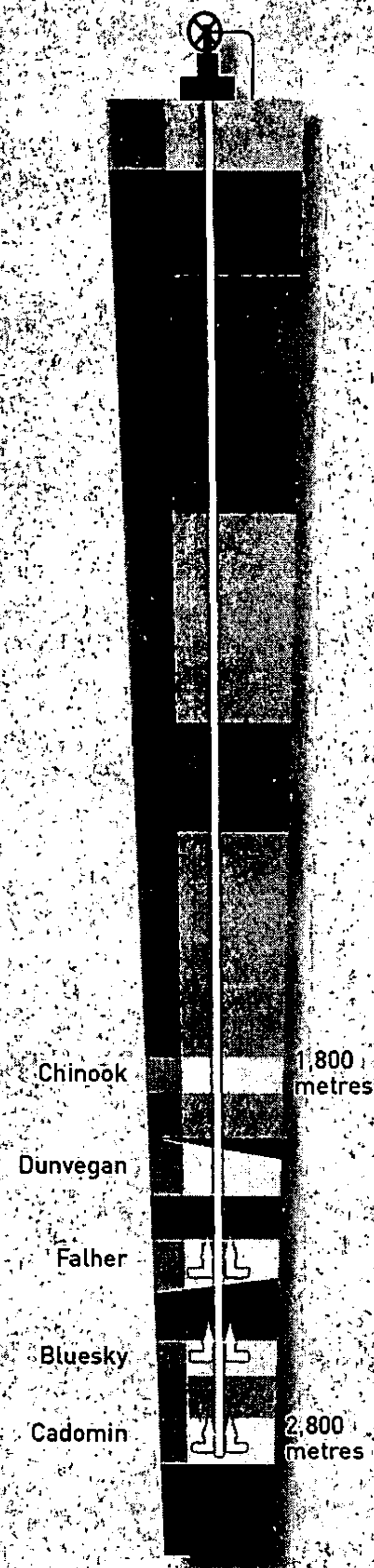
Rock's strategy has always been to develop a portfolio of projects with a range of risk and reward characteristics. In the West Central region we have established a low-risk exploitation program in the Musreau area. Projects in this area include tying-in productive wells, debottlenecking pipeline and compressor operations, in-fill drilling to two wells per section, and completing and commingling up-hole zones in existing well bores.

We have also built a significant inventory of medium-risk exploration projects in the greater Kaybob area. These projects include step-out exploration wells from existing producing wells identified by 2D seismic. To complete our portfolio, in Kakwa we have identified two higher-risk exploration targets which have the potential to significantly increase our production and reserve base.



STACKED GAS PRODUCTION

Exploration in this area can be higher-risk with higher reward potential. To mitigate risk we concentrate on multi-zone stacked gas plays and adjust our working interest participation accordingly. By finding a geological setting that provides more than one productive horizon, we significantly reduce risk and improve results. The best wells can be productive in two or more zones, increasing the reward. Conversely, when the primary target is unproductive the well can often be completed in a secondary zone, protecting the well's economics. In addition, the new commingling regulations approved by the Alberta government in 2006 for this area enable companies to combine production from multiple zones during initial completion operations, reducing completion costs and increasing initial well productivity.



RISK CATEGORY 1: MUSREAU, ALBERTA

LOW-RISK EXPLOITATION THROUGH DOWNSPACING AND UP-HOLE GAS

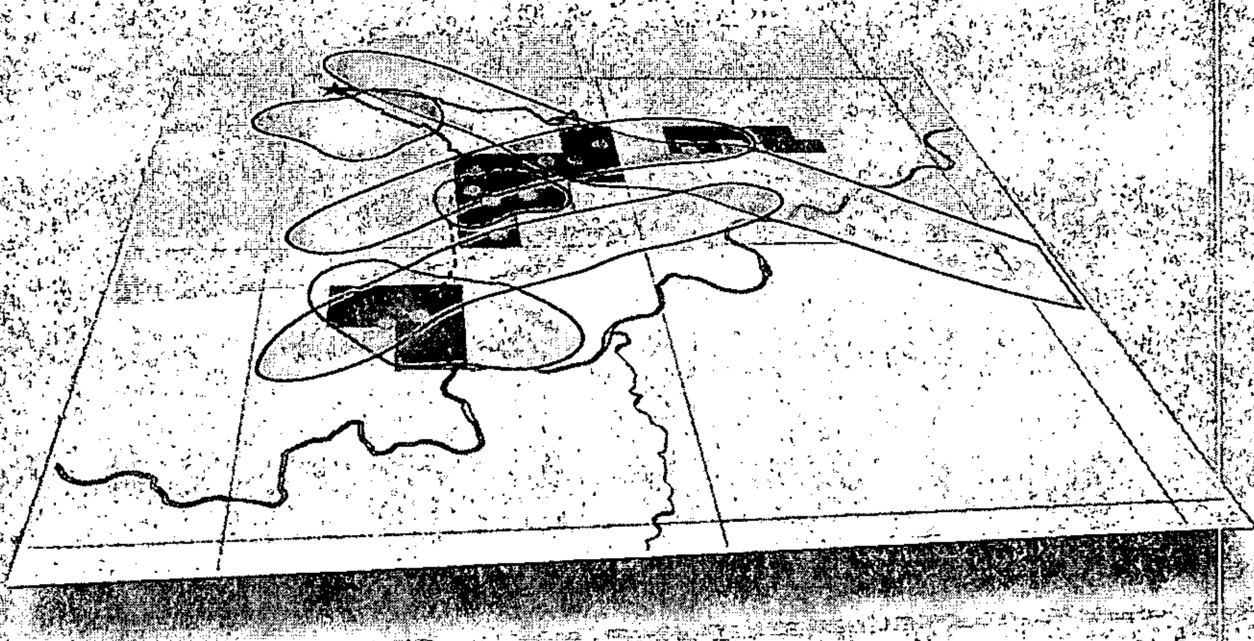
In the Musreau area Rock had 325 boe per day of production on-stream in March 2007. In 2006 Rock spent $9.4 million and participated in drilling two (1.1 net) natural gas wells and one (0.75 net) re-entry. This established 300 boe per day of net productive capacity. Wells in the Musreau area are generally drilled to a total depth of 3,000-3,300 metres at a cost of up to $3.5 million, with a total cost to drill, complete, equip and tie-in of up to $6.0 million. Rock's working interest varies from 7.5-75 percent and averages 25 percent. These wells generally have an initial production rate of 2-4 mmcf per day and can produce a total of 3-5 billion cubic feet of gas over a long reserve life.

The 2007 exploitation program at Musreau includes the following projects:

- Gas plant expansion by the area mid-stream operator;
- Gathering system expansion;
- Production optimization of existing wells;
- Tie-in of standing gas wells;
- Downspacing and infill drilling to two wells per section, with six potential locations (three of which are expected to be drilled in 2007);
- Completing up-hole zones; and
- Commingling producing zones to reduce completion costs and increase production.

The production growth potential for Rock at Musreau is significant. The tie-in of our tested wells is expected to increase production from the current 325 boe per day to 625 boe per day net. Our working interest share of the downspacing and up-hole gas re-completion/ commingling projects should add another 150 boe per day net, providing total potential of more than 750 boe per day net.

MUSREAU, ALBERTA



INFRASTRUCTURE IS BEING ADDRESSED

One of the main considerations in developing a production base in the West Central region is access to processing capacity. In our Musreau area, we encountered some difficulty in getting our gas on-stream as the third-party processing facilities became fully utilized. With 300 boe per day of productive capacity awaiting access to facilities, and an exploitation program that could increase production by another 150 boe per day, we are planning to nominate for firm capacity in a plant expansion. This expansion is proceeding, and we expect to have our production on-stream by November 2007. We also expect to have additional capacity available to accommodate our exploitation plans for the area as we participate in the expansion of gathering system and compression facility projects in the area. Acquisition of this processing capacity is a key strategic accomplishment for Rock, and lays the foundation for further production growth in this area.

RISK CATEGORY 2: KAYBOB, ALBERTA

MODERATE RISK STEP-OUT WELLS

In the greater Kaybob area Rock has been focused on building a strong inventory of moderate-risk exploration projects. We have been successful at land sales, increasing our inventory of drilling locations to more than 10 during the last year. Our average working interest has increased to 45 percent and we are currently the operator in nine of the 10 identified drilling locations.

A well in the Kaybob area typically costs $1.2 million to drill with a total cost to drill, complete, equip and tie-in of $2.2 million. These wells are also targeting stacked Cretaceous formations and will generally have initial production rates of 1-2 mmcf per day and recover a total of 1-3 billion cubic feet of gas over their productive life. Rock is excited about our exploration plans in this area as the drilling costs are lower than in Musreau, but the target size is significant. However, these are step-out exploration wells, so the chance of success needs to be considered in our overall portfolio of opportunities.

During 2007 we expect to spend $3.8 million, drilling three to five locations and continuing to build our inventory of land and opportunity.

RISK CATEGORY 3: KAKWA, ALBERTA

HIGHER RISK/REWARD EXPLORATION

The exploration play at Kakwa provides Rock with significant growth potential where we hold a 30 percent working interest in seven sections of land. In 2006 Rock operated the shooting of an extensive 3D seismic program over these lands, which substantiated the exploration concept. Our technical team has interpreted this data in conjunction with the geological leads and is very excited about testing two prospects this year.

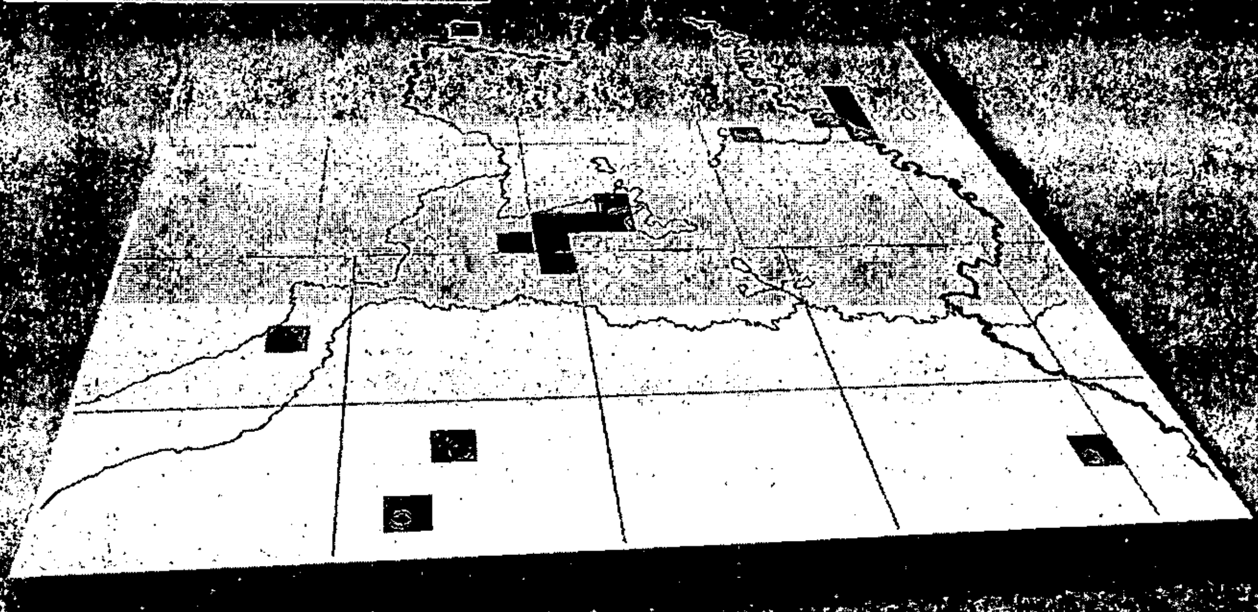
Our main targets in this play include the Bluesky, Falher and Dunvegan formations. Secondary zones include the Cadomin, Cardium and Chinook. These are deep tests down to 3,300 metres with the opportunity to test six to eight zones each.

The typical cost to drill and test is $3.0 million and, if successful, another $2.8 million to complete, equip and tie-in. We expect wells to come on-stream at typically 2-4 mmcf per day and produce 6-10 billion cubic feet of reserves, consistent with analog pools in the area, though a well immediately west of Rock's locations has experienced initial productive rates up to 30 mmcf per day.

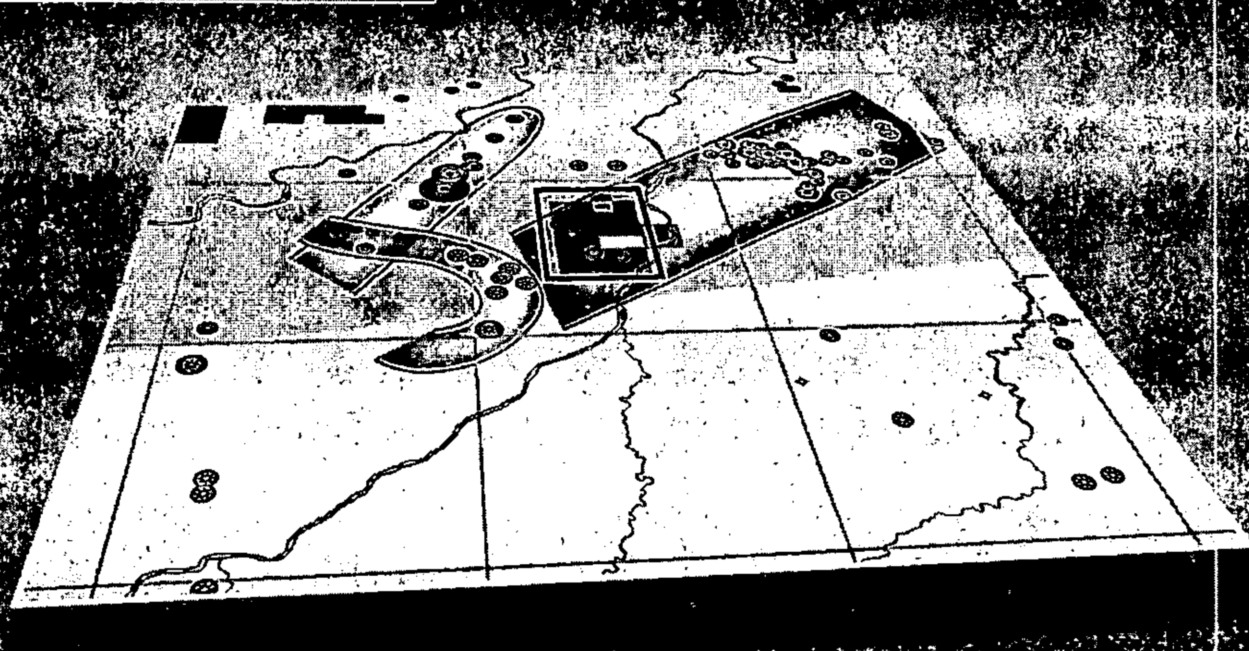
In 2007 Rock is participating in two (0.6 net) independent exploration drilling locations. The first of the exploration wells began drilling on January 26, 2007 and has been cased. It is scheduled to be completed in March and tested in July, as weather and ground conditions permit. The second well is scheduled to begin drilling in August.

The Kakwa project has the potential to significantly increase the production and reserve base of Rock. We have established a number of potential zones which, if proved productive, could be followed up with delineation drilling and then downspacing on the existing land base. Once we have achieved exploration success and are able to estimate an expected on-stream date for one or more new wells, we will update our guidance.

KAYBOB, ALBERTA



KAKWA, ALBERTA



Rock Land
Dunvegan Production Bubble
Potential Location
River
Dunvegan Trends
3D Seismic Coverage
Producers

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 discussion and analysis is dated March 15, 2007 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, 2006.

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 are 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 7, 2006 for projected 2006 and 2007 results. The table below provides the guidance for 2006 with actual results.

2006 Guidance

	2006 Guidance	Actual	Change
2006 Production (boe/d)			
Annual	2,100	2,098	0%
Exit	2,200-2,400	2,200	(4)%
2006 Funds from Operations			
Annual	$13.5 million	$13.9 million	3%
Annual (per share)	$0.69	$0.71	3%
2006 Capital Budget			
Expenditures	$30 million	$33 million	10%
Gross wells drilled	31	33	6%
Total net debt at year-end	$11 million	$12.6 million	15%
Pricing (Fourth Quarter)			
Oil – WTI	US$60.00/bbl	US$60.21/bbl	0%
Natural gas – AECO	$6.67/mcf	$6.69/mcf	0%
US/Cdn $ exchange rate	0.90	0.88	(2)%

Production averages for the year and the exit rate were within the guidance range. Funds flow from operations was above guidance as higher pricing (lower than budgeted heavy oil differentials and higher realized natural gas prices) more than offset higher operating costs. Capital expenditures were higher than forecast as $2 million of the 2007 capital budget was accelerated into December 2006 in order to take advantage of rig availability and operational efficiencies to drill four (4.0 net) heavy oil wells. As a result debt levels at year-end were slightly above guidance.

Guidance for 2007 has been updated to reflect higher operating costs experienced by the Company and industry and acceleration of the 2007 capital budget into December 2006. The table below updates the Company's previous guidance that was issued November 7, 2006.

	2007 Previous Guidance	2007 Revised Guidance	Change
2007 Production (boe/d)			
Annual	2,200	2,200-2,400	5%
Exit	2,600-2,800	2,600-2,800	0%
2007 Funds from Operations			
Annual	$15 million	$15 million	0%
Annual (per share)	$0.76	$0.76	0%
2007 Capital Budget			
Expenditures	$22 million	$20 million	(9)%
Gross wells drilled	20-25	16-21	(18)%
Total net debt at year-end	$18 million	$18 million	0%
Pricing (Annual)			
Oil - WTI	US$65.00/bbl	US$65.00/bbl	0%
Natural gas - AECO	Cdn$7.50/mcf	Cdn$7.50/mcf	0%
US/Cdn $ exchange rate	0.90	0.90	0

Operating costs have been trending up and, as a result, Rock has increased the per boe cost by $0.50/boe to approximately $11.25 per boe including transportation costs. The acceleration of capital into December 2006 has caused management to implement an annual average range for production as the wells drilled came on-stream in the first quarter instead of the third quarter. The annual cash flow associated with the increased production has been offset by the increase in operating costs. As a result, the year's cash flow and year-end debt levels have not been affected. While light oil pricing has initially been lower than forecast for 2007, heavy oil differentials have improved and, as a result, we have not altered our oil price. The Company has put in a new debt facility which increased the bank line from $18 million to $23 million. Capital expenditures in excess of funds from operations are projected to be $5 million and can be funded through this facility. The year-end debt to cash flow ratio is projected to be approximately 1.2:1. 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.

Production by Product

	12 Months Ended 12/31/06	12 Months Ended 12/31/05	Change	3 Months Ended 12/31/06	3 Months Ended 12/31/05	Quarterly Change
Natural gas (mcf/d)	**6,421**	4,476	43%	3,528	8,147	(57)%
Oil (bbls/d)	**179**	133	35%	206	207	(1)%
Heavy oil (bbls/d)	**792**	187	324%	1,168	480	143%
NGL (bbls/d)	**57**	56	2%	42	75	(44)%
Total (boe/d) (6:1)	**2,098**	1,122	87%	2,004	2,120	(5)%

Production by Area

	12 Months Ended 12/31/06	12 Months Ended 12/31/05	Change	3 Months Ended 12/31/06	3 Months Ended 12/31/05	Quarterly Change
West Central Alberta (boe/d)	**972**	598	63%	652	1,189	(45)%
Plains (boe/d)	**795**	242	229%	1,171	510	130%
Other (boe/d)	**331**	282	17%	181	421	(57)%
Total (boe/d) (6:1)	**2,098**	1,122	87%	2,004	2,120	(5)%

Production increases for the year ended December 31, 2006 primarily came from two sources. First are the ELM/Optimum/Qwest acquisitions that were completed in stages and closed in April and June 2005, partially offset by the sale of approximately 820 boe per day of production in July 2006. Second, the Company's operated grassroots drilling program contributed the heavy oil additions in the Plains area and additional production from drilling on the acquired properties. Early in January 2007 Rock's production exceeded 2,200 boe per day.

Production decreased by 5 percent in the fourth quarter of 2006 from the same period last year as the property dispositions in the third quarter more than offset the additions from operational activities. Production additions in the quarter primarily came from the Plains core area, which added heavy oil production, and the workovers completed at Medicine River, which added light oil production. As a result of these activities the Company's product mix shifted more towards heavy oil.

Product Prices

	12 Months Ended 12/31/06	12 Months Ended 12/31/05	Change	3 Months Ended 12/31/06	3 Months Ended 12/31/05	Quarterly Change
Realized Product Prices						
Natural gas ($/mcf)	**7.07**	10.22	(31)%	7.45	12.06	(38)%
Oil ($/bbl)	**64.46**	64.95	(1)%	57.77	63.63	(9)%
Heavy oil ($/bbl)	**38.35**	27.44	40%	34.86	24.81	41%
NGL ($/bbl)	**61.35**	56.19	9%	65.47	58.80	11%
Combined average ($/boe) (6:1)	**43.27**	55.85	(23)%	40.73	60.29	(32)%

	12 Months Ended 12/31/06	12 Months Ended 12/31/05	Change	3 Months Ended 12/31/06	3 Months Ended 12/31/05	Quarterly Change
Average Reference Prices						
Natural gas – Henry Hub Daily Spot (US$/mcf)	**6.75**	8.89	(24)%	6.69	12.27	(45)%
Natural gas – AECO C Daily Spot ($/mcf)	**6.54**	8.77	(25)%	6.99	11.43	(39)%
Oil – WTI Cushing, Oklahoma (US$/bbl)	**66.22**	56.56	17%	60.21	60.02	0%
Oil – Edmonton Light ($/bbl)	**72.77**	68.72	6%	64.49	71.17	(9)%
Heavy Oil – Lloydminster blend ($/bbl)	**50.07**	42.99	16%	43.84	41.81	5%
US/Cdn $ exchange rate	**0.882**	0.826	7%	0.878	0.852	3%

For the year and quarter ended December 31, 2006 the Company experienced higher heavy oil prices (approximately 40 percent increase) and lower natural gas prices (more than 30 percent reduction) than in the prior year's periods. Higher heavy oil prices resulted from higher WTI prices for the year and a significant decrease in the heavy oil to light oil differential. Structural changes in the marketplace such as pipeline reversals that have taken more heavy crude production out of Alberta to refineries in the mid-continent United States have contributed to the improvement in the heavy oil differential. The Company expects that these and other structural changes will continue to benefit the heavy oil market price. Natural gas prices have suffered from high storage levels as winter was delayed and the fourth quarter of 2006 was warmer than average. The combination of lower natural gas prices and the increase in heavy oil production in Rock's product mix over 2005 has caused the Company's weighted average per boe price to decrease by 23 percent for the year and 32 percent for the fourth quarter from the prior year's periods.

REVENUE

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

Oil and Natural Gas Revenue

	12 Months Ended 12/31/06	12 Months Ended 12/31/05	Change	3 Months Ended 12/31/06	3 Months Ended 12/31/05	Quarterly Change
Natural gas	**$ 16,560**	$ 16,695	(1)%	$ 2,408	$ 9,043	(73)%
Oil	**4,195**	3,152	33%	1,073	1,214	(12)%
Heavy oil	**11,124**	1,871	495%	3,790	1,095	246%
NGL	**1,277**	1,155	11%	264	408	(35)%
	33,156	22,873	45%	7,535	11,760	(36)%
Other revenue	**$ 198**	$ 317	(38)%	$ 42	$ 100	(58)%

Oil and natural gas revenue increased by 45 percent for the year ended December 31, 2006 over 2005 due to higher production levels, particularly of heavy oil, which more than offset the decline in product prices, particularly of natural gas. For the fourth quarter of 2006 oil and natural gas revenue decreased by 36 percent from the same period in 2005 as lower natural gas production and prices more than offset the increase in heavy oil production and prices. Other revenue decreased in 2006 from 2005 as the Company sold the property that was generating sulphur as part of the asset rationalization program in the third quarter of 2006.

Royalties

	12 Months Ended 12/31/06	12 Months Ended 12/31/05	Change	3 Months Ended 12/31/06	3 Months Ended 12/31/05	Quarterly Change
Royalties	**$ 6,881**	$ 5,027	37%	$ 1,452	$ 2,666	(46)%
As a percentage of oil and natural gas revenue	**20.8%**	22.0%	(5)%	19.3%	22.7%	(15)%
Per boe (6:1)	**$ 8.98**	$ 12.28	(27)%	$ 7.88	$ 13.67	(42)%

Royalties increased for the year ended December 31, 2006 over the prior year due to higher production levels partially offset by lower natural gas prices and the benefit of Alberta Royalty Tax Credit (ARTC). For the fourth quarter of 2006 royalties decreased from the fourth quarter of 2005 due to lower production, lower natural gas prices and the ARTC benefit. Royalties as a percentage of revenue and on a per-boe basis decreased in the 2006 periods from the 2005 periods primarily due to lower natural gas prices, ARTC benefit and the Company's production mix including a higher heavy oil component, which generally has a lower associated royalty rate. The Company is forecasting a royalty rate of 22 percent for 2007 as the ARTC program has been eliminated effective January 1, 2007.

Operating Expenses

	12 Months Ended 12/31/06	12 Months Ended 12/31/05	Change	3 Months Ended 12/31/06	3 Months Ended 12/31/05	Quarterly Change
Operating expense	**$ 8,947**	$ 4,470	100%	$ 2,429	$ 2,149	13%
Transportation costs	**308**	275	12%	83	158	(47)%
	9,255	4,745	95%	2,512	2,307	9%
Per boe (6:1)	**$ 12.08**	$ 11.59	4%	$ 13.63	$ 11.83	15%

Operating costs for the year ended December 31, 2006 have increased over 2005 primarily due to higher production. Operating expenses for both the year ended December 31, 2006 and the fourth quarter of 2006 include approximately $200 of natural gas processing costs related to 2005. Excluding these prior-period processing costs, operating costs for 2006 are $11.83 per boe, a 2 percent increase over 2005, and $12.56 per boe for the fourth quarter of 2006, a 6 percent increase over the prior period. Compared to the third quarter of 2006, fourth quarter per boe operating expenses have decreased by 4 percent once the 2005 processing costs are excluded. Operating costs per boe did not decrease as much as expected in the fourth quarter in part due to higher service costs associated with heavy oil operations and higher road and lease maintenance costs.

Heavy oil unit costs tend to be higher in the first several months of producing operations (the "clean-up period") due to high initial sand production, additional fuel costs incurred until the operation is capable of running on casing-head gas and injected load oil being used during the clean-up period, which reduces the sales volume from the operations. Heavy oil operating costs have decreased year-over-year by about 20 percent to about $13.00 per boe as the base level of production has increased and start-up operations have less of an impact on overall costs. The Company expects heavy oil costs per boe to continue to decrease in 2007. Transportation costs for the fourth quarter of 2006 decreased from the prior year's period as a result of the properties sold in the third quarter of 2006. Operating expenses per boe, including transportation expense, are forecast to be approximately $11.25 per boe in 2007.

General and Administrative (G&A) Expense

	12 Months Ended 12/31/06	12 Months Ended 12/31/05	Change	3 Months Ended 12/31/06	3 Months Ended 12/31/05	Quarterly Change
Gross	**$ 3,905**	$ 2,275	69%	$ 1,085	$ 814	27%
Per boe (6:1)	**5.10**	5.55	(9)%	5.89	4.17	34%
Capitalized	**1,627**	864	83%	395	288	19%
Per boe (6:1)	**2.12**	2.11	(2)%	2.14	1.47	26%
Net	**2,278**	1,411	61%	690	526	31%
Per boe (6:1)	**$ 2.97**	$ 3.44	(14)%	$ 3.74	$ 2.70	39%

G&A expense increased on an absolute basis in 2006 over 2005 as the Company's operations continued to grow and new staff was added. G&A expense on a per-boe basis for the year ended December 31, 2006 dropped from the prior year's period as production increased. For the fourth quarter of 2006, G&A expense per boe increased over 2005 as production decreased as a result of the property dispositions in the third quarter of 2006, because costs for year-end activities increased and because approximately $56 ($0.30 per boe) of bad debt related to the ELM/Optimum/Qwest acquisition was written off. Rock capitalizes certain G&A expenses based on personnel involved in the exploration and development initiatives, including salaries and related overhead costs. G&A expenses are expected to rise in 2007 on an absolute basis as industry costs increase.

Interest Expense

	12 Months Ended 12/31/06	12 Months Ended 12/31/05	Change	3 Months Ended 12/31/06	3 Months Ended 12/31/05	Quarterly Change
Interest expense (recovery)	**$ 924**	$ 457	100%	$ 141	$ 261	(46)%
Per boe (6:1)	**$ 1.21**	$ 1.12	8%	$ 0.76	$ 1.34	(43)%

Interest expense for 2006 doubled over 2005 as a result of higher average bank debt for the year. For the fourth quarter of 2006 interest expense was about half of interest expense for the same period of 2005 as bank debt was reduced in the third quarter of 2006 with proceeds from the asset rationalization program. Interest expense is expected to increase in 2007 due to higher average bank debt but to be approximately the same on a per-boe basis as in 2006.

Depletion, Depreciation, and Accretion (DD&A)

	12 Months Ended 12/31/06	12 Months Ended 12/31/05	Change	3 Months Ended 12/31/06	3 Months Ended 12/31/05	Quarterly Change
D&D expense	**$ 13,989**	$ 8,211	70%	$ 2,707	$ 3,994	(32)%
Per boe (6:1)	**$ 18.27**	$ 20.05	(9)%	$ 14.69	$ 20.48	(28)%
Accretion expense	**$ 129**	$ 76	70%	$ 34	$ 31	10%
Per boe (6:1)	**$ 0.17**	$ 0.19	(11)%	$ 0.18	$ 0.16	13%

Depletion and depreciation expense for year ended December 31, 2006 increased over the prior year due to higher production but decreased for the fourth quarter of 2006 from the 2005 period primarily as Company reserves increased faster than the cost base. Reserve additions in 2006 also caused the depletion and depreciation expense per boe to decrease in 2006 from 2005.

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 or constructing facilities. Similarly, this obligation can also be reduced as a result of abandonment work undertaken and reducing future obligations. During the year ended December 31, 2006 capital programs increased the underlying ARO by $413 (December 31, 2005 – $1,583) and actual expenditures on abandonments were $104 (December 31, 2005 – $44).

INCOME TAX

The Company began to pay capital taxes in 2005 as its capital base increased significantly following the acquisitions in 2005. Federal large corporations tax was eliminated beginning in 2006; however, 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 2007 as the Company and its subsidiaries have estimated resource and other pools available at December 31, 2006 (after the allocation of deferred partnership income) of approximately $55.2 million as set out below:

CEE	$	14.9 million
CDE	$	25.9 million
UCC	$	12.8 million
Loss carry-forwards	$	0.3 million
Other	$	1.3 million
Total	$	55.2 million

Funds from Operations and Net Income

	12 Months Ended 12/31/06	12 Months Ended 12/31/05	Change	3 Months Ended 12/31/06	3 Months Ended 12/31/05	Quarterly Change
Funds from operations	**$ 13,867**	$ 11,433	21%	$ 2,644	$ 6,020	(56)%
Per boe (6:1)	**$ 18.11**	$ 27.92	(35)%	$ 14.35	$ 30.86	(54)%
Per share:						
Basic	**$ 0.71**	$ 0.74	(4)%	$ 0.13	$ 0.31	(58)%
Diluted	**$ 0.71**	$ 0.74	(4)%	$ 0.13	$ 0.31	(58)%
Net income (loss)	**$ (884)**	$ 1,510	(159)%	$ (119)	$ 747	(116)%
Per boe (6:1)	**$ (1.15)**	$ 3.69	(131)%	$ (0.65)	$ 3.83	(117)%
Per share:						
Basic	**$ (0.05)**	$ 0.10	(150)%	$ (0.01)	$ 0.04	(125)%
Diluted	**$ (0.05)**	$ 0.10	(150)%	$ (0.01)	$ 0.04	(125)%
Weighted average shares outstanding:						
Basic	**19,637**	15,437	27%	19,637	19,596	0%
Diluted	**19,655**	15,501	27%	19,637	19,682	0%

The Company did not issue any shares in 2006. In 2005 the majority of shares issued were for the acquisitions completed in the second quarter of 2005, when 10.3 million shares were issued.

Funds from operations for the year ended December 31, 2006 increased by 21 percent over 2005 as the increase in production more than offset the decrease in realized prices, primarily for natural gas, and the increase in royalties, operating, G&A and interest costs. On a per-boe basis 2006 funds from operations decreased by 35 percent from 2005 primarily as the reduction in realized prices more than offset the reduction in royalties. For the fourth quarter of 2006 funds from operations decreased by approximately 56 percent on an absolute and 54 percent on a per boe-basis from the prior year's periods as the reduction in prices (primarily for natural gas) and increase in operating and G&A costs more than offset the reduction in royalties. The Company generated a net loss for the year and quarter ended December 31, 2006 as the level of depletion and increase in stock-based compensation exceeded funds from operations.

Capital Expenditures

($000)	**12 Months Ended 12/31/06**	12 Months Ended 12/31/05	Change	3 Months Ended 12/31/06	3 Months Ended 12/31/05	Quarterly Change
Land	**$ 4,822**	$ 3,737	29%	$ 120	$ 1,664	(93)%
Seismic	**1,081**	1,761	(39)%	127	878	(86)%
Drilling and completions	**25,130**	16,801	50%	5,758	5,783	0%
Capitalized G&A	**1,627**	865	88%	395	288	37%
Gas gathering systems	**247**	7	3,429%	–	35	(99)%
Total operations	**$ 32,907**	$ 23,171	42%	$ 6,400	$ 8,648	(26)%
Property acquisitions (dispositions)	**(30,874)**	60,593	(151)%	Nil	Nil	n/a
Well site facilities inventory	**(165)**	401	(141)%	(206)	(895)	(77)%
Office equipment	**136**	72	89%	39	15	160%
Total (net of acquisitions and dispositions)	**$ 2,004**	$ 84,237	(98)%	$ 6,233	$ 7,768	(20)%

Capital expenditures for operations increased for the year ended December 31, 2006 over 2005 as Rock drilled the same number of gross wells (33) but more net wells (28.3 in 2006 versus 22.4 in 2005) as the Company gained more control over its operations. The Company participated in more West Central core area operations, including re-completions and, as a result, drilling and completions costs increased by 50 percent. In total Rock participated in nine (6.1 net) re-completions, which included one (0.8 net) natural gas well in the Musreau area which is expected to be tied-in in the fourth quarter of 2007, when third-party facilities are expanded, and one (1.0 net) oil well at Medicine River, which was brought on-production in the fourth quarter of 2006.

Land expenditures increased as the Company continued to build its West Central core area presence. Seismic expenditures decreased as the number of programs shot in the Plains core area decreased with Rock's shift to the West Central core area. Total net capital expenditures were reduced to $2 million in 2006 from $84 million in 2005 as the proceeds from the Company's asset rationalization program essentially offset capital expenditures from operations. In 2005 the Company completed the ELM/Optimum/Qwest acquisitions which significantly increased total capital expenditures.

During 2006, Rock drilled 27 (27.0 net) operated wells and six (1.3 net) non-operated wells, achieving a 96 percent success rate, compared to 20 (20.0 net) operated wells and 13 (2.1 net) non-operated wells and an 82 percent success rate in 2005. In the Plains core area Rock drilled 25 (25.0 net) heavy oil wells and one (1.0 net) dry hole. All of the wells were operated and all successful wells were on-production at year-end except four (4.0 net) wells drilled in December 2006, which were brought on-production in the first quarter of 2007. Rock had no production from the Plains area at the beginning of 2005 and exited with approximately 670 boe per day in 2005 and 1,250 boe per day in 2006. In the West Central Alberta core area in 2006 Rock drilled two (0.9 net) oil wells in the Niton area, three (1.2 net) natural gas wells and one (0.1 net) dry hole. Of the three gas wells two (1.1 net) were drilled in the Musreau area and are expected to be tied-in in the fourth quarter of 2007 along with the re-completed well. In aggregate the Musreau-area wells are projected to initially increase Rock's production by 300 boe per day once tied-in. For the fourth quarter of 2006 capital expenditures decreased by approximately $2 million from 2005 levels as land and seismic activity decreased in the quarter.

LIQUIDITY AND CAPITAL RESOURCES

Rock's current approved capital budget for 2007 projects spending of $20 million. In 2007 funds from operations are expected to be approximately $15 million. The capital spending in excess of cash flow is intended to be funded through bank debt. Subsequent to year-end the Company arranged a new $23 million bank facility with a different chartered bank to replace its existing bank facility. With year-end debt of $12.6 million Rock has room to fund the $5 million of capital expenditures in excess of expected cash flow for 2007. The new bank facility will be reviewed by April 30, 2007 with the Company's 2006 independent reserve report. Based on the drilling in the fourth quarter of 2006, Rock expects, subject to any changes to the bank's commodity price forecast, an increase to the borrowing base. The Company will continue to monitor capital expenditures, cash flow from operations and debt levels and make adjustments, in order to ensure the projected debt to cash flow ratio does not exceed 1.5:1.

The Company has a demand operating loan facility with a Canadian chartered bank. This facility was put in place subsequent to year-end with a new lender and the Company's previous facility was repaid. The new facility is subject to the bank's valuation of the Company's oil and natural gas assets and the credit currently available is $23 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 facility is currently under its annual review. As at March 15, 2007 approximately $14.7 million was drawn under the facility.

SELECTED ANNUAL DATA

The following table provides selected annual information for Rock. The Company changed its year-end at December 31, 2004 from March 31, 2004. In order to make comparisons of periods compatible, information presented for the 12-month period ended December 31, 2004 has been compiled by combining the nine-month period ended December 31, 2004 with the three-month period ended March 31, 2004.

	12 Months Ended 12/31/06	12 Months Ended 12/31/05	12 Months Ended 12/31/04
Production (boe/d)	**2,098**	1,122	181
Oil and natural gas revenues ($000)	**$ 33,156**	$ 22,873	$ 2,845
Average realized price ($/boe)	**$ 43.27**	$ 55.85	$ 43.02
Royalties ($/boe)	**$ 8.98**	$ 12.28	$ 9.89
Operating expense ($/boe)	**$ 12.08**	$ 11.59	$ 7.97
Operating netback ($/boe)	**$ 22.21**	$ 31.98	$ 25.16
Net G&A expense ($000)	**$ 2,278**	$ 1,411	$ 959
Stock-based compensation ($000)	**$ 1,188**	$ 485	$ 202
Funds from operations ($000)	**$ 13,867**	$ 11,433	$ 1,218
Per share – basic	**$ 0.71**	$ 0.74	$ 0.14
Per share – diluted	**$ 0.71**	$ 0.74	$ 0.14
Net income (loss)	**$ (884)**	$ 1,510	$ 571
Per share – basic	**$ (0.05)**	$ 0.10	$ 0.06
Per share – diluted	**$ (0.05)**	$ 0.10	$ 0.06
	As at 12/31/06	As at 12/31/05	As at 12/31/04
Total assets	**$ 85,306**	$ 99,604	$ 25,057
Total liabilities	**$ 24,827**	$ 39,385	$ 2,693

SELECTED QUARTERLY DATA

The following table provides selected quarterly information for Rock:

	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)	**2,004**	1,613	2,190	2,594
Oil and natural gas revenues ($000)	**$ 7,535**	$ 7,023	$ 8,774	$ 9,824
Average realized price ($/boe)	**$ 40.73**	$ 47.30	$ 44.01	$ 42.08
Royalties ($/boe)	**$ 7.88**	$ 5.27	$ 8.97	$ 12.26
Operating expense ($/boe)	**$ 13.63**	$ 13.13	$ 10.55	$ 11.55
Operating netback ($/boe)	**$ 19.22**	$ 28.90	$ 24.49	$ 18.27
Net G&A expense ($000)	**$ 690**	$ 477	$ 462	$ 649
Stock-based compensation ($000)	**$ 295**	$ 308	$ 305	$ 280
Funds from operations ($000)	**$ 2,644**	$ 3,791	$ 4,028	$ 3,404
Per share – basic	**$ 0.13**	$ 0.19	$ 0.21	$ 0.17
Per share – diluted	**$ 0.13**	$ 0.19	$ 0.21	$ 0.17
Net income (loss) ($000)	**$ (119)**	$ 891	$ (583)	$ (1,074)
Per share – basic	**$ (0.01)**	$ 0.05	$ (0.03)	$ (0.05)
Per share – diluted	**$ (0.01)**	$ 0.05	$ (0.03)	$ (0.05)
Capital expenditures ($000)	**$ 6,223**	$ 12,520	$ 4,397	$ 9,728

	As at 12/31/06	As at 09/30/06	As at 06/30/06	As at 03/31/06
Working capital ($000)	**$ (12,580)**	$ (8,990)	$ (31,135)	$ (30,766)

	3 Months Ended 12/31/05	3 Months Ended 09/30/05	3 Months Ended 06/30/05	3 Months Ended 03/31/05
Production (boe/d)	2,120	1,343	693	309
Oil and natural gas revenues ($000)	$ 11,760	$ 7,030	$ 2,924	$ 1,159
Average realized price ($/boe)	$ 60.29	$ 56.90	$ 46.36	$ 41.65
Royalties ($/boe)	$ 13.67	$ 11.61	$ 10.39	$ 9.73
Operating expense ($/boe)	$ 11.83	$ 13.19	$ 8.62	$ 9.49
Operating netback ($/boe)	$ 34.79	$ 32.10	$ 27.35	$ 22.43
Net G&A expense ($000)	$ 526	$ 329	$ 282	$ 274
Stock-based compensation ($000)	$ 257	$ 131	$ 55	$ 42
Funds from operations ($000)	$ 6,020	$ 3,552	$ 1,469	$ 392
Per share – basic	$ 0.31	$ 0.18	$ 0.11	$ 0.04
Per share – diluted	$ 0.31	$ 0.18	$ 0.11	$ 0.04
Net income (loss) ($000)	$ 747	$ 634	$ 77	$ 51
Per share – basic	$ 0.04	$ 0.03	$ 0.01	$ 0.01
Per share – diluted	$ 0.04	$ 0.03	$ 0.01	$ 0.01
Capital expenditures ($000)	$ 7,768	$ 7,920	$ 66,411	$ 2,138

	As at 12/31/05	As at 09/30/05	As at 06/30/05	As at 03/31/05
Working capital ($000)	$ (24,442)	$ (22,643)	$ (18,093)	$ 10,297

Production has grown over the last two quarters of 2006 subsequent to the asset rationalization program which was completed in the third quarter of 2006. Immediately following these dispositions Rock's production was approximately 1,400 boe per day. Production growth has primarily come from drilling operations in the Plains core area and well recompletions at the Medicine River property near Sylvan Lake. Over the same period corporate average product prices have decreased as natural gas and oil prices declined. Heavy oil prices decreased in the fourth quarter, as expected, due to seasonality but in general were higher than 2005 levels. Royalty rates have generally improved in 2006 as Rock's product mix became more heavily weighted to oil, which usually has a lower royalty rate than gas, and because of Rock receiving the ARTC benefit.

Operating costs per boe have fluctuated depending on the amount of heavy oil start-up operations in any particular period, and the fourth quarter of 2006 included $200 relating to 2005 gas processing cost adjustments. Without these costs fourth quarter operating costs per boe would have decreased to $12.57 per boe. Field netbacks generally declined in 2006 from 2005 due to lower product prices. G&A expenses continued to rise as staffing levels increased throughout the period as the Company's activity levels grew. Funds from operations and net income or loss have been primarily affected by the change in product prices as changes in operating costs and royalty rates tended to offset each other. Net capital expenditures were significantly impacted by the asset rationalization program in the third quarter of 2006, which generated proceeds of $30.9 million, and by the acquisitions in the second quarter of 2005, which incurred costs of $60.5 million. The second quarter of the year tends to be a slower operational period with respect to capital investments due to the effects of spring break-up.

Reserves

Rock's reserves have been independently evaluated by GLJ Petroleum Consultants Ltd. (GLJ) at year-end 2006. This is the third year in which GLJ has evaluated the Company's reserves. The reserves as at December 31, 2006 and 2005 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 2005 and year-end 2006. NI 51-101 requires reserves to be reconciled on a net basis (after deducting royalties but including any royalty interests) ("net interest"). In addition, in the tables below Rock has also provided a reserve reconciliation on a gross basis (before deducting royalties and without including any royalty interest) ("gross interest").

Rock's gross interest reserves at year-end 2006 are 4.4 million boe of proved reserves and 7.3 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 2.0 million boe of proved reserves and 3.6 million boe of proved plus probable reserves.

RESERVES RECONCILIATION

The following table is a reconciliation of Rock's gross interest reserves at December 31, 2006 using GLJ's forecast pricing and cost estimates as at December 31, 2006.

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

	Oil		NGL		Heavy Oil		Natural Gas		Total Oil Equivalent	
Factors	Proved (mbbls)	Proved Plus Probable (mbbls)	Proved (mbbls)	Proved Plus Probable (mbbls)	Proved (mbbls)	Proved Plus Probable (mbbls)	Proved (mmcf)	Proved Plus Probable (mmcf)	Proved (mboe)	Proved Plus Probable (mboe)
December 31, 2005	331	427	111	146	1,128	2,096	14,427	19,657	3,974	5,946
Additions[1]	121	197	22	53	1,734	2,500	1,825	5,240	2,181	3,624
Technical revisions[2]	36	41	8	6	132	(8)	(218)	(613)	140	(65)
Acquisitions	0	0	0	0	0	0	0	0	0	0
Dispositions	(10)	(12)	(1)	(1)	0	0	(6,186)	(8,358)	(1,042)	(1,406)
Production	(65)	(65)	(21)	(21)	(289)	(289)	(2,342)	(2,342)	(765)	(765)
December 31, 2006	**413**	**588**	**118**	**183**	**2,705**	**4,299**	**7,506**	**13,584**	**4,488**	**7,334**

(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.

The following table is a reconciliation of Rock's net interest reserves at December 31, 2006 using GLJ's forecast pricing and cost estimates as at December 31, 2006.

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

	Oil		NGL		Heavy Oil		Natural Gas		Total Oil Equivalent	
Factors	Proved (mbbls)	Proved Plus Probable (mbbls)	Proved (mbbls)	Proved Plus Probable (mbbls)	Proved (mbbls)	Proved Plus Probable (mbbls)	Proved (mmcf)	Proved Plus Probable (mmcf)	Proved (mboe)	Proved Plus Probable (mboe)
December 31, 2005	286	371	78	102	926	1,712	10,648	14,608	3,065	4,621
Additions[1]	88	144	17	39	1,397	2,010	1,531	4,192	1,757	2,891
Technical revisions[2]	17	22	7	4	144	27	(234)	(570)	128	(43)
Acquisitions	0	0	0	0	0	0	0	0	0	0
Dispositions	(8)	(8)	0	0	0	0	(4,406)	(5,924)	(742)	(995)
Production	(30)	(30)	(18)	(18)	(260)	(260)	(1,588)	(1,588)	(572)	(572)
December 31, 2006	**353**	**499**	**84**	**128**	**2,207**	**3,489**	**5,951**	**10,719**	**3,636**	**5,902**

(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.

RESERVES AND NET PRESENT VALUE (FORECAST PRICES AND COSTS)

The following tables summarize Rock's remaining oil and natural gas reserve volumes along with the value of future net revenue utilizing GLJ's forecast pricing and cost estimates as at December 31, 2006.

Reserves

	Oil		NGL		Heavy Oil		Natural Gas	
Reserves Category	Gross (mbbls)	Net (mbbls)	Gross (mbbls)	Net (mbbls)	Gross (mbbls)	Net (mbbls)	Gross (mmcf)	Net (mmcf)
Proved								
Proved producing	371	315	101	72	2,180	1,788	4,909	3,790
Proved non-producing	42	38	18	12	106	84	2,250	1,910
Proved undeveloped	0	0	0	0	419	335	348	251
Total proved	413	353	119	84	2,705	2,207	7,507	5,951
Probable additional	175	145	63	44	1,594	1,282	6,084	4,768
Total proved plus probable	588	499	183	128	4,299	3,489	13,591	10,719

Note: Figures may not add due to rounding.

Net Present Value of Future Net Revenue

	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	78,425	67,396	59,563	53,638	48,959	70,150	60,789	54,048	48,909	44,829
Proved non-producing	12,887	10,303	8,588	7,345	6,395	8,729	6,839	5,601	4,715	4,044
Proved undeveloped	5,665	4,925	4,307	3,786	3,343	3,717	3,112	2,626	2,229	1,899
Total proved	96,977	82,624	72,457	64,769	58,697	82,596	70,740	62,276	55,853	50,773
Probable additional	60,052	43,397	33,231	26,839	21,486	40,801	29,124	21,982	17,718	13,744
Total proved plus probable	157,029	126,021	105,688	91,158	80,183	123,397	99,864	84,257	73,031	64,517

Note: Figures may not add due to rounding.

RESERVES AND NET PRESENT VALUE (CONSTANT PRICES AND COSTS)

The following tables summarize Rock's remaining oil and natural gas reserves along with the value of future net revenue utilizing GLJ's constant pricing and costs estimates. Pricing was based on benchmark reference prices posted at or near December 31, 2006 with adjustments for oil differential and natural gas heating values applied to arrive at a company average. Capital and operating costs were not inflated.

Reserves

	Oil		NGL		Heavy Oil		Natural Gas	
Reserves Category	Gross (mbbls)	Net (mbbls)	Gross (mbbls)	Net (mbbls)	Gross (mbbls)	Net (mbbls)	Gross (mmcf)	Net (mmcf)
Proved								
Proved producing	375	319	101	71	2,180	1,790	4,928	3,804
Proved non-producing	42	38	18	12	106	84	2,238	1,939
Proved undeveloped	0	0	0	0	419	335	348	254
Total proved	417	357	119	84	2,705	2,209	7,514	5,996
Probable additional	175	146	63	44	1,594	1,284	6,026	4,713
Total proved plus probable	592	503	182	128	4,299	3,493	13,540	10,709

Note: Figures may not add due to rounding.

Net Present Value of Future Net Revenue

	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	72,077	62,251	55,181	49,783	45,492	65,890	57,307	51,063	46,266	42,436
Proved non-producing	9,858	8,027	6,739	5,775	5,024	6,657	5,297	4,353	3,657	3,122
Proved undeveloped	5,131	4,447	3,875	3,393	2,983	3,365	2,796	2,340	1,968	1,659
Total proved	87,067	74,726	65,795	58,951	53,500	75,912	65,400	57,757	51,891	47,218
Probable additional	48,533	35,925	27,897	22,330	18,256	32,952	24,026	18,341	14,407	11,536
Total proved plus probable	135,600	110,651	93,693	81,281	71,756	108,864	89,425	76,098	66,298	58,753

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 Constant Prices and Costs evaluation and the Forecast Prices and Costs evaluation.

Summary of Pricing and Cost Rate Assumptions at December 31, 2006 – Constant Prices and Costs

Edmonton Par Oil Price 40° API (Cdn$/bbl)	AECO Gas Price (Cdn$/mcf)	NGL Edmonton Pentane (Cdn$/bbl)	NGL Edmonton Propane (Cdn$/bbl)	NGL Edmonton Butane (Cdn$/bbl)	NGL Ethane (Cdn$/bbl)	Exchange Rate (US$/Cdn$)
67.58	6.07	71.55	43.25	54.06	20.43	0.8581

Summary of Pricing and Cost Rate Assumptions at December 31, 2006 – Forecast Prices and Costs

	Oil				NGL				Natural Gas		
Year	WTI Cushing (US$/bbl)	Edmonton Reference Price ($/bbl)	Medium 29° API ($/bbl)	Hardisty Heavy 12° API ($/bbl)	Edmonton Propane ($/bbl)	Edmonton Butane ($/bbl)	Edmonton Pentane ($/bbl)	Ethane ($/bbl)	US$/Cdn$ AECO-C ($/mcf)	Exchange Rate	Cost Inflation Rate (%/year)
2007	62.00	70.25	61.25	39.25	45.00	56.25	71.75	24.25	7.20	0.87	2
2008	60.00	68.00	59.25	40.00	43.50	50.25	69.25	25.25	7.45	0.87	2
2009	58.00	65.75	57.25	39.75	42.00	48.75	67.00	26.25	7.75	0.87	2
2010	57.00	64.50	56.00	39.75	41.25	47.75	65.75	26.50	7.80	0.87	2
2011	57.00	64.50	56.00	40.25	41.25	47.75	65.75	26.50	7.85	0.87	2
2012	57.50	65.00	56.50	41.50	41.50	48.00	66.25	27.75	8.15	0.87	2
2013	58.50	66.25	57.75	42.50	42.50	49.00	67.50	28.25	8.30	0.87	2
2014	59.75	67.75	59.00	43.50	43.25	50.25	69.00	29.00	8.50	0.87	2
2015	61.00	69.00	60.00	44.25	44.25	51.00	70.50	29.50	8.70	0.87	2
2016	62.25	70.50	61.25	45.25	45.00	52.25	72.00	30.00	8.90	0.87	2
2017	63.50	71.75	62.50	46.00	46.00	53.00	73.25	30.75	9.10	0.87	2
2018+	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	0.87	2

FINDING, DEVELOPMENT AND ACQUISITION COSTS

The following table summarizes Rock's finding, development and acquisition costs for the years ended December 31, 2006 and 2005 and the nine months ended 2004, including future development costs. Due to the change in the Company's year-end in 2004 only nine-month data is shown for finding and development costs for 2004, given the availability of independent reserve information for that period.

Finding, Development and Acquisition Costs

	12 months ended Dec. 31, 2006	12 months ended Dec. 31, 2005	9 months ended Dec. 31, 2004	Period Cumulative Total
Oil and Natural Gas Operations:				
Proved finding and development costs				
Capital expenditures[1] ($000)	**$ 32,907**	$ 22,912	$ 5,876	$ 61,695
Future capital costs ($000)	**2,939**	962	1,174	5,075
Total capital ($000)	**$ 35,846**	$ 23,874	$ 7,050	$ 66,877
Reserve additions[2] (mboe)	**2,181**	1,188	294	6,663
Proved finding and development costs ($/boe)	**$ 16.44**	$ 20.10	$ 23.98	$ 18.23
Proved plus probable finding and development costs				
Capital expenditures[1] ($000)	**$ 32,907**	$ 22,912	$ 5,876	$ 61,695
Future capital costs ($000)	**7,986**	3,900	3,051	14,937
Total capital ($000)	**$ 40,893**	$ 26,812	$ 8,927	$ 76,739
Reserve additions[2] (mboe)	**3,624**	2,201	551	6,376
Proved plus probable finding and development costs ($/boe)	**$ 11.28**	$ 12.18	$ 16.20	$ 12.02
Acquisitions/Dispositions:				
Proved finding and development costs – Acquisitions (Dispositions)				
Capital expenditures[1] ($000)	**$ (30,878)**	$ 60,853	$ –	$ 29,975
Future capital costs ($000)	**(2,400)**	3,647	–	1,247
Total capital ($000)	**$ (33,278)**	$ 64,500	$ –	$ 31,222
Reserve additions (mboe)	**(1,042)**	2,397	–	1,355
Proved finding and development costs ($/boe)	**$ (31.94)**	$ 26.91	$ –	$ 23.04
Proved plus probable finding and development costs – Acquisitions (Dispositions)				
Capital expenditures[1] ($000)	**$ (30,878)**	$ 60,853	$ –	$ 29,975
Future capital costs ($000)	**(2,400)**	3,733	–	1,333
Total capital ($000)	**$ (33,278)**	$ 64,586	$ –	$ 31,308
Reserve additions (mboe)	**(1,406)**	3,154		
Proved plus probable finding and development costs ($/boe)	**$ (23.67)**	$ 20.48	$ –	$ 17.91
Total Activities:				
Proved finding and development costs				
Capital expenditures[1] ($000)	**$ 2,029**	$ 83,765	$ 5,876	$ 91,670
Future capital costs ($000)	**539**	4,609	1,174	6,322
Total capital ($000)	**$ 2,568**	$ 88,374	$ 7,050	$ 98,099
Reserve additions[3] (mboe)	**1,279**	3,620	273	5,172
Total Proved finding and development costs ($/boe)	**$ 2.01**	$ 24.41	$ 25.82	$ 18.95
Proved plus probable finding and development costs				
Capital expenditures[1] ($000)	**$ 2,029**	$ 83,765	$ 5,876	$ 91,670
Future capital costs ($000)	**5,586**	7,633	3,051	16,270
Total capital ($000)	**$ 7,615**	$ 91,398	$ 8,927	$ 108,047
Reserve additions[3] (mboe)	**2,153**	5,284	422	7,859
Total Proved plus probable finding and development costs ($/boe)	**$ 3.54**	$ 17.30	$ 21.15	$ 13.73

[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 and development 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. Finding and development costs on operations improved in 2006 compared to 2005 and 2004 primarily as Rock's grassroots exploration and development program gained momentum. Capital costs on operations for 2005 and 2004 included a relatively high land and seismic component, 23 percent and 48 percent of expenditures respectively, which increased finding and development costs.

Rock's 2007 capital budget has approximately 25 percent of the spending allocated to land and seismic as the Company continues to build its grassroots program, particularly in the West Central Alberta core area. Finding and development costs on the acquired properties are based on the reserve evaluation as at December 31, 2005 and were increased by the amount of production from the closing date to December 31, 2005 to provide an estimate of the reserves purchased. Finding and development 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. Finding and development costs for total activities include operations, acquisitions, dispositions and reserve revisions.

LAND HOLDINGS

The following table summarizes Rock's land holdings as at December 31, 2006 and 2005:

(acres)		December 31, 2006	December 31, 2005	Change
Developed	– Gross	**63,085**	79,188	(20)%
	– Net	**23,566**	31,378	(25)%
Undeveloped	– Gross	**76,030**	79,666	(5)%
	– Net	**39,429**	36,898	7%
Total	– Gross	**139,115**	158,854	(12)%
	– Net	**62,995**	68,276	(8)%

NET ASSET VALUE

The following table summarizes Rock's net asset value and net asset value per share as at December 31, 2006 and December 31, 2005:

($000 except number of shares and net asset value per share)	December 31, 2006	December 31, 2005	Change
Proved plus probable reserves[1]	**105,688**	87,315	21%
Undeveloped land[2]	**8,220**	8,448	(3)%
Seismic[3]	**3,550**	2,617	36%
Working capital including debt	**(12,580)**	(24,442)	49%
Option proceeds	**7,405**	5,053	47%
Net asset value (Diluted)	**112,283**	78,991	42%
Diluted shares (000)	**21,405**	20,758	3%
Net asset value per share	**$ 5.25**	$ 3.81	38%

(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 2006 and 2005 forecast pricing and costs estimates and using a discount rate of 10 percent.

(2) 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.

(3) Seismic value is based on actual cost of seismic acquired or purchased.

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:

	2007	2008	2009	2010	2011
Office premise leases	$ 676	$ 895	$ 828	$ 828	$ 828
Demand bank loan(1)	$ 10,965				

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

OUTSTANDING SHARE DATA

At December 31, 2006 and to date, Rock had 19,637,321 common shares outstanding. At December 31, 2006 the Company had 1,767,277 stock options outstanding with an average exercise price of $4.19 per share.

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 Chief Executive Officer and the Chief Financial Officer have evaluated the effectiveness of the disclosure controls and procedures as at December 31, 2006 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, 2006. 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

There has been no change in accounting policies since the Company's last fiscal year-end.

NEW ACCOUNTING PRONOUNCEMENTS

Comprehensive Income

The Canadian Institute of Chartered Accountants (CICA) issued CICA Handbook section 1530, Comprehensive Income. The section is effective for fiscal years beginning on or after October 1, 2006. It describes how to report and disclose comprehensive income and its components. An integral part of the accounting standards on recognition and measurement of financial instruments is the ability to present certain gains and losses outside net income, in other comprehensive income. This standard requires that a company present comprehensive income and its components in a financial statement displayed with the same prominence as other financial statements that constitute a complete set of financial statements, in both annual and interim financial statements.

The CICA also made changes to CICA Handbook section 3250, Surplus, and reissued it as section 3251, Equity. The section is also effective for fiscal years beginning on or after October 1, 2006. The changes in how to report and disclose equity and changes in equity are consistent with the new requirements of section 1530, Comprehensive Income.

Rock will adopt this section effective January 1, 2007 but the Company does not expect this section to have a material impact on its consolidated financial statements.

Financial Instruments – Recognition and Measurement

The CICA issued CICA Handbook section 3855, Financial Instruments – Recognition and Measurement. The section is effective for fiscal years beginning on or after October 1, 2006. It describes the standards for recognizing and measuring financial assets, financial liabilities and non-financial derivatives. This section requires that all financial assets be measured at fair value, with some exceptions; all financial liabilities be measured at fair value if they are derivatives or classified as held for trading purposes (other financial liabilities are measured at their carrying value); and all derivative financial instruments be measured at fair value, even when they are part of a hedging relationship.

Rock will adopt this section effective January 1, 2007 but does not expect this section to have a material impact on its consolidated financial statements.

Hedges

The CICA issued CICA Handbook section 3865, Hedges. The section is effective for fiscal years beginning on or after October 1, 2006, and describes when and how hedge accounting can be used. Hedging is an activity used by a company to change an exposure to one or more risks by creating an offset between changes in the fair value of a hedged item and a hedging item; changes in the cash flows attributable to a hedged item and a hedging item; or changes resulting from a risk exposure relating to a hedged item and a hedging item. Hedge accounting ensures that all gains, losses, revenues and expenses from the derivative and the item it hedges are recorded in the income statement in the same period.

Rock will adopt this section effective January 1, 2007 but does not expect this section to have a material impact on its consolidated financial statements.

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 judgments 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 judgment 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. Judgments 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 were 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 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 high activity levels the industry has been experiencing, 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.

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 1800, 700 - 9th Avenue S.W., Calgary, Alberta, T2P 3V4.

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 judgment, 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.

[Signed] "Allen J. Bey"

Allen J. Bey
President and Chief Executive Officer

[Signed] "Peter D. Scott"

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

March 15, 2007

AUDITORS' REPORT

To the Shareholders of Rock Energy Inc.:

We have audited the consolidated balance sheets of Rock Energy Inc. as at December 31, 2006 and 2005 and the consolidated statements of operations 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, 2006 and 2005 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

[Signed] "KPMG LLP"

KPMG LLP

Chartered Accountants
Calgary, Canada

March 15, 2007

CONSOLIDATED BALANCE SHEETS

(000s of dollars) As at	December 31, 2006	December 31, 2005
Assets		
Current assets		
Cash and cash equivalents	$ –	$ 145
Accounts receivable	4,753	7,093
Prepaid expenses	532	385
	5,285	7,623
Property, plant and equipment (note 4)	97,229	95,271
Accumulated depletion and depreciation	(22,882)	(8,893)
	74,347	86,378
Goodwill	5,748	5,602
	$ 85,380	$ 99,603
Liabilities and Shareholders' Equity		
Current liabilities		
Accounts payable and accrued liabilities	$ 6,900	$ 9,090
Bank debt (note 5)	10,965	22,976
	17,865	32,066
Future tax liability (note 9)	4,942	5,204
Asset retirement obligation (note 6)	2,094	2,115
Shareholders' equity		
Share capital (note 7)	57,326	57,369
Contributed surplus (note 8)	1,641	453
Retained earnings	1,512	2,396
	60,479	60,218
Commitments (note 11)		
Subsequent event (note 12)		
	$ 85,380	$ 99,603

See accompanying notes to consolidated financial statements.

Approved by the Board:

[Signed] "Stuart G. Clark"

Stuart G. Clark
Director

[Signed] "Allen J. Bey"

Allen J. Bey
Director

CONSOLIDATED STATEMEMENTS OF **OPERATIONS** AND **RETAINED EARNINGS**

(000s of dollars, except per share amounts) Years ended	December 31, 2006	December 31, 2005
Revenues:		
Oil and natural gas revenue	**$ 33,156**	$ 22,873
Royalties, net of Alberta Royalty Tax Credit	**(6,881)**	(5,027)
Other income	**198**	317
	26,473	18,163
Expenses:		
General and administrative	**2,278**	1,411
Operating	**9,255**	4,745
Interest	**924**	457
Stock-based compensation (note 8)	**1,188**	485
Depletion, depreciation, and accretion	**14,118**	8,287
	27,763	15,385
Income (loss) before income taxes	**(1,290)**	2,778
Income taxes		
Current (note 9)	**45**	73
Future income taxes (reduction) (note 9)	**(451)**	1,196
Net income (loss) for the year	**(884)**	1,509
Retained earnings, beginning of year	**2,396**	887
Retained earnings, end of year	**$ 1,512**	$ 2,396
Diluted and basic net income (loss) per share (note 7)	**$ (0.05)**	$ 0.10

See accompanying notes to consolidated financial statements.

CONSOLIDATED STATEMEMENTS OF CASH FLOW

(000s of dollars) Years ended	December 31, 2006	December 31, 2005
Cash provided by (used in):		
Operating:		
Net income (loss) for the year	**$ (884)**	$ 1,509
Add: Non-cash items:		
Depletion, depreciation, and accretion	**14,118**	8,287
Actual abandonment costs	**(104)**	(44)
Stock-based compensation	**1,188**	485
Future income taxes (reduction)	**(451)**	1,196
	13,867	11,433
Changes in non-cash working capital	**2,571**	(4,319)
	16,438	7,114
Financing:		
Issuance of common shares	**–**	217
Bank debt	**(12,011)**	22,976
Repurchase of stock options	**–**	(185)
	(12,011)	23,008
Investing:		
Property, plant and equipment	**(32,879)**	(23,644)
Acquisition of property, plant and equipment (note 3)	**–**	(23,880)
Disposition of property, plant and equipment	**30,874**	–
Changes in non-cash working capital	**(2,567)**	8,915
	(4,572)	(38,609)
Decrease in cash and cash equivalents	**(145)**	(8,487)
Cash and cash equivalents, beginning of year	**145**	8,632
Cash and cash equivalents, end of year	**$ –**	$ 145
Interest and taxes paid and received:		
Interest paid	**960**	428
Interest received	**32**	42
Taxes paid	**$ 25**	$ 57

See accompanying notes to consolidated financial statements.

NOTES TO CONSOLIDATED Financial Statements

Years ended December 31, 2006 and 2005

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 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. The Company follows the Canadian accounting standard relating to stock-based compensation and other stock-based payments as it applies to other stock-based compensation granted to employees, officers and directors. Under this standard, future 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 and the amounts used for ceiling test calculations are based on estimates of reserves, future costs and timing. 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. Acquisition of ELM/Optimum/Qwest

On March 14, 2005 the Company agreed to acquire, in two separate closings from 14 different entities (six private companies and eight drilling fund partnerships), petroleum and natural gas properties mainly through their various subsidiary companies. The transactions have been accounted for using the purchase method with the results of operations for each transaction included in the financial statements from the date of acquisition.

The first closing of the ELM/Optimum/Qwest properties occurred on April 7, 2005. The Company purchased all of the outstanding shares of 1143734 Alberta Ltd. and assets were purchased directly from three private entities and four drilling fund partnerships. The final purchase price equation is as follows:

($000)		
Property, plant and equipment	$	16,483
Note payable*		(309)
Asset retirement obligation		(373)
	$	15,801
Consideration provided:		
Cash	$	4,575
Common shares (3,091,483)		10,944
Transaction costs		282
	$	15,801

* Paid to vendors on final adjustments

The second closing of the ELM/Optimum/Qwest properties occurred on June 17, 2005. The Company purchased all of the outstanding shares of 1156168 Alberta Ltd., 1159203 Alberta Ltd. and 1140511 Alberta Ltd. The purchase price equation is as follows:

($000)		
Property, plant and equipment	$	45,490
Note receivable*		148
Goodwill		4,593
Future income taxes		(4,593)
Asset retirement obligation		(1,007)
	$	44,631
Consideration provided:		
Cash	$	18,504
Common shares (7,234,005)		25,609
Transaction costs		518
	$	44,631

* Paid by vendors on final adjustments

The purchase price allocations for both transactions were initially based on estimates of the fair values of the assets and liabilities as of the closing date, purchase price adjustments, transaction costs and holdback amounts.

4. Property, Plant and Equipment

($000)	December 31, 2006	December 31, 2005
Petroleum and natural gas properties	$ 96,887	$ 95,160
Other assets	342	111
	97,229	95,271
Accumulated depletion and depreciation	(22,882)	(8,893)
	$ 74,347	$ 86,378

In the third quarter of 2006, the Company disposed of four non-operated producing properties for total proceeds of approximately $30.9 million. The properties disposed of included Wild River, Highland/Hudson and Chestermere. As the change in the depletion rate was less than 20 percent, no gain has been booked into the financial statements.

At December 31, 2006, petroleum and natural gas properties included $8,220, (December 31, 2005 – $6,265 of unproved property costs which have been excluded from the depletable base.

During the year ended December 31, 2006, $1,627 (year ended December 31, 2005 – $865) of administrative costs relating to exploration and development activities were capitalized as part of property, plant and equipment.

At December 31, 2006, 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 AECO-C Spot Price (Cdn$/mmbtu)	Heavy Oil at Hardisty (12° API) (Cdn$/bbl)	Currency Exchange Rate (US$/Cdn$)
2007	62.00	70.25	7.20	39.25	0.87
2008	60.00	68.00	7.45	40.00	0.87
2009	58.00	65.75	7.75	39.75	0.87
2010	57.00	64.50	7.80	39.75	0.87
2011	57.00	64.50	7.85	40.25	0.87
2012	57.50	65.00	8.15	41.50	0.87
2013	58.50	66.25	8.30	42.50	0.87
2014	59.75	67.75	8.50	43.50	0.87
2015	61.00	69.00	8.70	44.25	0.87
2016	62.25	70.50	8.90	45.25	0.87
2017	63.50	71.75	9.10	46.00	0.87
Thereafter (escalation)	2.0%/yr	2.0%/yr	2.0%/yr	2.0%/yr	0.87

5. Bank Debt

At December 31, 2006 the Company has 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 current limit under the facility is $18 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. The facility also bears a standby charge for undrawn amounts. The facility was replaced in March 2007 (see note 12, Subsequent Event).

6. 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, 2006 is approximately $3,666 (December 31, 2005 – $3,385), which will be incurred between 2007 and 2019. 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.

A reconciliation of the asset retirement obligations is provided below:

	December 31, 2006	December 31, 2005
Balance, beginning of year	**$ 2,115**	$ 500
Liabilities incurred/acquired during year	**413**	1,583
Dispositions	**(459)**	–
Accretion	**129**	76
Actual retirement costs	**(104)**	(44)
Balance, end of year	**$ 2,094**	$ 2,115

7. 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, 2004	9,259,453	$ 21,276
Redemption (i)	(448)	(2)
Future tax effect of flow-through share renouncements (ii)		(723)
Issued for property acquisitions	10,325,488	36,552
Issued for flow-through shares (iii)	22,263	115
Issued for stock options exercised	30,565	151
Issued and outstanding as at December 31, 2005	19,637,321	$ 57,369
Future tax effect of flow-through share renouncements (iii)	–	(43)
Issued and outstanding as at December 31, 2006	**19,637,321**	**$ 57,326**

(i) In accordance with the terms of the 30-for-1 share consolidation, shareholders holding 1,000 or fewer pre-consolidated common shares redeemed their shares for cash based on the value of $0.1129 per pre-consolidated share.

(ii) The Company has renounced resource expenditures on flow-through shares issued by predecessor companies. At March 31, 2004, the Company was committed to spending $1.8 million on drilling and exploration activities on or before January 31, 2005 to satisfy flow-through share commitments. At December 31, 2004, all required expenditures had been made and the Company completed the renouncements in February 2005.

(iii) 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.

As at December 31, 2006 and 2005 no preference shares were outstanding.

(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, 2006 and December 31, 2005 and changes during the year ended on those dates:

	December 31, 2006		December 31, 2005	
	Options	**Weighted-Average Exercise Price ($)**	Options	Weighted-Average Exercise Price ($)
Outstanding, beginning of year	**1,120,332**	**$ 4.51**	532,387	$ 3.49
Granted	**677,779**	**$ 3.66**	777,944	$ 4.95
Exercised	**-**	**-**	(135,629)	$ 3.39
Forfeited	**-**	**-**	(54,370)	$ 3.58
Expired	**(30,834)**	**$ 3.87**	–	–
Outstanding, end of year	**1,767,277**	**$ 4.19**	1,120,332	$ 4.51

Options outstanding and exercisable under the stock option plan are summarized below as at December 31, 2006:

	Outstanding Options			Exercisable Options	
	Number of Options	Weighted-Average Exercise Price	Weighted-Average Years to Expiry	Number of Options	Weighted-Average Exercise Price ($)
$ 3.15 - $ 3.90	754,333	$ 3.30	1.83	155,777	$ 3.47
$ 4.00 - $ 5.11	1,012,944	$ 4.86	1.76	217,667	$ 4.93
	1,767,277	$ 4.19	1.79	373,444	$ 4.32

(D) PER SHARE AMOUNTS

The weighted average number of common shares outstanding during the year ended December 31, 2006 of 19,637,321 (year ended December 31, 2005 - 15,436,835) 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, 2006. As at December 31, 2006, an additional 17,660 (December 31, 2005 – 64,127) common shares were used to calculate diluted earnings per share.

8. 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, 2006 was estimated to be $976 (year ended December 31, 2005 – $1,658) as at the grant date using the Black-Scholes option pricing model and the following assumptions:

Risk-free interest rate	4.00% - 6.00%
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, 2006	December 31, 2005
Balance, beginning of year	**$ 453**	$ 202
Stock-based compensation expense	**1,188**	485
Net benefit on options exercised[1]	**-**	(234)
Balance, end of year	**$ 1,641**	$ 453

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

9. 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 33.7 percent (December 31, 2005 – 37.62 percent). The principal reasons for differences between such "expected" income tax expense and the amount actually recorded are as follows:

	December 31, 2006	December 31, 2005
Net income before income taxes	**$ (1,290)**	$ 2,778
Statutory income tax rate	**33.7%**	37.62%
Expected income taxes	**$ (435)**	$ 1,045
Add (deduct):		
Stock-based compensation	**400**	182
Non-deductible Crown charges	**330**	1,038
Change in enacted rates	**(311)**	-
Other	**180**	19
Resource allowance	**(615)**	(888)
Acquisition	**-**	12,133
Change in valuation allowance	**-**	(12,333)
Provision for income taxes	**$ (451)**	$ 1,196
Capital tax	**45**	73
Provision for (recovery of) income taxes	**$ (406)**	$ 1,269

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, 2006	December 31, 2005
Loss carry-forwards	**$ 4,941**	$ 9,097
Property, plant and equipment	**(6,218)**	(11,542)
Non-coterminous year-ends	**(3,859)**	(3,049)
Share issuance costs	**263**	360
Asset retirement obligation	**649**	719
Calculated future income tax liability	**(4,224)**	(4,415)
Valuation allowance	**(718)**	(789)
Future income taxes (liability)	**$ (4,942)**	$ (5,204)

At December 31, 2006, Rock and its subsidiary have tax pools aggregating $69.0 million prior to the allocation of deferred partnership income and $55.2 million (December 31, 2005 - $65.5 million) after the allocation of deferred partnership income. The non-capital losses prior to the allocation of deferred partnership income expire as follows:

2011	$ 479
2026	13,656
	$ 14,135

10. 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.

11. Commitments

Obligations with a fixed term are as follows:

	2007	2008	2009	2010	2011
Office premise leases	$ 676	$ 895	$ 828	$ 828	$ 828

12. Subsequent Event

Subsequent to year-end the Company entered into a new demand operating facility with a different Canadian chartered bank. The new facility has a borrowing limit of $23 million, up from the current limit of $18 million. The new loan is based on the Company's 2005 reserve report by GLJ Petroleum Consultants Ltd. (GLJ) and internal estimates at September 30, 2006. The new facility will be reviewed before April 30, 2007 utilizing the current GLJ reserve report as at December 31, 2006.

CORPORATE INFORMATION

BOARD OF DIRECTORS

Stuart G. Clark
Chairman of the Board
Independent Businessman
Calgary, Alberta

Allen J. Bey
President and Chief Executive Officer
Rock Energy Inc.
Calgary, Alberta

Matthew J. Brister
President and Chief Executive Officer
Storm Ventures International Inc.
Calgary, Alberta

Peter V. Malowany
President
Morgas Ltd.
Calgary, Alberta

James K. Wilson
Vice President, Finance and
Chief Financial Officer
Grizzly Resources Ltd.
Calgary, Alberta

OFFICERS

Allen J. Bey
President and Chief Executive Officer

A.C. (Sandy) Brown
Vice President, Exploration

Sean E. Moore
Vice President, Production

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

Grant A. Zawalsky
Corporate Secretary

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BANK

National Bank of Canada

ENGINEERING CONSULTANT

GLJ Petroleum Consultants Ltd.

SOLICITORS

Burnet, Duckworth & Palmer LLP

STOCK EXCHANGE LISTING

TSX
Stock Symbol: RE

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TSX: RE

File No. 82-34785

rockenergy INC.

Annual Information Form

Year Ended December 31, 2006

March 15, 2007

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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
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 February 27, 2007 evaluating the crude oil, natural gas liquids and natural gas reserves of the Corporation as at December 31, 2006;

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

(a) in relation to the Corporation's interest in production and reserves, its "Corporation gross reserves", which are the Corporation's interest (operating and non-operating) share before deduction of royalties and without including any royalty interest of the Corporation;

(b) in relation to wells, the total number of wells in which the Corporation has an interest; and

(c) in relation to properties, the total area of properties in which the Corporation has an interest; and

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

(d) in relation to the Corporation's interest in production and reserves, the Corporation's interest (operating and non-operating) share after deduction of royalties obligations, plus the Corporation's royalty interest in production or reserves;

(e) in relation to wells, the number of wells obtained by aggregating the Corporation's working interest in each of its gross wells; and

(f) in relation to the Corporation's interest in a property, the total area in which the Corporation has an interest multiplied by the working interest owned by the Corporation;

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

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

ROCK ENERGY INC.

The Corporation

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

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

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

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

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

Corporate Strategy

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

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

Subsidiaries

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

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

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

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

DESCRIPTION OF CAPITAL STRUCTURE

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

Common Shares

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

Preferred Shares

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

The following sets forth information in respect of securities authorized for issuance under the Corporation's equity compensation plan as at December 31, 2006.

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	1,767,276	$4.19	196,456(1)
Equity compensation plans not approved by securityholders	-	-	-
Total	1,767,276	$4.19	196,456(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, 2006) were sold in the transactions (collectively the "Dispositions"). The proceeds of $30.8 million were used to repay bank indebtedness.

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.

RECENT DEVELOPMENTS

The Corporation has had no material recent developments since December 31, 2006.

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 $2.0 million for the year ended December 31, 2006 which included $30.8 million received from the Dispositions, $0.1 million for office equipment and $32.7 million on Rock's exploration and development operations primarily in the Plains and West Central core areas. Of the $32.7 million noted above, 17% was spent on acquiring land ($4.8 million) and seismic ($0.9 million). Rock drilled 26 (26 net) wells in its Plains core area, 7 (2.2 net) non-operated wells mostly in the West Central core area, and re-completed 9 (6.1 net) wells in 2006, which accounted for 76% of spending or $25.1 million. Of these wells, 25 (25.0 net) are successful heavy oil wells, 4 (1.4 net) are successful gas wells, 2 (0.7 net) are successful light oil wells and 2 (1.2 net) were dry. All of the successful heavy and light oil wells were completed and equipped in 2006, except for 4 (4.0 net) heavy oil wells drilled late in the year which were brought on production in the first quarter of 2007. Of the gas wells 2 (0.3 net) were brought on production during 2006 and the remaining 2 (1.1 net) wells are expected to be tied in during the fourth quarter of 2007, when third party facilities in the area are expanded. Of the re-completion operations, 7 (5.4 net) were successful which resulted in 3 (3.0 net) heavy oil wells, 1 (1.0 net) light oil well, 3 (1.4 net) gas wells and 2 (0.7 net) abandoned operations. All successful re-completions were brought on production except for 1 (0.8 net) gas well, which is waiting on the same facility expansion discussed above and is expected to be on in the fourth quarter of 2007. Rock capitalizes certain salary and related costs associated with exploration and development which accounted for 5% ($1.6 million) of exploration and development capital spending for 2006.

Rock's Board of Director's has approved a $20 million capital budget for 2007 directed primarily at the Plains and West Central core areas. This budget contemplates drilling 16 to 22 wells for approximately $14.5 million, acquiring land and seismic for $4 million, capitalized administrative costs of $1.5 million and leasehold office space improvements of $0.5 million for the Company's new office space. The majority of the drilling is likely expected to commence after spring break-up. The drilling program is on lands that are currently owned and are seismically supported and will be a mix of exploration and development wells targeting both oil and gas. Included in the drilling costs are the estimated cost of tie-ins and well site facilities required to bring production on stream. Under this program, new production is expected to come on stream from two (typically oil wells) to six months (typically gas wells) after drilling has been completed. The budget is split almost equally between the Plains and West Central core areas. Rock currently has approximately 80 drilling opportunities in various stages of readiness identified in the Plains (50 locations) and West Central (30 locations) core areas.

Principal Properties

The following is a description of the Corporation's oil and natural gas properties as at December 31, 2006. Unless otherwise specified, gross and net acres and well count information are as at December 31, 2006.

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, 3 (2.0 net) producing gas wells and 1 (0.8 net) shut-in gas well. No disposal or injection wells are located on the property. Production is initially processed through Rock's 100% owned facility which is located on these lands. The facility processes the oil in order to meet pipeline specifications and is then trucked to a third party terminal for sale. The facility also meters and compresses Rock's operated natural gas production which is tied-in to a third party processing plant for ultimate sale. Rock operates all the production (except 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. In September 2006 Rock recompleted a well in the Basal Quartz formation.

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

Rock owns 21,480 (21,357 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 30 (30.0 net) producing heavy oil wells, 1 (1.0 net) producing gas well 2 (2.0 net) standing gas wells, 10 (10.0 net) shut-in wells and no disposal wells. The heavy oil wells were drilled in 2004, 2005 and 2006 with most of the production coming on since late 2005. These wells are primarily producing from the Sparky formation. Production is processed at a 100% owned well site batteries and then trucked to a third party terminal for sale. Gas production is tied into a 100% owned gathering lines which tie in to third party pipelines and processing facilities where the gas is sold.

Musreau, Alberta

The Corporation's interests in the Musreau area includes 9 (1.1 net) producing natural gas wells, 3(1.9 net) natural gas wells to be tied-in, and no shut-in, producing oil or disposal wells. The gas wells were drilled in the second half of 2004, 2005 and 2006 and produce from the Fahler, Cadomin and Bluesky formations. The wells are non-operated, except for 2 (1.8 net) gas wells, which will be tied in once third party facilities are expanded in the area. Gas is gathered and processed at a third party plant in the area. The Corporation owns 8,640 (1,714 net) undeveloped acres of land in the area. Management expects additional drilling in 2007.

Elmworth/Wapiti, Alberta

The Corporation's interest in the Elmworth/Wapiti area includes 7 (1.8 net) natural gas wells and no oil wells, shut-in wells or disposal wells. Production comes from the Notikewin, Falher, Cadomin and Gething formations and is non-operated. Production is processed at third party facilities. The Corporation owns 5,120 (1,808 net) undeveloped acres of land in the area.

Niton, Alberta

The Corporation's interest in the Niton area includes 6 (2.3 net) oil wells and no natural gas, 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 2,883 (1,108 net) undeveloped 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 February 27, 2007. The effective date of the Statement is December 31, 2006 and the preparation date of the Statement is February 15, 2007.

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, 2006 contained in the GLJ Report. The Reserves Data summarizes the oil, liquids and natural gas reserves of the Corporation and the net present values of future net revenue for these reserves using constant prices and costs and forecast prices and costs. The GLJ Report has been prepared in accordance with the standards contained in the COGE Handbook and the reserve definitions contained in NI 51-101. Additional information not required by NI 51-101 has been presented to provide continuity and additional information which we believe is important to the readers of this information. The Company engaged GLJ to provide an evaluation of proved and proved plus probable reserves and no attempt was made to evaluate possible reserves. All of Rock's reserves are in Canada and, specifically, in the provinces of Alberta, British Columbia and Saskatchewan.

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

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

Reserves Data (Constant Prices and Costs)

SUMMARY OF OIL AND GAS RESERVES
AND NET PRESENT VALUES OF FUTURE NET REVENUE
as of December 31, 2006
CONSTANT PRICES AND COSTS

	RESERVES							
	LIGHT AND MEDIUM OIL		HEAVY OIL		NATURAL GAS		NATURAL GAS LIQUIDS	
RESERVES CATEGORY	Gross (Mbbl)	Net (Mbbl)	Gross (Mbbl)	Net (Mbbl)	Gross (MMcf)	Net (MMcf)	Gross (Mbbl)	Net (Mbbl)
PROVED								
Producing	375	319	2,180	1,790	4,928	3,804	101	71
Developed Non-Producing	42	38	106	84	2,238	1,939	18	12
Undeveloped	0	0	419	335	348	254	0	0
TOTAL PROVED	417	357	2,705	2,209	7,514	5,996	119	84
PROBABLE	175	146	1,594	1,284	6,026	4,713	63	44
TOTAL PROVED PLUS PROBABLE	592	503	4,299	3,493	13,540	10,709	182	128

NET PRESENT VALUES OF FUTURE NET REVENUE

RESERVES CATEGORY	BEFORE INCOME TAXES DISCOUNTED AT (%/year) 0 (M$)	5 (M$)	10 (M$)	15 (M$)	20 (M$)	AFTER INCOME TAXES DISCOUNTED AT (%/year) 0 (M$)	5 (M$)	10 (M$)	15 (M$)	20 (M$)
PROVED										
Producing	72,077	62,251	55,181	49,783	45,492	65,890	57,307	51,063	46,266	42,436
Developed Non-Producing	9,858	8,027	6,739	5,775	5,024	6,657	5,297	4,353	3,657	3,122
Undeveloped	5,131	4,447	3,875	3,393	2,983	3,365	2,796	2,340	1,968	1,659
TOTAL PROVED	87,067	74,726	65,795	58,951	53,500	75,912	65,400	57,757	51,891	47,218
PROBABLE	48,533	35,925	27,897	22,330	18,256	32,952	24,026	18,341	14,407	11,536
TOTAL PROVED PLUS PROBABLE	135,600	110,651	93,693	81;281	71,756	108,864	89,425	76,098	66,298	58,753

TOTAL FUTURE NET REVENUE
(UNDISCOUNTED)
as of December 31, 2006
CONSTANT PRICES AND COSTS

RESERVES CATEGORY	REVENUE (M$)	ROYALTIES (M$)	OPERATING COSTS (M$)	DEVELOPMENT COSTS (M$)	WELL ABANDONMENT COSTS (M$)	FUTURE NET REVENUE BEFORE INCOME TAXES (M$)	INCOME TAXES (M$)	FUTURE NET REVENUE AFTER INCOME TAXES (M$)
Proved Producing Reserves	141,926	27,012	40,566	378	1,892	72,077	6,187	65,890
Proved Reserves	180,984	33,558	51,162	6,767	2,430	87,067	11,155	75,912
Proved Plus Probable Reserves	291,926	55,752	81,487	16,220	2,867	135,600	26,736	108,864

FUTURE NET REVENUE
BY PRODUCTION GROUP
as of December 31, 2006
CONSTANT PRICES AND COSTS

RESERVES CATEGORY	PRODUCTION GROUP	FUTURE NET REVENUE BEFORE INCOME TAXES (discounted at 10%/year) (M$)
Proved Producing Reserves	Light and Medium Crude Oil (including solution gas and other by-products)	8,758
	Heavy Crude Oil	32,054
	Natural Gas	14,370
	Other Company Revenue	0
Proved Reserves	Light and Medium Crude Oil (including solution gas and other by-products)	8,867
	Heavy Crude Oil	37,374
	Natural Gas	19,554
	Other Company Revenue	0
Proved Plus Probable Reserves	Light and Medium Crude Oil (including solution gas and other by-products)	11,957
	Heavy Crude Oil	53,752
	Natural Gas	27,983
	Other Company Revenue	0

Reserves Data (Forecast Prices and Costs)

SUMMARY OF OIL AND GAS RESERVES
AND NET PRESENT VALUES OF FUTURE NET REVENUE
as of December 31, 2006
FORECAST PRICES AND COSTS

	RESERVES							
	LIGHT AND MEDIUM OIL		HEAVY OIL		NATURAL GAS		NATURAL GAS LIQUIDS	
RESERVES CATEGORY	Gross (Mbbl)	Net (Mbbl)	Gross (Mbbl)	Net (Mbbl)	Gross (MMcf)	Net (MMcf)	Gross (Mbbl)	Net (Mbbl)
PROVED								
Developed Producing	371	315	2,180	1,788	4,909	3,790	101	72
Developed Non-producing	42	38	106	84	2,250	1,910	18	12
Undeveloped	0	0	419	335	348	251	0	0
TOTAL PROVED	413	353	2,705	2,207	7,507	5,951	119	84
PROBABLE	175	145	1,594	1,282	6,084	4,768	63	44
TOTAL PROVED PLUS PROBABLE	588	499	4,299	3,489	13,591	10,719	183	128

NET PRESENT VALUES OF FUTURE NET REVENUE

RESERVES CATEGORY	BEFORE INCOME TAXES DISCOUNTED AT (%/year) 0 (M$)	5 (M$)	10 (M$)	15 (M$)	20 (M$)	AFTER INCOME TAXES DISCOUNTED AT (%/year) 0 (M$)	5 (M$)	10 (M$)	15 (M$)	20 (M$)
PROVED										
Developed Producing	78,425	67,396	59,563	53,638	48,959	70,150	60,789	54,048	48,909	44,829
Developed Non-producing	12,887	10,303	8,588	7,345	6,395	8,729	6,839	5,601	4,715	4,044
Undeveloped	5,665	4,925	4,307	3,786	3,343	3,717	3,112	2,626	2,229	1,899
TOTAL PROVED	96,977	82,624	72,457	64,769	58,697	82,596	70,740	62,276	55,853	50,773
PROBABLE	60,052	43,397	33,231	26,389	21,486	40,801	29,124	21,982	17,178	13,744
TOTAL PROVED PLUS PROBABLE	157,029	126,021	105,688	91,158	80,183	123,397	99,864	84,257	73,031	64,517

TOTAL FUTURE NET REVENUE
(UNDISCOUNTED)
as of December 31, 2006
FORECAST PRICES AND COSTS

RESERVES CATEGORY	REVENUE (M$)	ROYALTIES (M$)	OPERATING COSTS (M$)	DEVELOPMENT COSTS (M$)	WELL ABANDONMENT COSTS (M$)	FUTURE NET REVENUE BEFORE INCOME TAXES (M$)	INCOME TAXES (M$)	FUTURE NET REVENUE AFTER INCOME TAXES (M$)
Proved Producing Reserves	154,463	29,565	43,815	378	2,280	78,425	8,275	70,150
Proved Reserves	199,587	37,422	55,479	6,805	2,903	96,977	14,381	82,596
Proved Plus Probable Reserves	331,779	63,567	91,232	16,317	3,634	157,029	33,632	123,397

FUTURE NET REVENUE
BY PRODUCTION GROUP
as of December 31, 2006
FORECAST PRICES AND COSTS

RESERVES CATEGORY	PRODUCTION GROUP	FUTURE NET REVENUE BEFORE INCOME TAXES (discounted at 10%/year) (M$)
Proved Producing Reserves	Light and Medium Crude Oil (including solution gas and other by-products)	8,878
	Heavy Oil	32,395
	Natural Gas	17,570
	Other Company Revenue	0
Proved Reserves	Light and Medium Crude Oil (including solution gas and other by-products)	9,002
	Heavy Oil	38,775
	Natural Gas	24,680
	Other Company Revenue	0
Proved Plus Probable Reserves	Light and Medium Crude Oil (including solution gas and other by-products)	12,163
	Heavy Oil	56,013
	Natural Gas	37,512
	Other Company Revenue	0

Notes to Reserves Data Tables:

1. Columns may not add due to rounding.

2. The crude oil, natural gas liquids and natural gas reserve estimates presented in the GLJ Report are based on the definitions and guidelines contained in the COGE Handbook. A summary of those definitions are set forth below.

   Reserve Categories

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

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

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

   (a) **Proved reserves** are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.

   (b) **Probable reserves** are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves.

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

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

(c) **Developed reserves** are those reserves that are expected to be recovered from existing wells and installed facilities or, if facilities have not been installed, that would involve a low expenditure (for example, when compared to the cost of drilling a well) to put the reserves on production. The developed category may be subdivided into producing and non-producing.

(i) **Developed producing reserves** are those reserves that are expected to be recovered from completion intervals open at the time of the estimate. These reserves may be currently producing or, if shut-in, they must have previously been on production, and the date of resumption of production must be known with reasonable 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 percent probability that the quantities actually recovered will equal or exceed the estimated proved reserves; and

(b) at least a 50 percent probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable reserves.

A qualitative measure of the certainty levels pertaining to estimates prepared for the various reserves categories is desirable to provide a clearer understanding of the associated risks and uncertainties. However, the majority of reserves estimates will be prepared using deterministic methods that do not provide a mathematically derived quantitative measure of probability. In principle, there should be no difference between estimates prepared using probabilistic or deterministic methods.

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

3. **Forecast Prices and Costs**

The forecast cost and price assumptions assume increases in wellhead selling prices and take into account inflation with respect to future operating and capital costs. Crude oil and natural gas benchmark reference pricing, as at December 31, 2006, 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, 2006
FORECAST PRICES AND COSTS

	OIL				NATURAL GAS	NATURAL GAS LIQUIDS					
Year	WTI Cushing Oklahoma ($US/Bbl)	Edmonton Par Price 40° API ($Cdn/Bbl)	Medium Crude 29° API ($Cdn/Bbl)	Hardisty Heavy Crude 12° API ($Cdn/Bbl)	AECO Gas Price ($Cdn/Mmbtu)	Edmonton Pentanes Plus ($Cdn/Bbl)	Edmonton Propane ($Cdn/Bbl)	Edmonton Butane ($Cdn/Bbl)	Spec Ethane ($Cdn/Bbl)	INFLATION RATES(1) %/Year	EXCHANGE RATE(2) ($US/$Cdn)
Forecast											
2007	62.00	70.25	61.25	39.25	7.20	71.75	45.00	56.25	24.25	2	0.87
2008	60.00	68.00	59.25	40.00	7.45	69.25	43.50	50.25	25.25	2	0.87
2009	58.00	65.75	57.25	39.75	7.75	67.00	42.00	48.75	26.25	2	0.87
2010	57.00	64.50	56.00	39.75	7.80	65.75	41.25	47.75	26.50	2	0.87
2011	57.00	64.50	56.00	40.25	7.85	65.75	41.25	47.75	26.50	2	0.87
2012	57.50	65.00	56.50	41.50	8.15	66.25	41.50	48.00	27.75	2	0.87
2013	58.50	66.25	57.75	42.50	8.30	67.50	42.50	49.00	28.25	2	0.87
2014	59.75	67.75	59.00	43.50	8.50	69.00	43.25	50.25	29.00	2	0.87
2015	61.00	69.00	60.00	44.25	8.70	70.50	44.25	51.00	29.50	2	0.87
2016	62.25	70.50	61.25	45.25	8.90	72.00	45.00	52.25	30.00	2	0.87
2017	63.50	71.75	62.50	46.00	9.10	73.25	46.00	53.00	30.75	2	0.87
Thereafter	+2%/year	+2%/year	+2%/year	+2%/year	+2%/year	+2%/year	+2%/year	+2%/year	+2%/year	2	0.87

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, 2006, were $7.07/Mcf for natural gas, $64.46/Bbl for light and medium crude oil, $38.35/Bbl for heavy crude oil and $61.35/Bbl for natural gas liquids.

4. **Constant Prices and Costs**

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

SUMMARY OF PRICING ASSUMPTIONS
as of December 31, 2006
CONSTANT PRICES AND COSTS

Year	OIL Edmonton Par Price 40° API ($Cdn/Bbl)	NATURAL GAS AECO Gas Price ($Cdn/GJ)	NATURAL GAS LIQUIDS Edmonton Pentane ($Cdn/Bbl)	Edmonton Propane ($Cdn/Bbl)	Edmonton Butane ($Cdn/Bbl)	Spec Ethane ($Cdn/Bbl)	EXCHANGE RATE(1) ($US/$Cdn)
Historical (2)							
2006	67.58	6.07	71.55	43.25	54.06	20.43	0.8581

Notes:
(1) The exchange rate used to generate the benchmark reference prices in this table.
(2) Prices as at December 31, 2006.

5. **Future Development Costs**

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

Year	Forecast Prices and Costs Proved Reserves ($000)	Forecast Prices and Costs Proved Plus Probable Reserves ($000)	Constant Prices and Costs Proved Reserves ($000)	Constant Prices and Costs Proved Plus Probable Reserves ($000)
2007	4,891	11,538	4,891	11,538
2008	1,905	4,716	1,868	4,623
2009	0	0	0	0
2010	0	53	0	50
2011	0	0	0	0
Thereafter	10	10	8	8
Total Undiscounted	6,805	16,317	6,767	16,220
Total Discounted at 10%	6,319	15,131	6,286	15,048

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

6. 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.**

7. Both the constant and forecast price and cost assumptions assume the continuance of current laws and regulations.

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

Reconciliations of Changes in Reserves and Future Net Revenue

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

	LIGHT AND MEDIUM OIL			HEAVY OIL			ASSOCIATED & NON-ASSOCIATED GAS			NATURAL GAS LIQUIDS		
FACTORS	Net Proved (Mbbl)	Net Probable (Mbbl)	Net Proved Plus Probable (Mbbl)	Net Proved (Mbbl)	Net Probable (Mbbl)	Net Proved Plus Probable (Mbbl)	Net Proved (MMcf)	Net Probable (MMcf)	Net Proved Plus Probable (MMcf)	Net Proved (Mbbl)	Net Probable (Mbbl)	Net Proved Plus Probable (Mbbl)
December 31, 2005	286	85	371	926	786	1,712	10,648	3,960	14,608	78	25	102
Extensions	0	0	0	1,397	613	2,010	354	1,620	1,974	0	11	12
Improved Recovery	88	56	144	0	0	0	205	118	323	12	6	18
Technical Revisions	16	4	21	142	(119)	23	(287)	(357)	(643)	7	(3)	4
Discoveries	0	0	0	0	0	0	974	924	1,895	5	4	9
Acquisitions	0	0	0	0	0	0	0	0	0	0	0	0
Dispositions	(8)	0	(8)	0	0	0	(4,406)	(1,518)	(5,924)	0	0	0
Economic Factors	1	0	1	2	2	4	53	20	73	0	0	0
Production	(30)	0	(30)	(260)	0	(260)	(1,588)	0	(1,588)	(18)	0	(18)
December 31, 2006	353	145	499	2,207	1,282	3,489	5,951	4,768	10,719	84	44	128

Note:
(1) Figures may not add due to rounding.

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

PERIOD AND FACTOR	Year Ended December 31, 2006 (M$)
Estimated Future Net Revenue at December 31, 2005 (after Income Tax)	66,382
Sales and Transfers of Oil and Gas Produced, Net of Production Costs and Royalties	(17,058)
Net Change in Prices, Production Costs and Royalties Related to Future Production	(19,744)
Changes in Previously Estimated Development Costs Incurred During the Period	2,174
Changes in Estimated Future Development Costs	1,044
Extensions and Improved Recovery	35,477
Discoveries	6,096
Acquisitions of Reserves	0
Dispositions of Reserves	(14,610)
Net Change Resulting from Revisions in Quantity Estimates	2,047
Accretion of Discount	7,491
Net Change in Income Taxes	489
Net Change in Royalty Tax Credits	(2,299)
Other Changes	(9,732)
Estimated Future Net Revenue at December 31, 2006 (after Income Tax)	57,757

Additional Information Relating to Reserves Data

Undeveloped Reserves

Proved and probable undeveloped reserves have been estimated in accordance with procedures and standards contained in the COGE Handbook. The significant majority of the undeveloped reserves are 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, 2006, which forms part of the Corporation's 2006 Annual Report, which discussion and analysis is incorporated herein by reference.

Other Oil and Gas Information

Oil And Gas Wells

The following table sets forth the number and status of wells in which the Corporation has a working interest as at December 31, 2006.

	Oil Wells				Natural Gas Wells			
	Producing		Non-Producing		Producing		Non-Producing	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Alberta	46	31.4	17	13.1	43	10.7	33	12.8
British Columbia	0	0.0	1	0.4	2	1.2	7	2.3
Saskatchewan	15	11.8	6	4.8	0	0.0	1	1.0
Total	61	43.2	24	18.3	45	11.9	41	16.1

Properties with no Attributable Reserves

The following table sets out the Corporation's developed and undeveloped land holdings as at December 31, 2006.

	Developed Acres		Undeveloped Acres		Total Acres	
	Gross	Net	Gross	Net	Gross	Net
Alberta	52,755	18,993	55,307	27,615	108,062	46,608
British Columbia	6,775	2,664	12,148	3,856	18,923	6,520
Saskatchewan	2,955	2,641	8,495	7,385	11,490	10,026
Total	62,525	24,298	75,950	38,856	138,475	63,154

Of the Corporation's undeveloped land, rights to explore, develop and exploit 11,197 (3,992 net) acres expire by December 31, 2007. 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 136 (75.0 net) wells totalling $2.9 million (undiscounted) and 154 (91.0 net) wells totalling $3.6 million (undiscounted) are included in the estimate of future net revenue from total proved and total proved plus probable reserves, respectively in the GLJ Report.

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

The Corporation does expect to incur up to $0.5 in abandonment or reclamation expenses in the next three fiscal years to reclaim 33 (11.3 net) abandoned wells, which are not included in the GLJ Report.

Tax Horizon

As at December 31, 2006, the Corporation has approximately $55.5 million of tax pools,of which $14.9 million are Canadian Exploration expense pools and $25.9 million are Canadian Development expense pools, therefore the Corporation does not expect to pay income taxes in 2007.

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, 2006:

	($'000)
Land acquisition costs	4,822
Seismic acquisition costs	1,081
Exploration drilling and completion costs	4,610
Development drilling and completion costs	19,320
Facility and equipment costs	1,282
Dispositions	(30,874)
Capitalized G&A	1,627
Office Equipment	136
Total	2,004

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, 2006:

	Gross	Net
Heavy Oil	25	25.0
Light and Medium Oil	2	0.7
Natural Gas	4	1.2
Service	0	0.0
Dry	2	1.2
Total:	33	28.2

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, 2007 which is reflected in the estimate of future net revenue disclosed in the Forecast Prices and Costs and Constant Prices and Costs tables contained under " - Disclosure of Reserves Data".

	Light and Medium Oil	Heavy Oil	Natural Gas	Natural Gas Liquids	BOE
	Gross (Bbls/d)	Gross (Bbls/d)	Gross (Mcf/d)	Gross (Bbls/d)	Gross (BOE/d)
Proved Producing	194	1,532	3,112	53	2,298
Proved Developed Non-Producing	3	96	128	1	121
Proved Undeveloped	0	274	113	0	292
Total Proved	197	1,902	3,354	54	2,711
Total Probable	27	298	455	3	405
Total Proved Plus Probable	224	2,200	3,808	57	3,116

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							
	2006				2005			
(6:1)	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Average Daily Production[1]								
Light & Medium Crude Oil (Bbls/d)	206	167	161	183	207	154	98	71
Heavy Crude Oil (Bbls/d)	1,168	835	478	679	480	107	74	82
Gas (Mcf/d)	3,528	3,350	8,964	9,946	8,147	5,985	2,879	795
NGLs (Bbls/d)	42	53	57	74	75	84	42	23
Combined (BOE/d)	2,004	1,613	2,190	2,594	2,120	1,343	693	309
Average Price Received								
Light & Medium Crude Oil ($/Bbl)	57.77	70.63	70.79	60.61	63.63	71.13	62.30	58.89
Heavy Crude Oil ($/Bbl)	34.86	47.94	48.99	24.84	24.81	40.60	28.18	24.91
Gas ($/Mcf)	7.45	6.41	6.41	7.76	12.06	9.37	7.62	6.95
NGLs ($/Bbl)	65.47	56.86	71.46	54.31	58.80	59.73	48.71	47.98
Combined ($/BOE)	40.73	47.30	44.01	42.08	60.29	56.90	46.36	41.65
Royalties Paid								
Light & Medium Crude Oil ($/Bbls)	9.92	8.93	6.73	14.53	2.56	24.34	11.59	8.87
Heavy Crude Oil ($/Bbl)	7.23	9.96	9.38	6.07	5.74	7.35	3.84	4.04
Gas ($/Mcf)	1.26	(0.65)	1.40	2.40	3.02	1.63	1.86	2.45
NGLs ($/Bbl)	19.34	15.50	26.45	15.72	14.88	15.31	10.35	4.13
Combined ($/BOE)	7.88	5.27	8.97	12.26	13.67	11.61	10.39	9.73
Transportation Expense	0.45	0.44	0.42	0.34	0.81	0.74	0.19	0.48
Operating Expenses [3]								
Light & Medium Crude Oil ($/Bbl) [3]	11.57	14.65	8.45	11.13	9.74	11.19	7.49	8.18
Heavy Crude Oil ($/Bbl)	14.32	10.81	16.07	11.10	15.37	27.04	16.28	11.33
Gas ($/Mcf) [3]	1.93	2.44	1.41	1.85	1.62	1.86	1.25	1.36
NGLs ($/Bbl) [3]	11.57	14.65	8.45	11.13	9.74	11.19	7.49	8.18
Combined ($/BOE) [3]	13.18	12.69	10.13	11.21	11.02	12.45	8.43	9.01
Netback Received[2]								
Light & Medium Crude Oil ($/Bbl)	36.07	46.19	54.62	34.21	50.73	34.70	41.86	39.78
Heavy Crude Oil ($/Bbl)	13.31	27.17	23.55	7.67	3.70	6.21	8.06	9.54
Gas ($/Mcf)	4.08	4.45	3.52	3.43	7.23	5.73	4.51	3.11
NGLs ($/Bbl)	34.47	24.40	36.56	27.51	34.17	33.23	30.87	35.68
Combined ($/BOE)	19.22	28.90	24.49	18.27	34.79	32.10	27.35	22.43

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, 2006 was 17% light quality crude oil (32° API or greater), 77% heavy crude oil and 6% natural gas and liquids.

For the year ended December 31, 2006, approximately 50% of the Corporation's gross revenue was derived from crude oil production (including natural gas liquids) and 50% 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
2006			
January	5.60	4.68	1,735,356
February	5.50	4.35	578,420
March	4.75	3.90	601,609
April	4.66	3.55	942,097
May	4.28	3.11	810,830
June	3.60	2.80	270,796
July	3.50	2.81	773,738
August	3.50	3.00	792,001
September	3.19	3.02	648,025
October	3.14	2.82	844,900
November	3.29	2.81	679,389
December	3.24	2.57	470,881
2007			
January	3.00	2.67	399,864
February	3.69	2.91	788,943
March (1-14)	3.40	3.20	79,768

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
Alexander C. Brown Calgary, Alberta	Vice President, Exploration	Vice President, Exploration of Rock since January 2004. From January 2003 to January 2004 Vice President, Exploration of Rock Energy. From July 2001 to December 2003 Senior Geologist for Northrock Resources Ltd. (a public oil and gas company). From July 1994 to March 2001 Mr. Brown was employed in various positions of increasing responsibility at Fletcher Challenge Energy Canada (the Canadian subsidiary of a public oil and gas company) the last being Exploration & Development Asset Manager: Provost District.	N/A
Sean E. Moore Calgary, Alberta	Vice President, Production	Vice President, Production of Rock since January 2004. From January 2003 to January 2004 Vice President, Production of Rock Energy. From October 2001 to January 2003 Deep Plains Business Unit Manager for Vintage Petroleum Canada Inc. (the Canadian subsidiary of a public oil and gas company). From 1992 to March 2001 Mr. Moore was employed in various positions of increasing responsibility at Fletcher Challenge Energy Canada the last being Vice President Exploration and Development until it was purchased by Apache Canada Ltd. (the Canadian subsidiary of a public oil and gas company). Mr. Moore continued on for transitional purposes with Apache Canada Ltd. until June 2001 as a consulting engineer.	N/A
Grant A. Zawalsky Calgary, Alberta	Corporate Secretary	Partner of Burnet, Duckworth & Palmer LLP (lawyers)	N/A
Stuart G. Clark(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
Matthew J. Brister(3)(4) Calgary, Alberta	Director	Since August 2003 President of Storm Ventures International Inc. (a private oil and gas company). From August 2002 to July 2004 President and CEO of Storm Energy Ltd. (a public oil and gas company). From November 1998 to August 2002 President and CEO of Storm Energy Inc. (a public oil and gas company). From January 1987 to July 1998 Mr. Brister was employed in various positions of increasing responsibility the last being President and CEO of Pinnacle Resources Ltd. (a public oil and gas company).	October 28, 2004
James K. Wilson(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 15, 2007, the directors and officers of the Corporation, as a group, beneficially owned, directly or indirectly, 2,865,077 common shares or approximately 14.6% of the issued and outstanding common shares of the Corporation .

Corporate Cease Trade Orders or Bankruptcies

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

Penalties or Sanctions

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

Personal Bankruptcies

No director, officer or promoter of the Corporation, or a shareholder holding sufficient securities of the Corporation to affect materially the control of the Corporation, or a personal holding company of any such persons, has, within the last 10 years, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or being subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold the assets of the individual.

Conflicts of Interest

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

ESCROWED SECURITIES

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

AUDIT COMMITTEE INFORMATION

Audit Committee Mandate and Terms of Reference

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

Composition of the Audit Committee

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

Relevant Education and Experience

Mr. James K. Wilson is the Chairman of the Audit Committee and holds a Bachelor of Commerce degree and a Chartered Accountant designation. Mr. Wilson is currently the Chief Financial Officer of an oil and gas company and has held that position at several predecessor companies. Mr. Wilson has over 24 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 $61,960 in 2006 ($48,752 in 2005).

Audit and Related Fees

The aggregate fees billed in the last fiscal year for assurance audit related services by the Corporation's external auditor were $24,384 in 2006 ($92,456 in 2005). The services provided consisted of review of quarterly statements and disclosure and in 2005 advice on accounting matters related to the business acquisition.

Tax Fees

The aggregate fees billed in the last fiscal year for professional services rendered by the Corporation's external auditor for tax compliance, tax advice and tax planning were $47,000 in 2006 ($58,750 in 2005).

LEGAL PROCEEDINGS

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

INTERESTS OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

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

MATERIAL CONTRACTS

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

INTERESTS OF EXPERTS

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

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

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

In addition, none of the aforementioned persons or companies, nor any director, officer or employee of any of the aforementioned persons or companies, is or is expected to be elected, appointed or employed as a director, officer or employee of the Corporation or of any associate or affiliate of the Corporation.

HUMAN RESOURCES

The Corporation currently employs 17 full-time employees and utilizes the services of professionals, as required from time to time on a contract or consulting basis. The Corporation intends to add additional professional and administrative staff as the needs arise.

AUDITORS, TRANSFER AGENT AND REGISTRAR

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

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

RISK FACTORS

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

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

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

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

All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of federal, provincial and local laws and regulations. Environmental legislation provides for, among other things, restrictions and prohibitions on spills, releases or emissions of various substances produced in association with oil and natural gas operations. The legislation also requires that wells and facility sites be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. Compliance with such legislation can require significant expenditures and a breach of applicable environmental legislation may result in the imposition of fines and penalties, some of which may be material. Environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liability and potentially increased capital expenditures and operating costs. The discharge of oil, natural gas or other pollutants into the air, soil or water may give rise to liabilities to governments and third parties and may require the Corporation to incur costs to remedy such discharge. Although the Corporation believes that it will be in material compliance with current applicable environmental regulations no assurance can be given that environmental laws will not result in a curtailment of production or a material increase in the costs of production, development or exploration activities or otherwise adversely affect the Corporation's financial condition, results of operations or prospects. 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 those of the Corporation. Given the evolving nature of the debate related to climate change and the control of greenhouse gases and resulting requirements, it is not possible to predict either the nature of those requirements or the impact on the Corporation and its operations and financial condition. See "Industry Conditions – Environmental Regulation".

Canada is a signatory to the United Nations Framework Convention on Climate Change and has ratified the Kyoto Protocol established thereunder to set legally binding targets to reduce nationwide emissions of carbon dioxide, methane, nitrous oxide and other so-called "greenhouse gases". The Corporation's exploration and production facilities and other operations and activities emit greenhouse gases which will likely subject the Corporation to possible future legislation regulating emissions of greenhouse gases. The Government of Canada has proposed a Bill, which suggests further legislation will set greenhouse gases emission reduction requirements for various industrial activities, including oil and gas exploration and production. Future federal legislation, together with provincial emission reduction requirements, such as those included in Alberta's Climate Change and Emissions Management Act (partially in force), may require the reduction of emissions (or emissions intensity) produced by the Corporation's expected operations and facilities. The direct or indirect costs of these regulations may adversely affect the expected business of the Corporation. 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 60% of the Corporation's 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. All current legislation is a matter of public record and Rock is unable to predict what additional legislation or amendments may be enacted. Outlined below are some of the principal aspects of legislation, regulations and agreements governing the oil and gas industry.

Pricing and Marketing – Oil, Natural Gas and Associated Products

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

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

The price of natural gas is determined by negotiation between buyers and sellers. Natural gas exported from Canada is subject to regulation by the NEB and the Government of Canada. Exporters are free to negotiate prices and other terms with purchasers, provided that the export contracts must continue to meet certain other criteria prescribed by the NEB and the Government of Canada. Natural gas exports for a term of less than 2 years or for a term of 2 to 20 years (in quantities of not more than 30,000 m^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.

On March 3, 2003 the Department of Finance (Canada) released a technical paper entitled "Improving the Income Taxation of the Resource Sector in Canada" (the "Technical Paper"). In November, 2003 the Tax Act was amended to provide the following initiatives applicable to the oil and gas industry (to a maximum of $2,000,000) to be phased in over a five year period: (i) a reduction of the federal statutory corporate income tax rate on income earned from resource activities from 28% to 21%, beginning with a one percentage point reduction effective January 1, 2003, and (ii) a deduction for federal income tax purposes of actual provincial and other Crown royalties and mining taxes paid and the elimination of the 25% resource allowance.

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 in "new oil" and "old oil" depending on when the oil pools were discovered. If prior to March 31, 1974 is considered "old oil", if after March 31, 1974 and before September 1, 1992, 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, 2007, 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 whilst 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.

On February 16, 2007, the Alberta Government announced that a review of the province's royalty and tax regime (including income tax and freehold mineral rights tax) pertaining to oil, gas and oil sands will be conducted by a panel of experts, with the assistance of individual Albertans and key stakeholders. The purpose of this process is to ensure that Albertans are receiving a fair share from energy development through royalties, taxes and fees. The issues to be reviewed during this examination process are: (i) undertaking a comparison of Alberta's royalty system to other oil and gas producing jurisdictions, taking into account investment economics and industry returns and risks in Alberta; (ii) whether Alberta's royalty system is sufficiently sensitive to market conditions; (iii) whether the current revenue minus cost system for oil sands royalties is optimal; (iv) which programs built into the existing royalty system should be retained or strengthened, and which should be adapted or eliminated; (v) how the tax treatment of the oil and gas sector compares to other sectors and jurisdictions; (vi) the economic and fiscal impacts of any possible changes to the royalty and corporate tax structures; and (vii) how existing resource development should be treated if changes are to be made to the fiscal regime. The review panel is to produce a final report that will be presented to the Minister of Finance by August, 31, 2007.

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.

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.

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. No additional expenses are foreseen that are associated with complying with the new regulations. Rock is committed to meeting its responsibilities to protect the environment wherever it operates and anticipates making increased expenditures of both a capital and an expense nature as a result of the increasingly stringent laws relating to the protection of the environment and will be taking such steps as required to ensure compliance with the AEPEA and similar legislation in other jurisdictions in which it operates. Rock believes that it is in material compliance with applicable environmental laws and regulations and also believes that it is reasonably likely that the trend towards stricter standards in environmental legislation and regulation will continue.

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

In December 2002, the Government of Canada ratified the Kyoto Protocol ("Protocol"). The Protocol calls for Canada to reduce its greenhouse gas emissions to 6% below 1990 "business-as-usual" levels between 2008 and 2012. Given revised estimates of Canada's normal emissions levels, this target translates into an approximately 40% gross reduction in Canada's current emissions. 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.

Trends

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

The first trend is the volatility of commodity prices. Natural gas is a commodity influenced by factors within North America. A tight supply-demand balance for natural gas causes significant elasticity in pricing, whereas higher than average storage levels tend to depress natural gas pricing. Drilling activity, weather, fuel switching and demand for electrical generation are all factors that affect the supply-demand balance. Changes to any of these or other factors create price volatility.

Crude oil is influenced by the world economy, Organization of the Petroleum Exporting Countries' ability to adjust supply to world demand and weather. Crude oil prices have been kept high by political events causing disruptions in the supply of oil and concern over potential supply disruptions triggered by unrest in the Middle East and more recently have been impacted by weather and increased storage levels. Political events trigger large fluctuations in price levels.

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

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

A third trend currently affecting the oil and gas industry is the impact on capital markets caused by investor uncertainty in the North American economy. The capital market volatility in Canada has also been affected by uncertainties surrounding the economic impact that the Protocol, and other environmental initiatives, will have on the sector and, in more recent times, by the October 31, 2006 proposals of the Federal government of Canada (the "October 31, 2006 Proposals") relating to income trusts and other "specified investment flow-through" entities ("SIFTs"). Pursuant to the existing provisions of the *Income Tax Act* (Canada), to the extent that a SIFT has any income for a taxation year after certain inclusions and deductions, the SIFT will be permitted to deduct all amounts of income which are paid or become payable by it to unitholders in the year. Under the October 31, 2006 Proposals, SIFTs will be liable for tax at a rate consistent with the taxes currently imposed on corporations commencing in January 2011, provided that the SIFT experiences only "normal growth" and no "undue expansion" before then, in which case the tax could be imposed prior to the January 2011 deadline. Although the October 31, 2006 Proposals will not affect the method in which the Corporation will be taxed, they may have an impact on the ability of a SIFT to purchase producing assets from junior oil and gas companies (as well as the price that a SIFT is willing to pay for such an acquisition) thereby affecting exploration and production companies' ability to be sold to a SIFT which has been a key "exit strategy" in recent years for small to mid-sized oil and gas companies. This may be a benefit for the Corporation as it will compete with SIFTs for the acquisition of oil and gas properties from junior producers. However, it may also limit the Corporation's ability to sell producing properties or pursue an exit strategy.

Generally during the past year, the economic recovery combined with increased commodity prices has caused an increase in new equity financings in the oil and gas industry, although the level of same was negatively impacted by the October 31, 2006 Proposals. The Corporation will compete with numerous new companies and their new management teams and development plans in its access to capital. The competitive nature of the oil and gas industry will cause opportunities for equity financings to be selective. The Corporation may have to rely on internally generated funds to conduct their exploration and developmental programs.

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 to be held on May 15, 2007. Additional financial information is contained in the consolidated financial statements of the Corporation for the year ended December 31, 2006 and the Management's Discussion and Analysis contained in the Corporation's Annual Report for the year ended December 31, 2006.

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

(a) when the securities of the Corporation are in the course of a distribution pursuant to a preliminary short form prospectus or a short form prospectus:

    (i) one copy of the Corporation's annual information form, together with one copy of any document, or the pertinent pages of any document, incorporated therein by reference;

    (ii) one copy of the comparative financial statements of Rock for its most recently completed financial year in respect of which such financial statements have been issued, together with the report of the auditor thereon, and one copy of any interim financial statements of the Corporation subsequent to the financial statements for Rock's most recent financial year;

    (iii) one copy of the management information circular of the Corporation in respect of its most recent annual meeting of shareholders that involved the election of directors or one copy of any annual filing prepared in lieu of that circular, as appropriate, and

    (iv) one copy of any other document that is incorporated by reference into the preliminary short form prospectus or the short form prospectus and are not required to be provided under (i) to (iii) above; or

(b) at any other time, a copy of the documents referred to in clauses (a)(i), (ii) or (iii) above, provided the Corporation may require a payment of a reasonable charge if the request is made by a person or Corporation who is not a security holder of the Corporation.

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

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, 2006. The reserves data consist of the following:

   (a) (i) proved and proved plus probable oil and gas reserves estimated as at December 31, 2006 using forecast prices and costs; and

   (ii) the related estimated future net revenue; and

   (b) (i) proved oil and gas reserves estimated as at December 31, 2006 using constant prices and costs; and

   (ii) the related estimated future net revenue.

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

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

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

5. The following table sets forth the estimated future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated by us for the year ended December 31, 2006, 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 February 15, 2007	Canada	$nil	$105,688	$nil	$105,688

6. In our opinion, the reserves data respectively evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook.

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

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

Executed as to our report referred to above:

GLJ Petroleum Consultants Ltd.
Calgary, Alberta, Canada
February 27, 2007

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 consist of the following:

(a) (i) proved and proved plus probable oil and gas reserves estimated as at December 31, 2006 using forecast prices and costs; and

(ii) the related estimated future net revenue; and

(b) (i) proved oil and gas reserves estimated as at December 31, 2006 using constant prices and costs; and

(ii) the related estimated future net revenue.

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

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

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

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

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

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

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

(g) the filing of the report of the independent qualified reserves evaluator on the reserves data; and

(h) the content and filing of this report.

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

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

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

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

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

March 15, 2007

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.

rockenergy

PRESS RELEASE

Rock Energy 2006 Year End Results

March 16, 2007, 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, 2006. 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, 2006 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 2006 Rock accomplished the following:

- Initiated and concluded an asset rationalization program;
- Consolidated our asset base into two core areas and increased our average working interest and operatorship;
- Strengthened our balance sheet through the sale process in July;
- Demonstrated the capability of our technical team by drilling 33 wells with a 96 percent success rate;
- Added more than 3.6 million boe of proved plus probable reserves with a finding and development cost of $11.28/boe and generated a re-cycle ratio of 1.6;
- Increased our production rate from 1,400 boe per day following the disposition in July to a rate in March 2007 exceeding 2,200 boe per day while averaging 2,098 boe per day for the year (an 87 percent increase from the year before);
- Generated cash flow of $13.9 million ($0.71 per share) for the year, a 21% increase over the prior year despite lower product prices;
- Increased our net asset value per share by 42 percent to $5.34 per basic share; and
- Built a strong inventory of drilling prospects, totalling more than 80 drilling locations, to drive our future growth.

The past year was one of transformation for Rock. This time last year we were managing an asset base that was largely non-operated and was spread across the entire Western Canada Sedimentary Basin. These assets were acquired in 2005 and provided us with a diverse portfolio of opportunity. We took that portfolio and determined where we thought we should focus and apply our resources to build a strong, viable company with the right mix. Our plan last year was to rationalize Rock's asset base and engage our grassroots exploration program. We did what we set out to do. We have restored Rock's production level and reserve base, focused into two core areas, and have accumulated a large inventory of drilling locations.

Rock engaged in a rationalization program in the first half of last year that reduced our production base to 1,400 boe per day by July. We emerged with two core areas that gave us increased focus, higher working interests and increased operatorship. Though we originally intended to only sell a net 200-300 boe per day while engaging in a swap of producing assets, it became evident during the process that our drilling inventory was superior to the assets being offered for swap. In addition, the offers for our assets were above our estimates of value and provided an 80 percent rate of return on our investment. We had acquired the assets for $20.6 million, had generated $6.2 million in cash flow after capital costs, and were now being offered $30.9 million to sell them. At that point we decided on a larger disposition and to reinvest the extra funds into our drilling program.

Our drilling program has added 3.6 million boe of proven plus probable reserves and increased our total reserve base to 7.9 million boe (proven plus probable) after accounting for the sale of properties and the production during the year, and restore our production level to it's current rate of over 2,200 boe per day.

Rock has emerged from its year of transformation with the "right mix" of; production (heavy oil, light oil and natural gas); risk and reward; geographic locations; and financial capability. The heavy oil component of our opportunity base provides a large inventory, exceeding 50 drilling locations, of low-risk projects that generate solid economic returns, and can be drilled and brought on-stream quickly. In our West Central region we have identified 25-30 drilling locations for natural gas. Though these gas targets have longer cycle times to bring on production, they also possess larger reserve potential and upside. It is the combination of projects that positions our company to generate growth in production and value.

2007 Drilling Program

Rock's Board of Directors has approved an initial capital budget of $22 million for 2007 (of which $2.0 million was spent in December 2006). During the remainder of the year the Company expects to drill approximately 18 (13.6 net) wells and increase production to exit the year at 2,600-2,800 boe per day. This would achieve 20-25 percent growth in exit volumes, before any significant contribution from our exploration projects.

The drilling program will be made up of 8-10 heavy oil wells and, two natural gas wells in our Plains region, and six to eight natural gas wells in our West Central region. Of the West Central region wells; two will be high-impact exploration wells at Kakwa and the rest will be lower-risk exploration wells in the Greater Kaybob and Musreau areas.

So far this year we have drilled three (3.0 net) heavy oil wells and one (1.0 net) abandoned well in the Plains region, and two natural gas wells in the West Central region, one (0.12 net) well at Waskahigan, and one (0.30 net) at Kakwa. The gas well at Waskahigan was completed with disappointing results and is currently a standing cased gas well; the well at Kakwa is cased and is being completed with production testing to likely occur following spring break-up.

Assuming average commodity prices $US65.00 per bbl of W.T.I. crude oil and Cdn$7.50 per mcf of natural gas at AECO, Rock's 2007 capital program will generate cash flow of $15 million ($0.76/share). The capital program is expected to be funded with our cash flow and our newly established $23 million debt facility.

Two-thousand seven will be an exciting year for Rock. We have a strong drilling program that is capable of growing our production by 25 percent by the year-end, plus an exploration program that could significantly impact Rock for 2008. The industry's structural landscape has changed, and that is providing opportunities as well as challenges for our company. The new environment should serve Rock well. We believe it will prompt the consolidation of smaller oil and natural gas companies, especially those that may have been banking on an early exit, possibly at lower acquisition metrics due to the energy trusts' increased cost of capital. This would provide Rock with increased opportunities for mergers and acquisitions. We believe we are well-positioned to take advantage of the opportunities and will continue to work hard to do so.

Corporate Summary

	Twelve months ended December 31, 2006	Twelve months ended December 31, 2005	Three months ended December 31, 2006	Three months ended December 31, 2005
Financial				
Oil and natural gas revenue ($000)	$ 33,156	$ 22,873	$ 7,535	$ 11,760
Funds from operations ($000) [1]	$ 13,867	$ 11,433	$ 2,644	$ 6,020
Per share – basic	$ 0.71	$ 0.74	$ 0.13	$ 0.31
– diluted	$ 0.71	$ 0.74	$ 0.13	$ 0.31
Net income (loss) ($000)	$ (884)	$ 1,510	$ (119)	$ 747
Per share – basic	$ (0.05)	$ 0.10	$ (0.01)	$ 0.04
– diluted	$ (0.05)	$ 0.10	$ (0.01)	$ 0.04
Capital expenditures, net ($000)	$ 2,004	$ 84,237	$ 6,223	$ 7,768

	As at December 31, 2006	As at December 31, 2005
Working capital including bank debt ($000)	$ (12,580)	$ (24,442)
Common shares outstanding (000)	19,637	19,637
Options outstanding (000)	1,767	1,120

	Twelve months ended December 31, 2006	Twelve months ended December 31, 2005	Three months ended December 31, 2006	Three months ended December 31, 2005
Operations				
Average daily production				
Light crude oil *(bbls/d)*	179	133	206	207
Heavy crude oil *(bbls/d)*	792	187	1,168	480
NGL *(bbls/d)*	57	56	42	75
Natural gas *(mcf/d)*	6,421	4,476	3,528	8,147
Total *(boe/d)*	2,098	1,122	2,004	2,120
Average product prices				
Light crude oil *(Cdn$/bbl)*	$64.46	$ 64.95	$57.77	$ 63.63
Heavy crude oil *(Cdn$/bbl)*	$38.35	$ 27.44	$34.86	$ 24.81
NGL *(Cdn$/bbl)*	$61.35	$ 56.19	$65.47	$ 58.80
Natural gas *(Cdn$/mcf)*	$7.07	$ 10.22	$7.45	$ 12.06
BOE *(Cdn$/boe)*	$43.27	$ 55.85	$40.73	$ 60.29
Operating netback *(Cdn$/boe)*	$22.21	$ 31.98	$19.22	$ 34.79

[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 & 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 discussion and analysis is dated March 15, 2007 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, 2006.

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 are a key measure that demonstrates the ability to generate cash to fund expenditures. Funds from operations are 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 are 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 7, 2006 for projected 2006 and 2007 results. The table below provides the guidance for 2006 with actual results.

2006 Guidance

	2006 Guidance	Actual	Change
2006 Production *(boe/d)*			
Annual	2,100	2,098	0%
Exit	2,200-2,400	2,200	(4)%
2006 Funds from Operations			
Annual	$13.5 million	$13.9 million	3%
Annual *(per share)*	$0.69	$0.71	3%
2006 Capital Budget			
Expenditures	$30 million	$33 million	10%
Gross wells drilled	31	33	6%
Total net debt at year end	$11 million	$12.6 million	15%
Pricing (Fourth Quarter)			
Oil – WTI	US$60.00/bbl	US$60.21/bbl	0%
Natural gas – AECO	$6.67/mcf	$6.69/mcf	0%
US/Cdn dollar exchange rate	0.90	0.88	(2)%

Production averages for the year and the exit rate were within the guidance range. Funds flow from operations was above guidance as higher pricing (lower than budgeted heavy oil differentials and higher realized natural gas prices) more than offset higher operating costs. Capital expenditures were higher than forecast as $2 million of the

2007 capital budget was accelerated into December 2006 in order to take advantage of rig availability and operational efficiencies to drill four (4.0 net) heavy oil wells. As a result debt levels at year-end were slightly above guidance.

Guidance for 2007 has been updated to reflect higher operating costs experienced by the Company and industry and acceleration of the 2007 capital budget into December 2006. The table below updates the Company's previous guidance that was issued November 7, 2006.

	2007 Previous Guidance	2007 Revised Guidance	Change
2007 Production *(boe/d)*			
Annual	2,200	2,200-2,400	5%
Exit	2,600-2,800	2,600-2,800	0%
2007 Funds from Operations			
Annual	$15 million	$15 million	0%
Annual – *(per share)*	$0.76	$0.76	0%
2007 Capital Budget			
Expenditures	$22 million	$20 million	(9)%
Gross wells drilled	20-25	16-21	(18)%
Total net debt at year-end	$18 million	$18 million	0%
Pricing (Annual)			
Oil – WTI	US$65.00/bbl	US$65.00/bbl	0%
Natural gas – AECO	Cdn$7.50/mcf	Cdn$7.50/mcf	0%
US/Cdn dollar exchange rate	0.90	0.90	0%

Operating costs have been trending up and, as a result, Rock has increased the per boe cost by $0.50/boe to approximately $11.25 per boe including transportation costs. The acceleration of capital into December 2006 has caused management to implement an annual average range for production as the wells drilled came on-stream in the first quarter instead of the third quarter. The annual cash flow associated with the increased production has been offset by the increase in operating costs. As a result, the year's cash flow and year-end debt levels have not been affected. While light oil pricing has initially been lower than forecast for 2007, heavy oil differentials have improved and, as a result, we have not altered our oil price. The Company has put in a new debt facility which increased the bank line from $18 million to $23 million. Capital expenditures in excess of funds from operations are projected to be $5 million and can be funded through this facility. The year-end debt to cash flow ratio is projected to be approximately 1.2:1. 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.

Production by Product

	12 Months Ended 12/31/06	12 Months Ended 12/31/05	Change	3 Months Ended 12/31/06	3 Months Ended 12/31/05	Change
Natural gas *(mcf/d)*	6,421	4,476	43%	3,528	8,147	(57)%
Oil *(bbls/d)*	179	133	35%	206	207	(1)%
Heavy Oil *(bbls/d)*	792	187	324%	1,168	480	143%
NGL *(bbls/d)*	57	56	2%	42	75	(44)%
Total (boe/d) *(6:1)*	2,098	1,122	87%	2,004	2,120	(5)%

Production by Area

	12 Months Ended 12/31/06	12 Months Ended 12/31/05	Change	3 Months Ended 12/31/06	3 Months Ended 12/31/05	Change
West Central Alberta *(boe/d)*	972	598	63%	652	1,189	(45)%
Plains *(boe/d)*	795	242	229%	1,171	510	130%
Other *(boe/d)*	331	282	17%	181	421	(57)%
Total (boe/d) *(6:1)*	2,098	1,122	87%	2,004	2,120	(5)%

Production increases for the year ended December 31, 2006 primarily came from two sources. First are the ELM/Optimum/Qwest acquisitions that were completed in stages and closed in April and June 2005, partially offset by the sale of approximately 820 boe per day of production in July 2006. Second, the Company's operated grassroots drilling program contributed the heavy oil additions in the Plains area and additional production from drilling on the acquired properties. Early in January 2007 Rock's production exceeded 2,200 boe per day.

Production decreased by 5 percent in the fourth quarter of 2006 from the same period last year as the property dispositions in the third quarter more than offset the additions from operational activities. Production additions in the quarter primarily came from the Plains core area, which added heavy oil production, and the workovers completed at Medicine River, which added light oil production. As a result of these activities the Company's product mix shifted more towards heavy oil.

Product Prices

	12 Months Ended 12/31/06	12 Months Ended 12/31/05	Change	3 Months Ended 12/31/06	3 Months Ended 12/31/05	Quarterly Change
Realized Product Prices						
Natural gas *($/mcf)*	7.07	10.22	(31)%	7.45	12.06	(38)%
Oil *($/bbl)*	64.46	64.95	(1)%	57.77	63.63	(9)%
Heavy oil *($/bbl)*	38.35	27.44	40%	34.86	24.81	41%
NGL *($/bbl)*	61.35	56.19	9%	65.47	58.80	11%
Combined average ($/boe) *(6:1)*	43.27	55.85	(23)%	40.73	60.29	(32)%

	12 Months Ended 12/31/06	12 Months Ended 12/31/05	Change	3 Months Ended 12/31/06	3 Months Ended 12/31/05	Quarterly Change
Average Reference Prices						
Natural gas – Henry Hub Daily Spot *(US$/mcf)*	6.75	8.89	(24)%	6.69	12.27	(45)%
Natural gas – AECO C Daily Spot *($/mcf)*	6.54	8.77	(25)%	6.99	11.43	(39)%
Oil – WTI Cushing, Oklahoma *(US$/bbl)*	66.22	56.56	17%	60.21	60.02	0%
Oil – Edmonton Light *($/bbl)*	72.77	68.72	6%	64.49	71.17	(9)%
Heavy Oil – Lloydminster blend *($/bbl)*	50.07	42.99	16%	43.84	41.81	5%
US/Cdn $ exchange rate	0.882	0.826	7%	0.878	0.852	3%

For the year and quarter ended December 31, 2006 the Company experienced higher heavy oil prices (approximately 40 percent increase) and lower natural gas prices (more than 30 percent reduction) than in the prior year's periods. Higher heavy oil prices resulted from higher WTI prices for the year and a significant decrease in the heavy oil to light oil differential. Structural changes in the marketplace such as pipeline reversals that have taken more heavy crude production out of Alberta to refineries in the mid-continent United States have contributed to the improvement in the heavy oil differential. The Company expects that these and other structural changes will continue to benefit the heavy oil market price. Natural gas prices have suffered from high storage levels as winter was delayed and the fourth quarter of 2006 was warmer than average. The combination of lower natural gas prices and the increase in heavy oil production in Rock's product mix over 2005 has caused the Company's weighted average per boe price to decrease by 23 percent for the year and 32 percent for the fourth quarter from the prior year's periods.

REVENUE

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

Oil and Natural Gas Revenue

	12 Months Ended 12/31/06	12 Months Ended 12/31/05	Change	3 Months Ended 12/31/06	3 Months Ended 12/31/05	Quarterly Change
Natural gas	$ 16,560	$ 16,695	(1)%	$ 2,408	$ 9,043	(73)%
Oil	4,195	3,152	33%	1,073	1,214	(12)%
Heavy Oil	11,124	1,871	495%	3,790	1,095	246%
NGL	1,277	1,155	11%	264	408	(35)%
	33,156	22,873	45%	7,535	11,760	(36)%
Other revenue	$ 198	$ 317	(38)%	$42	$ 100	(58)%

Oil and natural gas revenue increased by 45 percent for the year ended December 31, 2006 over 2005 due to higher production levels, particularly of heavy oil, which more than offsett the decline in product prices, particularly of natural gas. For the fourth quarter of 2006 oil and natural gas revenue decreased by 36 percent from the same period in 2005 as lower natural gas production and prices more than offset the increase in heavy oil production and prices. Other revenue decreased in 2006 from 2005 as the Company sold the property that was generating sulphur as part of the asset rationalization program in the third quarter of 2006.

Royalties

	12 Months Ended 12/31/06	12 Months Ended 12/31/05	Change	3 Months Ended 12/31/06	3 Months Ended 12/31/05	Quarterly Change
Royalties	$6,881	$5,027	37%	$1,452	$2,666	(46)%
As a percentage of oil and natural gas revenue	20.8%	22.0%	(5)%	19.3%	22.7%	(15)%
Per boe *(6:1)*	$8.98	$12.28	(27)%	$7.88	$13.67	(42)%

Royalties increased for the year ended December 31, 2006 over the prior year due to higher production levels partially offset by lower natural gas prices and the benefit of Alberta Royalty Tax Credit (ARTC). For the fourth quarter of 2006 royalties decreased from the fourth quarter of 2005 due to lower production, lower natural gas prices and the ARTC benefit. Royalties as a percentage of revenue and on a per-boe basis decreased in the 2006 periods from the 2005 periods primarily due to lower natural gas prices, ARTC benefit and the Company's production mix including a higher heavy oil component, which generally has a lower associated royalty rate. The Company is forecasting a royalty rate of 22 percent for 2007 as the ARTC program has been eliminated effective January 1, 2007.

Operating Expenses

	12 Months Ended 12/31/06	12 Months Ended 12/31/05	Change	3 Months Ended 12/31/06	3 Months Ended 12/31/05	Quarterly Change
Operating expense	$ 8,947	$ 4,470	100%	$ 2,429	$ 2,149	13%
Transportation costs	308	275	12%	83	158	(47)%
	9,255	4,745	95%	2,512	2,307	9%
Per boe *(6:1)*	$12.08	$11.59	4%	$13.63	$11.83	15%

Operating costs for the year ended December 31, 2006 have increased over 2005 primarily due to higher production. Operating expenses for both the year ended December 31, 2006 and the fourth quarter of 2006 include approximately $200 of natural gas processing costs related to 2005. Excluding these prior-period processing costs, operating costs for 2006 are $11.83 per boe, a 2 percent increase over 2005, and $12.56 per boe for the fourth quarter of 2006, a 6 percent increase over the prior period. Compared to the third quarter of 2006, fourth quarter per boe operating expenses have decreased by 4 percent once the 2005 processing costs are excluded. Operating costs per boe did not decrease as much as expected in the fourth quarter in part due to higher service costs associated with heavy oil operations and higher road and lease maintenance costs.

Heavy oil unit costs tend to be higher in the first several months of producing operations (the "clean-up period") due to high initial sand production, additional fuel costs incurred until the operation is capable of running on casing-head gas and injected load oil being used during the clean-up period, which reduces the sales volume from the operations. Heavy oil operating costs have decreased year-over-year by about 20 percent to about $13.00 per boe as the base level of production has increased and start-up operations have less of an impact on overall costs. The Company expects heavy oil costs per boe to continue to decrease in 2007. Transportation costs for the fourth quarter of 2006 decreased from the prior year's period as a result of the properties sold in the third quarter of 2006. Operating expenses per boe, including transportation expense, are forecast to be approximately $11.25 per boe in 2007.

General and Administrative (G&A) Expense

	12 Months Ended 12/31/06	12 Months Ended 12/31/05	Change	3 Months Ended 12/31/06	3 Months Ended 12/31/05	Quarterly Change
Gross	$ 3,905	$ 2,275	69%	$ 1,085	$ 814	27%
Per boe *(6:1)*	5.10	5.55	(9)%	5.89	4.17	34%
Capitalized	1,627	864	83%	395	288	19%
Per boe *(6:1)*	2.12	2.11	(2)%	2.14	1.47	26%
Net	2,278	1,411	61%	690	526	31%
Per boe *(6:1)*	$2.97	$3.44	(14)%	$3.74	$2.70	39%

G&A expense increased on an absolute basis in 2006 over 2005 as the Company's operations continued to grow and new staff was added. G&A expense on a per-boe basis for the year ended December 31, 2006 dropped from the prior year's period as production increased. For the fourth quarter of 2006, G&A expense per boe increased over 2005 as production decreased as a result of the property dispositions in the third quarter of 2006, because costs for year-end activities increased and because approximately $56 ($0.30 per boe) of bad debt related to the ELM/Optimum/Qwest acquisition was written off. Rock capitalizes certain G&A expenses based on personnel involved in the exploration and development initiatives, including salaries and related overhead costs. G&A expenses are expected to rise in 2007 on an absolute basis as industry costs increase.

Interest Expense

	12 Months Ended 12/31/06	12 Months Ended 12/31/05	Change	3 Months Ended 12/31/06	3 Months Ended 12/31/05	Quarterly Change
Interest expense (recovery)	$ 924	$ 457	100%	$ 141	$ 261	(46)%
Per boe *(6:1)*	$1.21	$1.12	8%	$0.76	$1.34	(43)%

Interest expense for 2006 doubled over 2005 as a result of higher average bank debt for the year. For the fourth quarter of 2006 interest expense was about half of interest expense for the same period of 2005 as bank debt was reduced in the third quarter of 2006 with proceeds from the asset rationalization program. Interest expense is expected to increase in 2007 due to higher average bank debt but to be approximately the same on a per boe basis as in 2006.

Depletion, Depreciation, and Accretion (DD&A)

	12 Months Ended 12/31/06	12 Months Ended 12/31/05	Change	3 Months Ended 12/31/06	3 Months Ended 12/31/05	Quarterly Change
D&D expense	$ 13,989	$ 8,211	70%	$ 2,707	$ 3,994	(32)%
Per boe *(6:1)*	$18.27	$20.05	(9)%	$14.69	$20.48	(28)%
Accretion expense	$ 129	$ 76	70%	$ 34	$ 31	10%
Per boe *(6:1)*	$0.17	$0.19	(11)%	$0.18	$0.16	13%

Depletion and depreciation expense for year ended December 31, 2006 increased over the prior year due to higher production but decreased for the fourth quarter of 2006 from the 2005 period primarily as Company reserves increased faster than the cost base. Reserve additions in 2006 also caused the depletion and depreciation expense per boe to decrease in 2006 from 2005.

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 or constructing facilities. Similarly, this obligation can also be reduced as a result of abandonment work undertaken and reducing future obligations. During the year ended December 31, 2006 capital programs increased the underlying ARO by $413 (December 31, 2005 – $1,583) and actual expenditures on abandonments were $104 (December 31, 2005 – $44).

INCOME TAX

The Company began to pay capital taxes in 2005 as its capital base increased significantly following the acquisitions in 2005. Federal large corporations tax was eliminated beginning in 2006; however, 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 2007 as the Company and its subsidiaries have estimated resource and other pools available at December 31, 2006 (after the allocation of deferred partnership income) of approximately $55.2 million as set out below:

CEE	$ 14.9 million
CDE	$ 25.9 million
UCC	$ 12.8 million
Loss carry-forwards	$ 0.3 million
Other	$ 1.3 million
Total	$ 55.2 million

Funds from Operations and Net Income

	12 Months Ended 12/31/06	12 Months Ended 12/31/05	Change	3 Months Ended 12/31/06	3 Months Ended 12/31/05	Quarterly Change
Funds from operations	$13,867	$11,433	21%	$2,644	$6,020	(56)%
Per boe *(6:1)*	$18.11	$27.92	(35)%	$14.35	$30.86	(54)%
Per share:						
Basic	$0.71	$ 0.74	(4)%	$0.13	$ 0.31	(58)%
Diluted	$0.71	$ 0.74	(4)%	$0.13	$ 0.31	(58)%
Net income (loss)	($884)	$ 1,510	(159)%	($119)	$ 747	(116)%
Per boe *(6:1)*	($1.15)	$3.69	(131)%	($0.65)	$3.83	(117)%
Per share:						
Basic	($0.05)	$ 0.10	(150)%	($0.01)	$ 0.04	(125)%
Diluted	($0.05)	$ 0.10	(150)%	($0.01)	$ 0.04	(125)%
Weighted average shares outstanding:						
Basic	19,637	15,437	27%	19,637	19,596	0%
Diluted	19,655	15,501	27%	19,637	19,682	0%

The Company did not issue any shares in 2006. In 2005 the majority of shares issued were for the acquisitions completed in the second quarter of 2005, when 10.3 million shares were issued.

Funds from operations for the year ended December 31, 2006 increased by 21 percent over 2005 as the increase in production more than offset the decrease in realized prices, primarily for natural gas, and the increase in royalties, operating, G&A and interest costs. On a per-boe basis 2006 funds from operations decreased by 35 percent from 2005 primarily as the reduction in realized prices more than offset the reduction in royalties. For the fourth quarter of 2006 funds from operations decreased by approximately 56 percent on an absolute and 54 percent on a per boe-basis from to the prior year's periods as the reduction in prices (primarily for natural gas) and increase in operating and G&A costs more than offset the reduction in royalties. The Company generated a net loss for the year and quarter ended December 31, 2006 as the level of depletion and increase in stock-based compensation exceeded funds from operations.

Capital Expenditures

($000)	12 Months Ended 12/31/06	12 Months Ended 12/31/05	Change	3 Months Ended 12/31/06	3 Months Ended 12/31/05	Quarterly Change
Land	$ 4,822	$ 3,737	29%	$ 120	$ 1,664	(93)%
Seismic	1,081	1,761	(39)%	127	878	(86)%
Drilling and completions	25,130	16,801	50%	5,758	5,783	0%
Capitalized G&A	1,627	865	88%	395	288	37%
Gas gathering systems	247	7	3,429%	_	35	(99)%
Total operations	$ 32,907	$ 23,171	42%	$ 6,400	$ 8,648	(26)%
Property acquisitions (dispositions)	(30,874)	60,593	(151)%	Nil	Nil	n/a
Well site facilities inventory	(165)	401	(141)%	(206)	(895)	(77)%
Office equipment	136	72	89%	39	15	160%
Total (net of acquisitions and dispositions)	$ 2,004	$ 84,237	(98)%	$ 6,233	$ 7,768	(20)%

Capital expenditures for operations increased for the year ended December 31, 2006 over 2005 as Rock drilled the same number of gross wells (33) but more net wells (28.3 in 2006 versus 22.4 in 2005) as the Company gained more control over its operations. The Company participated in more West Central core area operations, including re-completions and, as a result, drilling and completions costs increased by 50 percent. In total Rock participated in nine (6.1 net) re-completions, which included one (0.8 net) natural gas well in the Musreau area which is expected to be tied-in in the fourth quarter of 2007, when third-party facilities are expanded, and one (1.0 net) oil well at Medicine River, which was brought on-production in the fourth quarter of 2006.

Land expenditures increased as the Company continued to build its West Central core area presence. Seismic expenditures decreased as the number of programs shot in the Plains core area decreased with Rock's shift to the West Central core area. Total net capital expenditures were reduced to $2 million in 2006 from $84 million in 2005 as the proceeds from the Company's asset rationalization program essentially offset capital expenditures from operations. In 2005 the Company completed the ELM/Optimum/Qwest acquisitions which significantly increased total capital expenditures.

During 2006, Rock drilled 27 (27.0 net) operated wells and six (1.3 net) non-operated wells, achieving a 96 percent success rate, compared to 20 (20.0 net) operated wells and 13 (2.1 net) non-operated wells and an 82 percent success rate in 2005. In the Plains core area Rock drilled 25 (25.0 net) heavy oil wells and one (1.0 net) dry hole. All of the wells were operated and all successful wells were on-production at year end except four (4.0 net) wells drilled in December 2006, which were brought on-production in the first quarter of 2007. Rock had no production from the Plains area at the beginning of 2005 and exited with approximately 670 boe per day in 2005 and 1,250 boe per day in 2006. In the West Central Alberta core area in 2006 Rock drilled two (0.9 net) oil wells in the Niton area, three (1.2 net) natural gas wells and one (0.1 net) dry hole. Of the three gas wells two (1.1 net) were drilled in the Musreau area and are expected to be tied-in in the fourth quarter of 2007 along with the re-completed well. In aggregate the Musreau-area wells are projected to initially increase Rock's production by 300 boe per day once tied-in. For the fourth quarter of 2006 capital expenditures decreased by approximately $2 million from 2005 levels as land and seismic activity decreased in the quarter.

LIQUIDITY AND CAPITAL RESOURCES

Rock's current approved capital budget for 2007 projects spending of $20 million. In 2007 funds from operations are expected to be approximately $15 million. The capital spending in excess of cash flow is intended to be funded through bank debt. Subsequent to year-end the Company arranged a new $23 million bank facility with a different chartered bank to replace its existing bank facility. With year-end debt of $12.6 million Rock has room to fund the $5 million of capital expenditures in excess of expected cash flow for 2007. The new bank facility will be reviewed by April 30, 2007 with the Company's 2006 independent reserve report. Based on the drilling in the fourth quarter of 2006, Rock expects, subject to any changes to the bank's commodity price forecast, an increase to the borrowing base. The Company will continue to monitor capital expenditures, cash flow from operations and debt levels and make adjustments, in order to ensure the projected debt to cash flow ratio does not exceed 1.5:1.

The Company has a demand operating loan facility with a Canadian chartered bank. This facility was put in place subsequent to year-end with a new lender and the Company's previous facility was repaid. The new facility is subject to the bank's valuation of the Company's oil and natural gas assets and the credit currently available is $23 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 un-drawn 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 facility is currently under its annual review. As at March 15, 2007 approximately $14.7 million was drawn under the facility.

SELECTED ANNUAL DATA

The following table provides selected annual information for Rock. The Company changed its year-end at December 31, 2004 from March 31, 2004. In order to make comparisons of periods compatible, information presented for the 12-month period ended December 31, 2004 has been compiled by combining the nine-month period ended December 31, 2004 with the three-month period ended March 31, 2004.

	12 Months Ended 12/31/06	12 Months Ended 12/31/05	12 Months Ended 12/31/04
Production *(boe/d)*	2,098	1,122	181
Oil and natural gas revenues ($000)	$ 33,156	$ 22,873	$ 2,845
Average realized price *($/boe)*	$43.27	$ 55.85	$ 43.02
Royalties *($/boe)*	$8.98	$ 12.28	$ 9.89
Operating expense *($/boe)*	$12.08	$ 11.59	$ 7.97
Operating netback *($/boe)*	$22.21	$ 31.98	$ 25.16
Net G&A expense ($000)	$2,278	$ 1,411	$ 959
Stock-based compensation ($000)	$ 1,188	$ 485	$ 202
Funds from operations ($000)	$ 13,867	$ 11,433	$ 1,218
Per share – basic	$0.71	$ 0.74	$ 0.14
Per share – diluted	$0.71	$ 0.74	$ 0.14
Net income (loss)	($884)	$ 1,510	$ 571
Per share – basic	($0.05)	$ 0.10	$ 0.06
Per share – diluted	($0.05)	$ 0.10	$ 0.06
	As at 12/31/06	As at 12/31/05	As at 12/31/04
Total assets	$ 85,306	$ 99,604	$ 25,057
Total liabilities	$ 24,827	$ 39,385	$ 2,693

SELECTED QUARTERLY DATA

The following table provides selected quarterly information for Rock:

	3 Months Ended 12/31/06	3 Months Ended 09/30/06	3 Months Ended 06/30/06	3 Months Ended 03/31/06	3 Months Ended 12/31/05	3 Months Ended 09/30/05	3 Months Ended 06/30/05	3 Months Ended 03/31/05
Production *(boe/d)*	2,004	1,613	2,190	2,594	2,120	1,343	693	309
Oil and natural gas revenues ($000)	$ 7,535	$ 7,023	$ 8,774	$ 9,824	$ 11,760	$ 7,030	$ 2,924	$ 1,159
Average realized price *($/boe)*	$40.73	$47.30	$44.01	$42.08	$60.29	$56.90	$46.36	$41.65
Royalties *($/boe)*	$7.88	$5.27	$8.97	$12.26	$13.67	$11.61	$10.39	$9.73
Operating expense *($/boe)*	$13.63	$13.13	$10.55	$11.55	$11.83	$13.19	$8.62	$9.49
Operating netback *($/boe)*	$19.22	$28.90	$24.49	$18.27	$34.79	$32.10	$27.35	$22.43
Net G&A expense *($000)*	$ 690	$ 477	$ 462	$ 649	$ 526	$ 329	$ 282	$ 274
Stock-based compensation *($000)*	$ 295	$ 308	$ 305	$ 280	$ 257	$ 131	$ 55	$ 42
Funds from operations *($000)*	$ 2,644	$ 3,791	$ 4,028	$ 3,404	$ 6,020	$ 3,552	$ 1,469	$ 392
Per share – basic	$0.13	$ 0.19	$ 0.21	$ 0.17	$ 0.31	$ 0.18	$ 0.11	$ 0.04
Per share – diluted	$0.13	$ 0.19	$ 0.21	$ 0.17	$ 0.31	$ 0.18	$ 0.11	$ 0.04
Net income (loss) *($000)*	($119)	$ 891	($ 583)	($ 1,074)	$ 747	$ 634	$ 77	$ 51
Per share – basic	($0.01)	$ 0.05	($ 0.03)	($ 0.05)	$ 0.04	$ 0.03	$ 0.01	$ 0.01
Per share – diluted	($0.01)	$ 0.05	($ 0.03)	($ 0.05)	$ 0.04	$ 0.03	$ 0.01	$ 0.01
Capital expenditures *($000)*	$ 6,223	$ 12,520	$ 4,397	$ 9,728	$ 7,768	$ 7,920	$ 66,411	$ 2,138
	As at 12/31/06	As at 09/30/06	As at 06/30/06	As at 03/31/06	As at 12/31/05	As at 09/30/05	As at 06/30/05	As at 03/31/05
Working capital *($000)*	($12,580)	($8,990)	($31,135)	($30,766)	($24,442)	($22,643)	($18,093)	$10,297

Production has grown over the last two quarters of 2006 subsequent to the asset rationalization program which was completed in the third quarter of 2006. Immediately following these dispositions Rock's production was approximately 1,400 boe per day. Production growth has primarily come from drilling operations in the Plains core area and well recompletions at the Medicine River property near Sylvan Lake. Over the same period corporate average product prices have decreased as natural gas and oil prices declined. Heavy oil prices decreased in the fourth quarter, as expected, due to seasonality but in general were higher than 2005 levels. Royalty rates have generally improved in 2006 as Rock's product mix became more heavily weighted to oil, which usually has a lower royalty rate than gas, and because of Rock receiving the ARTC benefit.

Operating costs per boe have fluctuated depending on the amount of heavy oil start-up operations in any particular period, and the fourth quarter of 2006 included $200,000 relating to 2005 gas processing cost adjustments. Without these costs fourth quarter operating costs per boe would have decreased to $12.57 per boe. Field netbacks generally declined in 2006 from 2005 due to lower product prices. G&A expenses continued to rise as staffing levels increased throughout the period as the Company's activity levels grew. Funds from operations and net income or loss have been primarily affected by the change in product prices as changes in operating costs and royalty rates tended to offset each other. Net capital expenditures were significantly impacted by the asset rationalization program in the third quarter of 2006, which generated proceeds of $30.9 million, and by the acquisitions in the second quarter of 2005, which incurred costs of $60.5 million. The second quarter of the year tends to be a slower operational period with respect to capital investments due to the effects of spring break-up.

Reserves

Rock's reserves have been independently evaluated by GLJ Petroleum Consultants Ltd. (GLJ) at year-end 2006. This is the third year in which GLJ has evaluated the Company's reserves. The reserves as at December 31, 2006 and 2005 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 2005 and year-end 2006. NI 51-101 requires reserves to be reconciled on a net basis (after deducting royalties but including any royalty interests) ("net interest"). In addition, in the tables below Rock has also provided a reserve reconciliation on a gross basis (before deducting royalties and without including any royalty interest) ("gross interest").

Rock's gross interest reserves at year-end 2006 are 4.4 million boe of proved reserves and 7.3 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 2.0 million boe of proved reserves and 3.6 million boe of proved plus probable reserves.

RESERVES RECONCILIATION

The following table is a reconciliation of Rock's gross interest reserves at December 31, 2006 using GLJ's forecast pricing and cost estimates as at December 31, 2006.

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

	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, 2005	331	427	111	146	1,128	2,096	14,427	19,657	3,974	5,946
Additions(1)	121	197	22	53	1,734	2,500	1,825	5,240	2,181	3,624
Technical revisions(2)	36	41	8	6	132	(8)	(218)	(613)	140	(65)
Acquisitions	0	0	0	0	0	0	0	0	0	0
Dispositions	(10)	(12)	(1)	(1)	0	0	(6,186)	(8,358)	(1,042)	(1,406)
Production	(65)	(65)	(21)	(21)	(289)	(289)	(2,342)	(2,342)	(765)	(765)
December 31, 2006	413	588	118	183	2,705	4,299	7,506	13,584	4,488	7,334

(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.

The following table is a reconciliation of Rock's net interest reserves at December 31, 2006 using GLJ's forecast pricing and cost estimates as at December 31, 2006.

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

	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, 2005	286	371	78	102	926	1,712	10,648	14,608	3,065	4,621
Additions(1)	88	144	17	39	1,397	2,010	1,531	4,192	1,757	2,891
Technical revisions(2)	17	22	7	4	144	27	(234)	(570)	128	(43)
Acquisitions	0	0	0	0	0	0	0	0	0	0
Dispositions	(8)	(8)	0	0	0	0	(4,406)	(5,924)	(742)	(995)
Production	(30)	(30)	(18)	(18)	(260)	(260)	(1,588)	(1,588)	(572)	(572)
December 31, 2006	353	499	84	128	2,207	3,489	5,951	10,719	3,636	5,902

(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.

RESERVES AND NET PRESENT VALUE (FORECAST PRICES AND COSTS)

The following tables summarize Rock's remaining oil and natural gas reserve volumes along with the value of future net revenue utilizing GLJ's forecast pricing and cost estimates as at December 31, 2006.

Reserves

Reserves Category	Oil Gross (mbbl)	Oil Net (mbbl)	NGL Gross (mbbl)	NGL Net (mbbl)	Heavy Oil Gross (mbbl)	Heavy Oil Net (mbbl)	Natural Gas Gross (mmcf)	Natural Gas Net (mmcf)
Proved								
Proved Producing	371	315	101	72	2,180	1,788	4,909	3,790
Proved Non-Producing	42	38	18	12	106	84	2,250	1,910
Proved Undeveloped	0	0	0	0	419	335	348	251
Total Proved	413	353	119	84	2,705	2,207	7,507	5,951
Probable Additional	175	145	63	44	1,594	1,282	6,084	4,768
Total Proved Plus Probable	588	499	183	128	4,299	3,489	13,591	10,719

Note: Figures may not add due to rounding.

Net Present Value of Future Net Revenue

	Before Income Taxes					After Income Taxes				
	Discounted at (% per year)					Discounted at (% per year)				
Reserves Category	0	5	10	15	20	0	5	10	15	20
Proved										
Proved Producing	78,425	67,396	59,563	53,638	48,959	70,150	60,789	54,048	48,909	44,829
Proved Non-Producing	12,887	10,303	8,588	7,345	6,395	8,729	6,839	5,601	4,715	4,044
Proved Undeveloped	5,665	4,925	4,307	3,786	3,343	3,717	3,112	2,626	2,229	1,899
Total Proved	96,977	82,624	72,457	64,769	58,697	82,596	70,740	62,276	55,853	50,773
Probable Additional	60,052	43,397	33,231	26,839	21,486	40,801	29,124	21,982	17,718	13,744
Total Proved Plus Probable	157,029	126,021	105,688	91,158	80,183	123,397	99,864	84,257	73,031	64,517

Note: Figures may not add due to rounding.

RESERVES AND NET PRESENT VALUE (CONSTANT PRICES AND COSTS)

The following tables summarize Rock's remaining oil and natural gas reserves along with the value of future net revenue utilizing GLJ's constant pricing and costs estimates. Pricing was based on benchmark reference prices posted at or near December 31, 2006 with adjustments for oil differential and natural gas heating values applied to arrive at a company average. Capital and operating costs were not inflated.

Reserves

	Oil		NGL		Heavy Oil		Natural Gas	
Reserves Category	Gross (mbbl)	Net (mbbl)	Gross (mbbl)	Net (mbbl)	Gross (mbbl)	Net (mbbl)	Gross (mmcf)	Net (mmcf)
Proved								
Proved Producing	375	319	101	71	2,180	1,790	4,928	3,804
Proved Non-Producing	42	38	18	12	106	84	2,238	1,939
Proved Undeveloped	0	0	0	0	419	335	348	254
Total Proved	417	357	119	84	2,705	2,209	7,514	5,996
Probable Additional	175	146	63	44	1,594	1,284	6,026	4,713
Total Proved Plus Probable	592	503	182	128	4,299	3,493	13,540	10,709

Note: Figures may not add due to rounding.

Net Present Value of Future Net Revenue

	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	72,077	62,251	55,181	49,783	45,492	65,890	57,307	51,063	46,266	42,436
Proved Non-Producing	9,858	8,027	6,739	5,775	5,024	6,657	5,297	4,353	3,657	3,122
Proved Undeveloped	5,131	4,447	3,875	3,393	2,983	3,365	2,796	2,340	1,968	1,659
Total Proved	87,067	74,726	65,795	58,951	53,500	75,912	65,400	57,757	51,891	47,218
Probable Additional	48,533	35,925	27,897	22,330	18,256	32,952	24,026	18,341	14,407	11,536
Total Proved Plus Probable	135,600	110,651	93,693	81,281	71,756	108,864	89,425	76,098	66,298	58,753

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 Constant Prices and Costs evaluation and the Forecast Prices and Costs evaluation.

Summary of Pricing and Cost Rate Assumptions at December 31, 2006 – Constant Prices and Costs

	Edmonton Par Oil Price 40 API (Cdn$/bbl)	AECO Gas Price (Cdn$/mcf	Edmonton Pentane (Cdn$/bbl)	Edmonton Propane (Cdn$/bbl)	Edmonton Butane (Cdn$/bbl)	Spec Ethane (Cdn$/bbl)	EXCHANGE RATE (US$/Cdn$)
	67.58	6.07	71.55	43.25	54.06	20.43	0.8581

Summary of Pricing and Cost Rate Assumptions at December 31, 2006 – Forecast Prices and Costs

	Oil				NGL			Natural Gas			
Year	WTI Cushing (US$/bbl)	Edmonton Reference Price ($/bbl)	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)
2007	62.00	70.25	61.25	39.25	45.00	56.25	71.75	24.25	7.20	0.87	2
2008	60.00	68.00	59.25	40.00	43.50	50.25	69.25	25.25	7.45	0.87	2
2009	58.00	65.75	57.25	39.75	42.00	48.75	67.00	26.25	7.75	0.87	2
2010	57.00	64.50	56.00	39.75	41.25	47.75	65.75	26.50	7.80	0.87	2
2011	57.00	64.50	56.00	40.25	41.25	47.75	65.75	26.50	7.85	0.87	2
2012	57.50	65.00	56.50	41.50	41.50	48.00	66.25	27.75	8.15	0.87	2
2013	58.50	66.25	57.75	42.50	42.50	49.00	67.50	28.25	8.30	0.87	2
2014	59.75	67.75	59.00	43.50	43.25	50.25	69.00	29.00	8.50	0.87	2
2015	61.00	69.00	60.00	44.25	44.25	51.00	70.50	29.50	8.70	0.87	2
2016	62.25	70.50	61.25	45.25	45.00	52.25	72.00	30.00	8.90	0.87	2
2017	63.50	71.75	62.50	46.00	46.00	53.00	73.25	30.75	9.10	0.87	2
2018+	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	0.87	2

FINDING, DEVELOPMENT AND ACQUISITION COSTS

The following table summarizes Rock's finding, development and acquisition costs for the years ended December 31, 2006 and 2005 and the nine months ended 2004, including future development costs. Due to the change in the Company's year-end in 2004 only nine-month data is shown for finding and development costs for 2004, given the availability of independent reserve information for that period.

	12 months ended Dec. 31, 2006	12 months ended Dec. 31, 2005	9 months ended Dec. 31, 2004	Period Cumulative Total
Oil and Natural Gas Operations:				
Proved finding and development costs				
Capital expenditures[1] *($000)*	$32,907	$22,912	$5,876	$61,695
Future capital costs *($000)*	2,939	962	1,174	5,075
Total capital *($000)*	$35,846	$23,874	$7,050	$66,877
Reserve additions[2] *(mboe)*	2,181	1,188	294	6,663
Proved finding and development costs *($/boe)*	$16.44	$20.10	$23.98	$18.23
Proved Plus Probable finding and development costs				
Capital expenditures[1] *($000)*	$32,907	$22,912	$5,876	$61,695
Future capital costs *($000)*	7,986	3,900	$3,051	$14,937
Total capital *($000)*	$40,893	$26,812	$8,927	$76,739
Reserve additions[2] *(mboe)*	3,624	2,201	551	6,376
Proved Plus Probable finding and development costs *($/boe)*	$11.28	$12.18	$16.20	$12.02
Acquisitions/Dispositions:				
Proved finding and development costs – Acquisitions (Dispositions)				
Capital expenditures[1] *($000)*	($30,878)	$60,853	-	$29,975
Future capital costs *($000)*	(2,400)	3,647	-	1,247
Total capital *($000)*	($33,278)	$64,500	-	$31,222
Reserve additions *(mboe)*	(1,042)	2,397	-	1,355
Proved finding and development costs *($/boe)*	($31.94)	$26.91	-	$23.04
Proved Plus Probable finding and development costs – Acquisitions (Dispositions)				
Capital expenditures[1] *($000)*	($30,878)	$60,853	-	$29,975
Future capital costs *($000)*	(2,400)	3,733	-	1,333
Total capital *($000)*	($33,278)	$64,586	-	$31,308
Reserve additions *(mboe)*	(1,406)	3,154		
Proved + Probable finding and development costs *($/boe)*	($23.67)	$20.48	-	$17.91
Total Activities:				
Proved finding and development costs				
Capital expenditures[1] *($000)*	$2,029	$83,765	$5,876	$91,670
Future capital costs *($000)*	539	4,609	1,174	6,322
Total capital *($000)*	$2,568	$88,374	$7,050	$98,099
Reserve additions[3] *(mboe)*	1,279	3,620	273	5,172
Total Proved finding and development costs *($/boe)*	$2.01	$24.41	$25.82	$18.95
Proved Plus Probable finding and development costs				
Capital expenditures[1] *($000)*	$2,029	$83,765	$5,876	$91,670
Future capital costs *($000)*	5,586	7,633	3,051	16,270
Total capital *($000)*	$7,615	$91,398	$8,927	$108,047
Reserve additions[3] *(mboe)*	2,153	5,284	422	7,859
Total Proved Plus Probable finding and development costs *($/boe)*	$3.54	$17.30	$21.15	$13.73

[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 and development 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. Finding and development costs on operations improved in 2006 compared to 2005 and 2004 primarily as Rock's grassroots exploration and development program gained momentum. Capital costs on operations for 2005 and 2004 included a relatively high land and seismic component, 23 percent and 48 percent of expenditures respectively, which increased finding and development costs.

Rock's 2007 capital budget has approximately 25 percent of the spending allocated to land and seismic as the Company continues to build its grassroots program, particularly in the West Central Alberta core area. Finding and development costs on the acquired properties are based on the reserve evaluation as at December 31, 2005 and were increased by the amount of production from the closing date to December 31, 2005 to provide an estimate of the reserves purchased. Finding and development 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. Finding and development costs for total activities include operations, acquisitions, dispositions and reserve revisions.

LAND HOLDINGS

The following table summarizes Rock's land holdings as at December 31, 2006 and 2005:

(acres)		Dec. 31, 2006	Dec. 31, 2005	Change
Developed	– Gross	63,085	79,188	(20)%
	– Net	23,566	31,378	(25)%
Undeveloped	– Gross	76,030	79,666	(5)%
	– Net	39,429	36,898	7%
Total	– Gross	139,115	158,854	(12)%
	– Net	62,995	68,276	(8)%

NET ASSET VALUE

The following table summarizes Rock's net asset value and net asset value per share as at December 31, 2006 and December 31, 2005:

($000 except number of shares and net asset value per share)	December 31, 2006	December 31, 2005	Change
Proved plus probable reserves[1]	105,688	87,315	21%
Undeveloped land[2]	8,220	8,448	(3)%
Seismic[3]	3,550	2,617	36%
Working capital including debt	(12,580)	(24,442)	49%
Option proceeds	7,405	5,053	47%
Net Asset Value (Diluted)	112,283	78,991	42%
Diluted shares *(000)*	21,405	20,758	3%
Net asset value per share	$5.25	$3.81	38%

[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 2006 and 2005 forecast pricing and costs estimates and using a discount rate ot 10 percent.

[2] 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.

[3] Seismic value is based on actual cost of seismic acquired or purchased.

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:

	2007	2008	2009	2010	2011
Office premise leases	$ 676	$ 895	$ 828	$ 828	$ 828
Demand bank loan(1)	$10,965				

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

OUTSTANDING SHARE DATA

At December 31, 2006 and to date, Rock had 19,637,321 common shares outstanding. At December 31, 2006 the Company had 1,767,277 stock options outstanding with an average exercise price of $4.19 per share.

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 Chief Executive Officer and the Chief Financial Officer have evaluated the effectiveness of the disclosure controls and procedures as at December 31, 2006 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, 2006. 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

There has been no change in accounting policies since the Company's last fiscal year-end.

NEW ACCOUNTING PRONOUNCEMENTS

Comprehensive Income

The Canadian Institute of Chartered Accountants (CICA) issued CICA Handbook section 1530, Comprehensive Income. The section is effective for fiscal years beginning on or after October 1, 2006. It describes how to report and disclose comprehensive income and its components. An integral part of the accounting standards on recognition and measurement of financial instruments is the ability to present certain gains and losses outside net income, in other comprehensive income. This standard requires that a company present comprehensive income and its components in a financial statement displayed with the same prominence as other financial statements that constitute a complete set of financial statements, in both annual and interim financial statements.

The CICA also made changes to CICA Handbook section 3250, Surplus, and reissued it as section 3251, Equity. The section is also effective for fiscal years beginning on or after October 1, 2006. The changes in how to report and disclose equity and changes in equity are consistent with the new requirements of section 1530, Comprehensive Income.

Rock will adopt this section effective January 1, 2007 but the Company does not expect this section to have a material impact on its consolidated financial statements.

Financial Instruments – Recognition and Measurement

The CICA issued CICA Handbook section 3855, Financial Instruments – Recognition and Measurement. The section is effective for fiscal years beginning on or after October 1, 2006. It describes the standards for recognizing and measuring financial assets, financial liabilities and non-financial derivatives. This section requires that all financial assets be measured at fair value, with some exceptions; all financial liabilities be measured at fair value if they are derivatives or classified as held for trading purposes (other financial liabilities are measured at their carrying value); and all derivative financial instruments be measured at fair value, even when they are part of a hedging relationship.

Rock will adopt this section effective January 1, 2007 but does not expect this section to have a material impact on its consolidated financial statements.

Hedges

The CICA issued CICA Handbook section 3865, Hedges. The section is effective for fiscal years beginning on or after October 1, 2006, and describes when and how hedge accounting can be used. Hedging is an activity used by a company to change an exposure to one or more risks by creating an offset between changes in the fair value of a hedged item and a hedging item; changes in the cash flows attributable to a hedged item and a hedging item; or changes resulting from a risk exposure relating to a hedged item and a hedging item. Hedge accounting ensures that all gains, losses, revenues and expenses from the derivative and the item it hedges are recorded in the income statement in the same period.

Rock will adopt this section effective January 1, 2007 but does not expect this section to have a material impact on its consolidated financial statements.

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 judgments 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 judgment 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. Judgments 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 were 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 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 high activity levels the industry has been experiencing, 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.

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 1800, 700 - 9th Avenue S.W., Calgary, Alberta, T2P 3V4.

Consolidated Balance Sheets
(000s of dollars)

As at	December 31, 2006	December 31, 2005
Assets		
Current assets		
Cash and cash equivalents	$ -	$ 145
Accounts receivable	4,753	7,093
Prepaid expenses	532	385
	5,285	7,623
Property, plant and equipment *(note 4)*	97,229	95,271
Accumulated depletion and depreciation	(22,882)	(8,893)
	74,347	86,378
Goodwill	5,748	5,602
	$ 85,380	$ 99,603
Liabilities and Shareholders' Equity		
Current liabilities		
Accounts payable and accrued liabilities	$ 6,900	$ 9,090
Bank debt *(note 5)*	10,965	22,976
	17,865	32,066
Future tax liability *(note 9)*	4,942	5,204
Asset retirement obligation *(note 6)*	2,094	2,115
Shareholders' equity		
Share capital *(note 7)*	57,326	57,369
Contributed surplus *(note 8)*	1,641	453
Retained earnings	1,512	2,396
	60,479	60,218
Commitments *(note 11)*		
Subsequent event (note 12)		
	$ 85,380	$ 99,603

See accompanying notes to consolidated financial statements.

Approved by the Board:

Consolidated Statements of Operations and Retained Earnings

(000s of dollars, except per share amounts)

Years ended	December 31, 2006	December 31, 2005
Revenues:		
Oil and natural gas revenue	$ 33,156	$ 22,873
Royalties, net of Alberta Royalty Tax Credit	(6,881)	(5,027)
Other income	198	317
	26,473	18,163
Expenses:		
General and administrative	2,278	1,411
Operating	9,255	4,745
Interest	924	457
Stock-based compensation *(note 8)*	1,188	485
Depletion, depreciation, and accretion	14,118	8,287
	27,763	15,385
Income (loss) before income taxes	(1,290)	2,778
Income taxes		
Current *(note 9)*	45	73
Future income taxes (reduction) *(note 9)*	(451)	1,196
Net income (loss) for the year	(884)	1,509
Retained earnings, beginning of year	2,396	887
Retained earnings, end of year	$ 1,512	$ 2,396
Diluted and basic net income (loss) per share *(note 7)*	$ (0.05)	$ 0.10

See accompanying notes to consolidated financial statements.

Consolidated Statements of Cash Flows
(000s of dollars)

Years ended	December 31, 2006	December 31, 2005
Cash provided by (used in):		
Operating:		
Net income (loss) for the year	$ (884)	$ 1,509
Add: Non-cash items:		
Depletion, depreciation, and accretion	14,118	8,287
Actual abandonment costs	(104)	(44)
Stock-based compensation	1,188	485
Future income taxes (reduction)	(451)	1,196
	13,867	11,433
Changes in non-cash working capital	2,571	(4,319)
	16,438	7,114
Financing:		
Issuance of common shares	-	217
Bank debt	(12,011)	22,976
Repurchase of stock options	-	(185)
	(12,011)	23,008
Investing:		
Property, plant and equipment	(32,879)	(23,644)
Acquisition of property, plant and equipment *(note 3)*	-	(23,880)
Disposition of property, plant and equipment	30,874	-
Changes in non-cash working capital	(2,567)	8,915
	(4,572)	(38,609)
Decrease in cash and cash equivalents	(145)	(8,487)
Cash and cash equivalents, beginning of year	145	8,632
Cash and cash equivalents, end of year	$ -	$ 145
Interest and taxes paid and received:		
Interest paid	960	428
Interest received	32	42
Taxes paid	$ 25	$ 57

See accompanying notes to consolidated financial statements.

Notes to Consolidated Financial Statements

Years ended December 31, 2006 and 2005

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 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. The Company follows the Canadian accounting standard relating to stock-based compensation and other stock-based payments as it applies to other stock-based compensation granted to employees, officers and directors. Under this standard, future 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 and the amounts used for ceiling test calculations are based on estimates of reserves, future costs and timing. 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. Acquisition of ELM/Optimum/Qwest

On March 14, 2005 the Company agreed to acquire, in two separate closings from 14 different entities (six private companies and eight drilling fund partnerships), petroleum and natural gas properties mainly through their various subsidiary companies. The transactions have been accounted for using the purchase method with the results of operations for each transaction included in the financial statements from the date of acquisition.

The first closing of the ELM/Optimum/Qwest properties occurred on April 7, 2005. The Company purchased all of the outstanding shares of 1143734 Alberta Ltd. and assets were purchased directly from three private entities and four drilling fund partnerships. The final purchase price equation is as follows:

($000)

Property, plant and equipment	$ 16,483
Note payable*	(309)
Asset retirement obligation	(373)
	$ 15,801
Consideration provided:	
Cash	$ 4,575
Common shares (3,091,483)	10,944
Transaction costs	282
	$ 15,801

** Paid to vendors on final adjustments*

The second closing of the ELM/Optimum/Qwest properties occurred on June 17, 2005. The Company purchased all of the outstanding shares of 1156168 Alberta Ltd., 1159203 Alberta Ltd. and 1140511 Alberta Ltd. The purchase price equation is as follows:

($000)

Property, plant and equipment	$ 45,490
Note receivable*	148
Goodwill	4,593
Future income taxes	(4,593)
Asset retirement obligation	(1,007)
	$ 44,631
Consideration provided:	
Cash	$ 18,504
Common shares (7,234,005)	25,609
Transaction costs	518
	$ 44,631

** Paid by vendors on final adjustments*

The purchase price allocations for both transactions were initially based on estimates of the fair values of the assets and liabilities as of the closing date, purchase price adjustments, transaction costs and holdback amounts.

4. Property, Plant and Equipment

($000)	December 31, 2006	December 31, 2005
Petroleum and natural gas properties	$ 96,887	$ 95,160
Other assets	342	111
	97,229	95,271
Accumulated depletion and depreciation	(22,882)	(8,893)
	$ 74,347	$ 86,378

In the third quarter of 2006, the Company disposed of four non-operated producing properties for total proceeds of approximately $30.9 million. The properties disposed of included Wild River, Highland/Hudson and Chestermere. As the change in the depletion rate was less than 20 percent, no gain has been booked into the financial statements.

At December 31, 2006, petroleum and natural gas properties included $8,220, (December 31, 2005 – $6,265 of unproved property costs which have been excluded from the depletable base.

During the year ended December 31, 2006, $1,627 (Year ended December 31, 2005 – $865) of administrative costs relating to exploration and development activities were capitalized as part of property, plant and equipment.

At December 31, 2006, 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$/mmbtu)	Heavy Oil at Hardesty (12° API) (CDn$/bbl)	Currency exchange rate (US$/CDN$)
2007	62.00	70.25	7.20	39.25	0.87
2008	60.00	68.00	7.45	40.00	0.87
2009	58.00	65.75	7.75	39.75	0.87
2010	57.00	64.50	7.80	39.75	0.87
2011	57.00	64.50	7.85	40.25	0.87
2012	57.50	65.00	8.15	41.50	0.87
2013	58.50	66.25	8.30	42.50	0.87
2014	59.75	67.75	8.50	43.50	0.87
2015	61.00	69.00	8.70	44.25	0.87
2016	62.25	70.50	8.90	45.25	0.87
2017	63.50	71.75	9.10	46.00	0.87
Thereafter (escalation)	2.0%/yr	2.0%/yr	2.0%/yr	2.0%/yr	0.87

5. Bank Debt

At December 31, 2006 the Company has 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 current limit under the facility is $18 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. The facility also bears a standby charge for un-drawn amounts. The facility was replaced in March 2007 (see note 12, Subsequent Event).

6. 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, 2006 is approximately $3,666 (December 31, 2005 – $3,385), which will be incurred between 2007 and 2019. 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.

A reconciliation of the asset retirement obligations is provided below:

	December 31, 2006	December 31, 2005
Balance, beginning of year	$ 2,115	$ 500
Liabilities incurred/acquired during year	413	1,583
Dispositions	(459)	-
Accretion	129	76
Actual retirement costs	(104)	(44)
Balance, end of year	$ 2,094	$ 2,115

7. 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, 2004	9,259,453	$ 21,276
Redemption *(i)*	(448)	(2)
Future tax effect of flow-through share renouncements *(ii)*		(723)
Issued for property acquisitions	10,325,488	36,552
Issued for flow-through shares *(iii)*	22,263	115
Issued for stock options exercised	30,565	151
Issued and outstanding as at December 31, 2005	19,637,321	$ 57,369
Future tax effect of flow-through share renouncements *(iii)*	-	(43)
Issued and outstanding as at December 31, 2006	19,637,321	$ 57,326

(i) In accordance with the terms of the 30-for-1 share consolidation shareholders holding 1,000 or fewer pre-consolidated common shares redeemed their shares for cash based on the value of $0.1129 per pre-consolidated share.

(ii) The Company has renounced resource expenditures on flow-through shares issued by predecessor companies. At March 31, 2004, the Company was committed to spending $1.8 million on drilling and exploration activities on or before January 31, 2005 to satisfy flow-through share commitments. At December 31, 2004, all required expenditures had been made and the Company completed the renouncements in February 2005.

(iii) 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.

As at December 31, 2006 and 2005 no preference shares were outstanding.

(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 expire 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, 2006 and December 31, 2005 and changes during the year ended on those dates:

	December 31, 2006		December 31, 2005	
	Options	**Weighted-Average Exercise Price ($)**	Options	Weighted-Average Exercise Price ($)
Outstanding, beginning of year	1,120,332	$4.51	532,387	$ 3.49
Granted	677,779	$3.66	777,944	$ 4.95
Exercised	-	-	(135,629)	$ 3.39
Forfeited	-	-	(54,370)	$ 3.58
Expired	(30,834)	$3.87	-	-
Outstanding, end of year	1,767,277	$4.19	1,120,332	$ 4.51

Options outstanding and exercisable under the stock option plan are summarized below as at December 31, 2006:

	Outstanding Options			Exercisable Options	
	Number of Options	Weighted-Average Exercise Price	Weighted-Average Years to Expiry	Number of Options	Weighted-Average Exercise Price ($)
$ 3.15 - $ 3.90	754,333	$ 3.30	1.83	155,777	$ 3.47
$ 4.00 - $ 5.11	1,012,944	$ 4.86	1.76	217,667	$ 4.93
	1,767,277	$ 4.19	1.79	373,444	$ 4.32

(D) PER SHARE AMOUNTS

The weighted average number of common shares outstanding during the year ended December 31, 2006 of 19,637,321 (year ended December 31, 2005 – 15,436,835) 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, 2006. As at December 31, 2006, an additional 17,660 (December 31, 2005 – 64,127) common shares were used to calculate diluted earnings per share.

8. 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, 2006 was estimated to be $976 (year ended December 31, 2005 – $1,658) as at the grant date using the Black-Scholes option pricing model and the following assumptions:

Risk-free interest rate	4.00% - 6.00%
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, 2006	December 31, 2005
Balance, beginning of year	$ 453	$ 202
Stock-based compensation expense	1,188	485
Net benefit on options exercised[1]	-	(234)
Balance, end of year	$ 1,641	$ 453

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

9. 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 33.70 percent (December 31, 2005 – 37.62 percent). The principal reasons for differences between such "expected" income tax expense and the amount actually recorded are as follows:

	December 31, 2006	December 31, 2005
Net income before income taxes	$ (1,290)	$ 2,778
Statutory income tax rate	33.7%	37.62%
Expected income taxes	$ (435)	$ 1,045
Add (deduct):		
Stock-based compensation	400	182
Non-deductible Crown charges	330	1,038
Change in enacted rates	(311)	-
Other	180	19
Resource allowance	(615)	(888)
Acquisition	-	12,133
Change in valuation allowance	-	(12,333)
Provision for income taxes	$ (451)	$ 1,196
Capital tax	45	73
Provision for (recovery of) income taxes	$ (406)	$ 1,269

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, 2006	December 31, 2005
Loss carry-forwards	$ 4,941	$ 9,097
Property, plant and equipment	(6,218)	(11,542)
Non-coterminous year-ends	(3,859)	(3,049)
Share issuance costs	263	360
Asset retirement obligation	649	719
Calculated future income tax liability	(4,224)	(4,415)
Valuation allowance	(718)	(789)
Future income taxes (liability)	$ (4,942)	$ (5,204)

At December 31, 2006, Rock and its subsidiary have tax pools aggregating $69.0 million prior to the allocation of deferred partnership income and $55.2 million (December 31, 2005 – $65.5 million) after the allocation of deferred partnership income. The non-capital losses prior to the allocation of deferred partnership income expire as follows:

2011	$ 479
2026	13,656
	$ 14,135

10. 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.

11. Commitments

Obligations with a fixed term are as follows:

		2007	2008	2009	2010	2011
Lease of office premises	$ 676	$ 895	$ 828	$ 828	$ 828	

12. Subsequent Event

Subsequent to year-end the Company entered into a new demand operating facility with a different Canadian chartered bank. The new facility has a borrowing limit of $23 million, up from the current limit of $18 million. The new loan is based on the Company's 2005 reserve report by GLJ Petroleum Consultants Ltd. (GLJ) and internal estimates at September 30, 2006. The new facility will be reviewed before April 30, 2007 utilizing the current GLJ reserve report as at December 31, 2006.

Advisory

This press release contains forward-looking statements that involve known and unknown risks, uncertainties, assumptions and other factors, some of which are beyond Rock's control, that may cause actual results or events to differ materially from those anticipated in such forward-looking statements. Rock believes that the expectations reflected in those forward-looking statements are reasonable at the time made 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 press release should not be unduly relied upon. These statements speak only as of the date of such information, as the case may be, and may be superseded by subsequent events. Rock does not intend, and does not assume any obligation, to update these forward-looking statements, 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

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, 2006;

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 16, 2007

"signed"
Allen J. Bey
President and CEO

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, 2006;

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 16, 2007

"signed"

Peter D. Scott
Vice President, Finance and CFO

File No. 82-34785

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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 judgment, 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 15, 2007

Peter D. Scott
Vice President, Finance and Chief Financial Officer
March 15, 2007

Auditors' Report

We have audited the consolidated balance sheets of Rock Energy Inc. as at December 31, 2006 and 2005 and the consolidated statements of operations 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, 2006 and 2005 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 15, 2007

Consolidated Balance Sheets
(000s of dollars)

As at	December 31, 2006	December 31, 2005
Assets		
Current assets		
Cash and cash equivalents	$ -	$ 145
Accounts receivable	4,753	7,093
Prepaid expenses	532	385
	5,285	7,623
Property, plant and equipment *(note 4)*	97,229	95,271
Accumulated depletion and depreciation	(22,882)	(8,893)
	74,347	86,378
Goodwill	5,748	5,602
	$ 85,380	$ 99,603
Liabilities and Shareholders' Equity		
Current liabilities		
Accounts payable and accrued liabilities	$ 6,900	$ 9,090
Bank debt *(note 5)*	10,965	22,976
	17,865	32,066
Future tax liability *(note 9)*	4,942	5,204
Asset retirement obligation *(note 6)*	2,094	2,115
Shareholders' equity		
Share capital *(note 7)*	57,326	57,369
Contributed surplus *(note 8)*	1,641	453
Retained earnings	1,512	2,396
	60,479	60,218
Commitments *(note 11)*		
Subsequent event (note 12)		
	$ 85,380	$ 99,603

See accompanying notes to consolidated financial statements.

Approved by the Board:

Stuart G. Clark
Director

Allen J. Bey
Director

Consolidated Statements of Operations and Retained Earnings

(000s of dollars, except per share amounts)

Years ended	December 31, 2006	December 31, 2005
Revenues:		
Oil and natural gas revenue	$ 33,156	$ 22,873
Royalties, net of Alberta Royalty Tax Credit	(6,881)	(5,027)
Other income	198	317
	26,473	18,163
Expenses:		
General and administrative	2,278	1,411
Operating	9,255	4,745
Interest	924	457
Stock-based compensation *(note 8)*	1,188	485
Depletion, depreciation, and accretion	14,118	8,287
	27,763	15,385
Income (loss) before income taxes	(1,290)	2,778
Income taxes		
Current *(note 9)*	45	73
Future income taxes (reduction) *(note 9)*	(451)	1,196
Net income (loss) for the year	(884)	1,509
Retained earnings, beginning of year	2,396	887
Retained earnings, end of year	$ 1,512	$ 2,396
Diluted and basic net income (loss) per share *(note 7)*	$ (0.05)	$ 0.10

See accompanying notes to consolidated financial statements.

Consolidated Statements of Cash Flows

(000s of dollars)

Years ended	December 31, 2006	December 31, 2005
Cash provided by (used in):		
Operating:		
Net income (loss) for the year	$ (884)	$ 1,509
Add: Non-cash items:		
Depletion, depreciation, and accretion	14,118	8,287
Actual abandonment costs	(104)	(44)
Stock-based compensation	1,188	485
Future income taxes (reduction)	(451)	1,196
	13,867	11,433
Changes in non-cash working capital	2,571	(4,319)
	16,438	7,114
Financing:		
Issuance of common shares	-	217
Bank debt	(12,011)	22,976
Repurchase of stock options	-	(185)
	(12,011)	23,008
Investing:		
Property, plant and equipment	(32,879)	(23,644)
Acquisition of property, plant and equipment *(note 3)*	-	(23,880)
Disposition of property, plant and equipment	30,874	-
Changes in non-cash working capital	(2,567)	8,915
	(4,572)	(38,609)
Decrease in cash and cash equivalents	(145)	(8,487)
Cash and cash equivalents, beginning of year	145	8,632
Cash and cash equivalents, end of year	$ -	$ 145
Interest and taxes paid and received:		
Interest paid	960	428
Interest received	32	42
Taxes paid	$ 25	$ 57

See accompanying notes to consolidated financial statements.

Notes to Consolidated Financial Statements

Years ended December 31, 2006 and 2005

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 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. The Company follows the Canadian accounting standard relating to stock-based compensation and other stock-based payments as it applies to other stock-based compensation granted to employees, officers and directors. Under this standard, future 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 and the amounts used for ceiling test calculations are based on estimates of reserves, future costs and timing. 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. Acquisition of ELM/Optimum/Qwest

On March 14, 2005 the Company agreed to acquire, in two separate closings from 14 different entities (six private companies and eight drilling fund partnerships), petroleum and natural gas properties mainly through their various subsidiary companies. The transactions have been accounted for using the purchase method with the results of operations for each transaction included in the financial statements from the date of acquisition.

The first closing of the ELM/Optimum/Qwest properties occurred on April 7, 2005. The Company purchased all of the outstanding shares of 1143734 Alberta Ltd. and assets were purchased directly from three private entities and four drilling fund partnerships. The final purchase price equation is as follows:

($000)

Property, plant and equipment	$	16,483
Note payable*		(309)
Asset retirement obligation		(373)
	$	15,801
Consideration provided:		
Cash	$	4,575
Common shares (3,091,483)		10,944
Transaction costs		282
	$	15,801

** Paid to vendors on final adjustments*

The second closing of the ELM/Optimum/Qwest properties occurred on June 17, 2005. The Company purchased all of the outstanding shares of 1156168 Alberta Ltd., 1159203 Alberta Ltd. and 1140511 Alberta Ltd. The purchase price equation is as follows:

($000)

Property, plant and equipment	$	45,490
Note receivable*		148
Goodwill		4,593
Future income taxes		(4,593)
Asset retirement obligation		(1,007)
	$	44,631
Consideration provided:		
Cash	$	18,504
Common shares (7,234,005)		25,609
Transaction costs		518
	$	44,631

** Paid by vendors on final adjustments*

The purchase price allocations for both transactions were initially based on estimates of the fair values of the assets and liabilities as of the closing date, purchase price adjustments, transaction costs and holdback amounts.

4. Property, Plant and Equipment

($000)	December 31, 2006	December 31, 2005
Petroleum and natural gas properties	$ 96,887	$ 95,160
Other assets	342	111
	97,229	95,271
Accumulated depletion and depreciation	(22,882)	(8,893)
	$ 74,347	$ 86,378

In the third quarter of 2006, the Company disposed of four non-operated producing properties for total proceeds of approximately $30.9 million. The properties disposed of included Wild River, Highland/Hudson and Chestermere. As the change in the depletion rate was less than 20 percent. no gain has been booked into the financial statements.

At December 31. 2006, petroleum and natural gas properties included $8.220, (December 31. 2005 – $6,265 of unproved property costs which have been excluded from the depletable base.

During the year ended December 31. 2006, S1,627 (Year ended December 31. 2005 – $865) of administrative costs relating to exploration and development activities were capitalized as part of property, plant and equipment.

At December 31, 2006, 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$/bbl)	Cil Edmonton par (40 API) (Cdn$/bbl)	Natural gas AECE-C spot price (Cdn$/mmbtu)	Heavy Oil at Hardesty (12° API) (CDn$/bbl)	Currency exchange rate (US$/CDN$)
2007	62.00	70.25	7.20	39.25	0.87
2008	60.00	68.00	7.45	40.00	0.87
2009	58.00	65.75	7.75	39.75	0.87
2010	57.00	64.50	7.80	39.75	0.87
2011	57.00	64.50	7.85	40.25	0.87
2012	57.50	65.00	8.15	41.50	0.87
2013	58.50	66.25	8.30	42.50	0.87
2014	59.75	67.75	8.50	43.50	0.87
2015	61.00	69.C0	8.70	44.25	0.87
2016	62.25	70.50	8.90	45.25	0.87
2017	63.50	71.75	9.10	46.00	0.87
Thereafter (escalation)	2.0%/yr	2.0%/yr	2.0%/yr	2.0%/yr	0.87

5. Bank Debt

At December 31, 2006 the Company has 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 current limit under the facility is $18 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. The facility also bears a standby charge for un-drawn amounts. The facility was replaced in March 2007 (see note 12, Subsequent Event).

6. 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, 2006 is approximately $3,666 (December 31, 2005 – $3,385), which will be incurred between 2007 and 2019. 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.

A reconciliation of the asset retirement obligations is provided below:

	December 31, 2006	December 31, 2005
Balance, beginning of year	$ 2,115	$ 500
Liabilities incurred/acquired during year	413	1,583
Dispositions	(459)	-
Accretion	129	76
Actual retirement costs	(104)	(44)
Balance, end of year	$ 2,094	$ 2,115

7. 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, 2004	9,259,453	$ 21,276
Redemption *(i)*	(448)	(2)
Future tax effect of flow-through share renouncements *(ii)*		(723)
Issued for property acquisitions	10,325,488	36,552
Issued for flow-through shares *(iii)*	22,263	115
Issued for stock options exercised	30,565	151
Issued and outstanding as at December 31, 2005	19,637,321	$ 57,369
Future tax effect of flow-through share renouncements *(iii)*	-	(43)
Issued and outstanding as at December 31, 2006	19,637,321	$ 57,326

(i) In accordance with the terms of the 30-for-1 share consolidation shareholders holding 1,000 or fewer pre-consolidated common shares redeemed their shares for cash based on the value of $0.1129 per pre-consolidated share.

(ii) The Company has renounced resource expenditures on flow-through shares issued by predecessor companies. At March 31, 2004, the Company was committed to spending $1.8 million on drilling and exploration activities on or before January 31, 2005 to satisfy flow-through share commitments. At December 31, 2004, all required expenditures had been made and the Company completed the renouncements in February 2005.

(iii) 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.

As at December 31, 2006 and 2005 no preference shares were outstanding.

(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 expire 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, 2006 and December 31, 2005 and changes during the year ended on those dates:

	December 31, 2006		December 31, 2005	
	Options	Weighted-Average Exercise Price ($)	Options	Weighted-Average Exercise Price ($)
Outstanding, beginning of year	1,120,332	$4.51	532,387	$ 3.49
Granted	677,779	$3.66	777,944	$ 4.95
Exercised	-	-	(135,629)	$ 3.39
Forfeited	-	-	(54,370)	$ 3.58
Expired	(30,834)	$3.87	-	-
Outstanding, end of year	1,767,277	$4.19	1,120,332	$ 4.51

Options outstanding and exercisable under the stock option plan are summarized below as at December 31, 2006:

	Outstanding Options			Exercisable Options	
	Number of Options	Weighted-Average Exercise Price	Weighted-Average Years to Expiry	Number of Options	Weighted-Average Exercise Price ($)
$ 3.15 - $ 3.90	754,333	$ 3.30	1.83	155,777	$ 3.47
$ 4.00 - $ 5.11	1,012,944	$ 4.86	1.76	217,667	$ 4.93
	1,767,277	$ 4.19	1.79	373,444	$ 4.32

(D) PER SHARE AMOUNTS

The weighted average number of common shares outstanding during the year ended December 31, 2006 of 19,637,321 (year ended December 31, 2005 – 15,436,835) 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, 2006. As at December 31, 2006, an additional 17,660 (December 31, 2005 – 64,127) common shares were used to calculate diluted earnings per share.

8. 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, 2006 was estimated to be $976 (year ended December 31, 2005 – $1,658) as at the grant date using the Black-Scholes option pricing model and the following assumptions:

Risk-free interest rate	4.00% - 6.00%
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, 2006	December 31, 2005
Balance, beginning of year	$ 453	$ 202
Stock-based compensation expense	1,188	485
Net benefit on options exercised(1)	-	(234)
Balance, end of year	$ 1,641	$ 453

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

9. 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 33.70 percent (December 31, 2005 – 37.62 percent). The principal reasons for differences between such "expected" income tax expense and the amount actually recorded are as follows:

	December 31, 2006	December 31, 2005
Net income before income taxes	$ (1,290)	$ 2,778
Statutory income tax rate	33.7%	37.62%
Expected income taxes	$ (435)	$ 1,045
Add (deduct):		
Stock-based compensation	400	182
Non-deductible Crown charges	330	1,038
Change in enacted rates	(311)	-
Other	180	19
Resource allowance	(615)	(888)
Acquisition	-	12,133
Change in valuation allowance	-	(12,333)
Provision for income taxes	$ (451)	$ 1,196
Capital tax	45	73
Provision for (recovery of) income taxes	$ (406)	$ 1,269

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, 2006	December 31, 2005
Loss carry-forwards	$ 4,941	$ 9,097
Property, plant and equipment	(6,218)	(11,542)
Non-coterminous year-ends	(3,859)	(3,049)
Share issuance costs	263	360
Asset retirement obligation	649	719
Calculated future income tax liability	(4,224)	(4,415)
Valuation allowance	(718)	(789)
Future income taxes (liability)	$ (4,942)	$ (5,204)

At December 31, 2006, Rock and its subsidiary have tax pools aggregating $69.0 million prior to the allocation of deferred partnership income and $55.2 million (December 31, 2005 – $65.5 million) after the allocation of deferred partnership income. The non-capital losses prior to the allocation of deferred partnership income expire as follows:

2011	$ 479
2026	13,656
	$ 14,135

10. 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.

11. Commitments

Obligations with a fixed term are as follows:

	2007	2008	2009	2010	2011
Lease of office premises	$ 676	$ 895	$ 828	$ 828	$ 828

12. Subsequent Event

Subsequent to year-end the Company entered into a new demand operating facility with a different Canadian chartered bank. The new facility has a borrowing limit of $23 million, up from the current limit of $18 million. The new loan is based on the Company's 2005 reserve report by GLJ Petroleum Consultants Ltd. (GLJ) and internal estimates at September 30, 2006. The new facility will be reviewed before April 30, 2007 utilizing the current GLJ reserve report as at December 31, 2006.

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Management's Discussion & 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 discussion and analysis is dated March 15, 2007 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, 2006.

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 are a key measure that demonstrates the ability to generate cash to fund expenditures. Funds from operations are 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 are 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 7, 2006 for projected 2006 and 2007 results. The table below provides the guidance for 2006 with actual results.

2006 Guidance

	2006 Guidance	Actual	Change
2006 Production *(boe/d)*			
Annual	2,100	2,098	0%
Exit	2,200-2,400	2,200	(4)%
2006 Funds from Operations			
Annual	$13.5 million	$13.9 million	3%
Annual *(per share)*	$0.69	$0.71	3%
2006 Capital Budget			
Expenditures	$30 million	$33 million	10%
Gross wells drilled	31	33	6%
Total net debt at year end	$11 million	$12.6 million	15%
Pricing (Fourth Quarter)			
Oil – WTI	US$60.00/bbl	US$60.21/bbl	0%
Natural gas – AECO	$6.67/mcf	$6.69/mcf	0%
US/Cdn dollar exchange rate	0.90	0.88	(2)%

Production averages for the year and the exit rate were within the guidance range. Funds flow from operations was above guidance as higher pricing (lower than budgeted heavy oil differentials and higher realized natural gas prices) more than offset higher operating costs. Capital expenditures were higher than forecast as $2 million of the

2007 capital budget was accelerated into December 2006 in order to take advantage of rig availability and operational efficiencies to drill four (4.0 net) heavy oil wells. As a result debt levels at year-end were slightly above guidance.

Guidance for 2007 has been updated to reflect higher operating costs experienced by the Company and industry and acceleration of the 2007 capital budget into December 2006. The table below updates the Company's previous guidance that was issued November 7, 2006.

	2007 Previous Guidance	2007 Revised Guidance	Change
2007 Production *(boe/d)*			
Annual	2,200	2,200-2,400	5%
Exit	2,600-2,800	2,600-2,800	0%
2007 Funds from Operations			
Annual	$15 million	$15 million	0%
Annual – *(per share)*	$0.76	$0.76	0%
2007 Capital Budget			
Expenditures	$22 million	$20 million	(9)%
Gross wells drilled	20-25	16-21	(18)%
Total net debt at year-end	$18 million	$18 million	0%
Pricing (Annual)			
Oil – WTI	US$65.00/bbl	US$65.00/bbl	0%
Natural gas – AECO	Cdn$7.50/mcf	Cdn$7.50/mcf	0%
US/Cdn dollar exchange rate	0.90	0.90	0%

Operating costs have been trending up and, as a result, Rock has increased the per boe cost by $0.50/boe to approximately $11.25 per boe including transportation costs. The acceleration of capital into December 2006 has caused management to implement an annual average range for production as the wells drilled came on-stream in the first quarter instead of the third quarter. The annual cash flow associated with the increased production has been offset by the increase in operating costs. As a result, the year's cash flow and year-end debt levels have not been affected. While light oil pricing has initially been lower than forecast for 2007, heavy oil differentials have improved and, as a result, we have not altered our oil price. The Company has put in a new debt facility which increased the bank line from $18 million to $23 million. Capital expenditures in excess of funds from operations are projected to be $5 million and can be funded through this facility. The year-end debt to cash flow ratio is projected to be approximately 1.2:1. 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.

Production by Product

	12 Months Ended 12/31/06	12 Months Ended 12/31/05	Change	3 Months Ended 12/31/06	3 Months Ended 12/31/05	Change
Natural gas *(mcf/d)*	6,421	4,476	43%	3,528	8,147	(57)%
Oil *(bbls/d)*	179	133	35%	206	207	(1)%
Heavy Oil *(bbls/d)*	792	187	324%	1,168	480	143%
NGL *(bbls/d)*	57	56	2%	42	75	(44)%
Total (boe/d) *(6:1)*	2,098	1,122	87%	2,004	2,120	(5)%

Production by Area

	12 Months Ended 12/31/06	12 Months Ended 12/31/05	Change	3 Months Ended 12/31/06	3 Months Ended 12/31/05	Change
West Central Alberta *(boe/d)*	972	598	63%	652	1,189	(45)%
Plains *(boe/d)*	795	242	229%	1,171	510	130%
Other *(boe/d)*	331	282	17%	181	421	(57)%
Total (boe/d) *(6:1)*	2,098	1,122	87%	2,004	2,120	(5)%

Production increases for the year ended December 31, 2006 primarily came from two sources. First are the ELM/Optimum/Qwest acquisitions that were completed in stages and closed in April and June 2005, partially offset by the sale of approximately 820 boe per day of production in July 2006. Second, the Company's operated grassroots drilling program contributed the heavy oil additions in the Plains area and additional production from drilling on the acquired properties. Early in January 2007 Rock's production exceeded 2,200 boe per day.

Production decreased by 5 percent in the fourth quarter of 2006 from the same period last year as the property dispositions in the third quarter more than offset the additions from operational activities. Production additions in the quarter primarily came from the Plains core area, which added heavy oil production, and the workovers completed at Medicine River, which added light oil production. As a result of these activities the Company's product mix shifted more towards heavy oil.

Product Prices

	12 Months Ended 12/31/06	12 Months Ended 12/31/05	Change	3 Months Ended 12/31/06	3 Months Ended 12/31/05	Quarterly Change
Realized Product Prices						
Natural gas *($/mcf)*	7.07	10.22	(31)%	7.45	12.06	(38)%
Oil *($/bbl)*	64.46	64.95	(1)%	57.77	63.63	(9)%
Heavy oil *($/bbl)*	38.35	27.44	40%	34.86	24.81	41%
NGL *($/bbl)*	61.35	56.19	9%	65.47	58.80	11%
Combined average ($/boe) *(6:1)*	43.27	55.85	(23)%	40.73	60.29	(32)%

	12 Months Ended 12/31/06	12 Months Ended 12/31/05	Change	3 Months Ended 12/31/06	3 Months Ended 12/31/05	Quarterly Change
Average Reference Prices						
Natural gas – Henry Hub Daily Spot *(US$/mcf)*	6.75	8.89	(24)%	6.69	12.27	(45)%
Natural gas – AECO C Daily Spot *($/mcf)*	6.54	8.77	(25)%	6.99	11.43	(39)%
Oil – WTI Cushing, Oklahoma *(US$/bbl)*	66.22	56.56	17%	60.21	60.02	0%
Oil – Edmonton Light *($/bbl)*	72.77	68.72	6%	64.49	71.17	(9)%
Heavy Oil – Lloydminster blend *($/bbl)*	50.07	42.99	16%	43.84	41.81	5%
US/Cdn $ exchange rate	0.882	0.826	7%	0.878	0.852	3%

For the year and quarter ended December 31, 2006 the Company experienced higher heavy oil prices (approximately 40 percent increase) and lower natural gas prices (more than 30 percent reduction) than in the prior year's periods. Higher heavy oil prices resulted from higher WTI prices for the year and a significant decrease in the heavy oil to light oil differential. Structural changes in the marketplace such as pipeline reversals that have taken more heavy crude production out of Alberta to refineries in the mid-continent United States have contributed to the improvement in the heavy oil differential. The Company expects that these and other structural changes will continue to benefit the heavy oil market price. Natural gas prices have suffered from high storage levels as winter was delayed and the fourth quarter of 2006 was warmer than average. The combination of lower natural gas prices and the increase in heavy oil production in Rock's product mix over 2005 has caused the Company's weighted average per boe price to decrease by 23 percent for the year and 32 percent for the fourth quarter from the prior year's periods.

REVENUE

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

Oil and Natural Gas Revenue

	12 Months Ended 12/31/06	12 Months Ended 12/31/05	Change	3 Months Ended 12/31/06	3 Months Ended 12/31/05	Quarterly Change
Natural gas	$ 16,560	$ 16,695	(1)%	$ 2,408	$ 9,043	(73)%
Oil	4,195	3,152	33%	1,073	1,214	(12)%
Heavy Oil	11,124	1,871	495%	3,790	1,095	246%
NGL	1,277	1,155	11%	264	408	(35)%
	33,156	22,873	45%	7,535	11,760	(36)%
Other revenue	$ 198	$ 317	(38)%	$42	$ 100	(58)%

Oil and natural gas revenue increased by 45 percent for the year ended December 31, 2006 over 2005 due to higher production levels, particularly of heavy oil, which more than offsett the decline in product prices, particularly of natural gas. For the fourth quarter of 2006 oil and natural gas revenue decreased by 36 percent from the same period in 2005 as lower natural gas production and prices more than offset the increase in heavy oil production and prices. Other revenue decreased in 2006 from 2005 as the Company sold the property that was generating sulphur as part of the asset rationalization program in the third quarter of 2006.

Royalties

	12 Months Ended 12/31/06	12 Months Ended 12/31/05	Change	3 Months Ended 12/31/06	3 Months Ended 12/31/05	Quarterly Change
Royalties	$6,881	$5,027	37%	$1,452	$2,666	(46)%
As a percentage of oil and natural gas revenue	20.8%	22.0%	(5)%	19.3%	22.7%	(15)%
Per boe *(6:1)*	$8.98	$12.28	(27)%	$7.88	$13.67	(42)%

Royalties increased for the year ended December 31, 2006 over the prior year due to higher production levels partially offset by lower natural gas prices and the benefit of Alberta Royalty Tax Credit (ARTC). For the fourth quarter of 2006 royalties decreased from the fourth quarter of 2005 due to lower production, lower natural gas prices and the ARTC benefit. Royalties as a percentage of revenue and on a per-boe basis decreased in the 2006 periods from the 2005 periods primarily due to lower natural gas prices, ARTC benefit and the Company's production mix including a higher heavy oil component, which generally has a lower associated royalty rate. The Company is forecasting a royalty rate of 22 percent for 2007 as the ARTC program has been eliminated effective January 1, 2007.

Operating Expenses

	12 Months Ended 12/31/06	12 Months Ended 12/31/05	Change	3 Months Ended 12/31/06	3 Months Ended 12/31/05	Quarterly Change
Operating expense	$ 8,947	$ 4,470	100%	$ 2,429	$ 2,149	13%
Transportation costs	308	275	12%	83	158	(47)%
	9,255	4,745	95%	2,512	2,307	9%
Per boe *(6:1)*	$12.08	$11.59	4%	$13.63	$11.83	15%

Operating costs for the year ended December 31, 2006 have increased over 2005 primarily due to higher production. Operating expenses for both the year ended December 31, 2006 and the fourth quarter of 2006 include approximately $200 of natural gas processing costs related to 2005. Excluding these prior-period processing costs, operating costs for 2006 are $11.83 per boe, a 2 percent increase over 2005, and $12.56 per boe for the fourth quarter of 2006, a 6 percent increase over the prior period. Compared to the third quarter of 2006, fourth quarter per boe operating expenses have decreased by 4 percent once the 2005 processing costs are excluded. Operating costs per boe did not decrease as much as expected in the fourth quarter in part due to higher service costs associated with heavy oil operations and higher road and lease maintenance costs.

Heavy oil unit costs tend to be higher in the first several months of producing operations (the "clean-up period") due to high initial sand production, additional fuel costs incurred until the operation is capable of running on casing-head gas and injected load oil being used during the clean-up period, which reduces the sales volume from the operations. Heavy oil operating costs have decreased year-over-year by about 20 percent to about $13.00 per boe as the base level of production has increased and start-up operations have less of an impact on overall costs. The Company expects heavy oil costs per boe to continue to decrease in 2007. Transportation costs for the fourth quarter of 2006 decreased from the prior year's period as a result of the properties sold in the third quarter of 2006. Operating expenses per boe, including transportation expense, are forecast to be approximately $11.25 per boe in 2007.

General and Administrative (G&A) Expense

	12 Months Ended 12/31/06	12 Months Ended 12/31/05	Change	3 Months Ended 12/31/06	3 Months Ended 12/31/05	Quarterly Change
Gross	$ 3,905	$ 2,275	69%	$ 1,085	$ 814	27%
Per boe *(6:1)*	5.10	5.55	(9)%	5.89	4.17	34%
Capitalized	1,627	864	83%	395	288	19%
Per boe *(6:1)*	2.12	2.11	(2)%	2.14	1.47	26%
Net	2,278	1,411	61%	690	526	31%
Per boe *(6:1)*	$2.97	$3.44	(14)%	$3.74	$2.70	39%

G&A expense increased on an absolute basis in 2006 over 2005 as the Company's operations continued to grow and new staff was added. G&A expense on a per-boe basis for the year ended December 31, 2006 dropped from the prior year's period as production increased. For the fourth quarter of 2006, G&A expense per boe increased over 2005 as production decreased as a result of the property dispositions in the third quarter of 2006, because costs for year-end activities increased and because approximately $56 ($0.30 per boe) of bad debt related to the ELM/Optimum/Qwest acquisition was written off. Rock capitalizes certain G&A expenses based on personnel involved in the exploration and development initiatives, including salaries and related overhead costs. G&A expenses are expected to rise in 2007 on an absolute basis as industry costs increase.

Interest Expense

	12 Months Ended 12/31/06	12 Months Ended 12/31/05	Change	3 Months Ended 12/31/06	3 Months Ended 12/31/05	Quarterly Change
Interest expense (recovery)	$ 924	$ 457	100%	$ 141	$ 261	(46)%
Per boe *(6:1)*	$1.21	$1.12	8%	$0.76	$1.34	(43)%

Interest expense for 2006 doubled over 2005 as a result of higher average bank debt for the year. For the fourth quarter of 2006 interest expense was about half of interest expense for the same period of 2005 as bank debt was reduced in the third quarter of 2006 with proceeds from the asset rationalization program. Interest expense is expected to increase in 2007 due to higher average bank debt but to be approximately the same on a per boe basis as in 2006.

Depletion, Depreciation, and Accretion (DD&A)

	12 Months Ended 12/31/06	12 Months Ended 12/31/05	Change	3 Months Ended 12/31/06	3 Months Ended 12/31/05	Quarterly Change
D&D expense	$ 13,989	$ 8,211	70%	$ 2,707	$ 3,994	(32)%
Per boe *(6:1)*	$18.27	$20.05	(9)%	$14.69	$20.48	(28)%
Accretion expense	$ 129	$ 76	70%	$ 34	$ 31	10%
Per boe *(6:1)*	$0.17	$0.19	(11)%	$0.18	$0.16	13%

Depletion and depreciation expense for year ended December 31, 2006 increased over the prior year due to higher production but decreased for the fourth quarter of 2006 from the 2005 period primarily as Company reserves increased faster than the cost base. Reserve additions in 2006 also caused the depletion and depreciation expense per boe to decrease in 2006 from 2005.

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 or constructing facilities. Similarly, this obligation can also be reduced as a result of abandonment work undertaken and reducing future obligations. During the year ended December 31, 2006 capital programs increased the underlying ARO by $413 (December 31, 2005 – $1,583) and actual expenditures on abandonments were $104 (December 31, 2005 – $44).

INCOME TAX

The Company began to pay capital taxes in 2005 as its capital base increased significantly following the acquisitions in 2005. Federal large corporations tax was eliminated beginning in 2006; however, 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 2007 as the Company and its subsidiaries have estimated resource and other pools available at December 31, 2006 (after the allocation of deferred partnership income) of approximately $55.2 million as set out below:

CEE	$	14.9 million
CDE	$	25.9 million
UCC	$	12.8 million
Loss carry-forwards	$	0.3 million
Other	$	1.3 million
Total	$	55.2 million

Funds from Operations and Net Income

	12 Months Ended 12/31/06	12 Months Ended 12/31/05	Change	3 Months Ended 12/31/06	3 Months Ended 12/31/05	Quarterly Change
Funds from operations	$13,867	$11,433	21%	$2,644	$6,020	(56)%
Per boe *(6:1)*	$18.11	$27.92	(35)%	$14.35	$30.86	(54)%
Per share:						
Basic	$0.71	$ 0.74	(4)%	$0.13	$ 0.31	(58)%
Diluted	$0.71	$ 0.74	(4)%	$0.13	$ 0.31	(58)%
Net income (loss)	($884)	$ 1,510	(159)%	($119)	$ 747	(116)%
Per boe *(6:1)*	($1.15)	$3.69	(131)%	($0.65)	$3.83	(117)%
Per share:						
Basic	($0.05)	$ 0.10	(150)%	($0.01)	$ 0.04	(125)%
Diluted	($0.05)	$ 0.10	(150)%	($0.01)	$ 0.04	(125)%
Weighted average shares outstanding:						
Basic	19,637	15,437	27%	19,637	19,596	0%
Diluted	19,655	15,501	27%	19,637	19,682	0%

The Company did not issue any shares in 2006. In 2005 the majority of shares issued were for the acquisitions completed in the second quarter of 2005, when 10.3 million shares were issued.

Funds from operations for the year ended December 31, 2006 increased by 21 percent over 2005 as the increase in production more than offset the decrease in realized prices, primarily for natural gas, and the increase in royalties, operating, G&A and interest costs. On a per-boe basis 2006 funds from operations decreased by 35 percent from 2005 primarily as the reduction in realized prices more than offset the reduction in royalties. For the fourth quarter of 2006 funds from operations decreased by approximately 56 percent on an absolute and 54 percent on a per boe-basis from to the prior year's periods as the reduction in prices (primarily for natural gas) and increase in operating and G&A costs more than offset the reduction in royalties. The Company generated a net loss for the year and quarter ended December 31, 2006 as the level of depletion and increase in stock-based compensation exceeded funds from operations.

Capital Expenditures

($000)	12 Months Ended 12/31/06	12 Months Ended 12/31/05	Change	3 Months Ended 12/31/06	3 Months Ended 12/31/05	Quarterly Change
Land	$ 4,822	$ 3,737	29%	$ 120	$ 1,664	(93)%
Seismic	1,081	1,761	(39)%	127	878	(86)%
Drilling and completions	25,130	16,301	50%	5,758	5,783	0%
Capitalized G&A	1,627	865	88%	395	288	37%
Gas gathering systems	247	7	3,429%	–	35	(99)%
Total operations	$ 32,907	$ 23,171	42%	$ 6,400	$ 8,648	(26)%
Property acquisitions (dispositions)	(30,874)	60,593	(151)%	Nil	Nil	n/a
Well site facilities inventory	(165)	401	(141)%	(206)	(895)	(77)%
Office equipment	136	72	89%	39	15	160%
Total (net of acquisitions and dispositions)	$ 2,004	$ 84,237	(98)%	$ 6,233	$ 7,768	(20)%

Capital expenditures for operations increased for the year ended December 31, 2006 over 2005 as Rock drilled the same number of gross wells (33) but more net wells (28.3 in 2006 versus 22.4 in 2005) as the Company gained more control over its operations. The Company participated in more West Central core area operations, including re-completions and, as a result, drilling and completions costs increased by 50 percent. In total Rock participated in nine (6.1 net) re-completions, which included one (0.8 net) natural gas well in the Musreau area which is expected to be tied-in in the fourth quarter of 2007, when third-party facilities are expanded, and one (1.0 net) oil well at Medicine River, which was brought on-production in the fourth quarter of 2006.

Land expenditures increased as the Company continued to build its West Central core area presence. Seismic expenditures decreased as the number of programs shot in the Plains core area decreased with Rock's shift to the West Central core area. Total net capital expenditures were reduced to $2 million in 2006 from $84 million in 2005 as the proceeds from the Company's asset rationalization program essentially offset capital expenditures from operations. In 2005 the Company completed the ELM/Optimum/Qwest acquisitions which significantly increased total capital expenditures.

During 2006, Rock drilled 27 (27.0 net) operated wells and six (1.3 net) non-operated wells, achieving a 96 percent success rate, compared to 20 (20.0 net) operated wells and 13 (2.1 net) non-operated wells and an 82 percent success rate in 2005. In the Plains core area Rock drilled 25 (25.0 net) heavy oil wells and one (1.0 net) dry hole. All of the wells were operated and all successful wells were on-production at year end except four (4.0 net) wells drilled in December 2006, which were brought on-production in the first quarter of 2007. Rock had no production from the Plains area at the beginning of 2005 and exited with approximately 670 boe per day in 2005 and 1,250 boe per day in 2006. In the West Central Alberta core area in 2006 Rock drilled two (0.9 net) oil wells in the Niton area, three (1.2 net) natural gas wells and one (0.1 net) dry hole. Of the three gas wells two (1.1 net) were drilled in the Musreau area and are expected to be tied-in in the fourth quarter of 2007 along with the re-completed well. In aggregate the Musreau-area wells are projected to initially increase Rock's production by 300 boe per day once tied-in. For the fourth quarter of 2006 capital expenditures decreased by approximately $2 million from 2005 levels as land and seismic activity decreased in the quarter.

LIQUIDITY AND CAPITAL RESOURCES

Rock's current approved capital budget for 2007 projects spending of $20 million. In 2007 funds from operations are expected to be approximately $15 million. The capital spending in excess of cash flow is intended to be funded through bank debt. Subsequent to year-end the Company arranged a new $23 million bank facility with a different chartered bank to replace its existing bank facility. With year-end debt of $12.6 million Rock has room to fund the $5 million of capital expenditures in excess of expected cash flow for 2007. The new bank facility will be reviewed by April 30, 2007 with the Company's 2006 independent reserve report. Based on the drilling in the fourth quarter of 2006, Rock expects, subject to any changes to the bank's commodity price forecast, an increase to the borrowing base. The Company will continue to monitor capital expenditures, cash flow from operations and debt levels and make adjustments, in order to ensure the projected debt to cash flow ratio does not exceed 1.5:1.

The Company has a demand operating loan facility with a Canadian chartered bank. This facility was put in place subsequent to year-end with a new lender and the Company's previous facility was repaid. The new facility is subject to the bank's valuation of the Company's oil and natural gas assets and the credit currently available is $23 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 un-drawn 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 facility is currently under its annual review. As at March 15, 2007 approximately $14.7 million was drawn under the facility.

SELECTED ANNUAL DATA

The following table provides selected annual information for Rock. The Company changed its year-end at December 31, 2004 from March 31, 2004. In order to make comparisons of periods compatible, information presented for the 12-month period ended December 31, 2004 has been compiled by combining the nine-month period ended December 31, 2004 with the three-month period ended March 31, 2004.

	12 Months Ended 12/31/06	12 Months Ended 12/31/05	12 Months Ended 12/31/04
Production *(boe/d)*	2,098	1,122	181
Oil and natural gas revenues ($000)	$ 33,156	$ 22,873	$ 2,845
Average realized price *($/boe)*	$43.27	$ 55.85	$ 43.02
Royalties *($/boe)*	$8.98	$ 12.28	$ 9.89
Operating expense *($/boe)*	$12.08	$ 11.59	$ 7.97
Operating netback *($/boe)*	$22.21	$ 31.98	$ 25.16
Net G&A expense ($000)	$2,278	$ 1,411	$ 959
Stock-based compensation ($000)	$ 1,188	$ 485	$ 202
Funds from operations ($000)	$ 13,867	$ 11,433	$ 1,218
Per share – basic	$0.71	$ 0.74	$ 0.14
Per share – diluted	$0.71	$ 0.74	$ 0.14
Net income (loss)	($884)	$ 1,510	$ 571
Per share – basic	($0.05)	$ 0.10	$ 0.06
Per share – diluted	($0.05)	$ 0.10	$ 0.06
	As at 12/31/06	As at 12/31/05	As at 12/31/04
Total assets	$ 85,306	$ 99,604	$ 25,057
Total liabilities	$ 24,827	$ 39,385	$ 2,693

SELECTED QUARTERLY DATA

The following table provides selected quarterly information for Rock:

	3 Months Ended 12/31/06	3 Months Ended 09/30/06	3 Months Ended 06/30/06	3 Months Ended 03/31/06	3 Months Ended 12/31/05	3 Months Ended 09/30/05	3 Months Ended 06/30/05	3 Months Ended 03/31/05
Production *(boe/d)*	2,004	1,613	2,190	2,594	2,120	1,343	693	309
Oil and natural gas revenues ($000)	$ 7,535	$ 7,023	$ 8,774	$ 9,824	$ 11,760	$ 7,030	$ 2,924	$ 1,159
Average realized price *($/boe)*	$40.73	$47.30	$44.01	$42.08	$60.29	$56.90	$46.36	$41.65
Royalties *($/boe)*	$7.88	$5.27	$8.97	$12.26	$13.67	$11.61	$10.39	$9.73
Operating expense *($/boe)*	$13.63	$13.13	$10.55	$11.55	$11.83	$13.19	$8.62	$9.49
Operating netback *($/boe)*	$19.22	$28.90	$24.49	$18.27	$34.79	$32.10	$27.35	$22.43
Net G&A expense *($000)*	$ 690	$ 477	$ 462	$ 649	$ 526	$ 329	$ 282	$ 274
Stock-based compensation *($000)*	$ 295	$ 308	$ 305	$ 280	$ 257	$ 131	$ 55	$ 42
Funds from operations *($000)*	$ 2,644	$ 3,791	$ 4,028	$ 3,404	$ 6,020	$ 3,552	$ 1,469	$ 392
Per share – basic	$0.13	$ 0.19	$ 0.21	$ 0.17	$ 0.31	$ 0.18	$ 0.11	$ 0.04
Per share – diluted	$0.13	$ 0.19	$ 0.21	$ 0.17	$ 0.31	$ 0.18	$ 0.11	$ 0.04
Net income (loss) *($000)*	($119)	$ 891	($ 583)	($ 1,074)	$ 747	$ 634	$ 77	$ 51
Per share – basic	($0.01)	$ 0.05	($ 0.03)	($ 0.05)	$ 0.04	$ 0.03	$ 0.01	$ 0.01
Per share – diluted	($0.01)	$ 0.05	($ 0.03)	($ 0.05)	$ 0.04	$ 0.03	$ 0.01	$ 0.01
Capital expenditures *($000)*	$ 6,223	$ 12,520	$ 4,397	$ 9,728	$ 7,768	$ 7,920	$ 66,411	$ 2,138

	As at 12/31/06	As at 09/30/06	As at 06/30/06	As at 03/31/06	As at 12/31/05	As at 09/30/05	As at 06/30/05	As at 03/31/05
Working capital *($000)*	($12,580)	($8,990)	($31,135)	($30,766)	($24,442)	($22,643)	($18,093)	$10,297

Production has grown over the last two quarters of 2006 subsequent to the asset rationalization program which was completed in the third quarter of 2006. Immediately following these dispositions Rock's production was approximately 1,400 boe per day. Production growth has primarily come from drilling operations in the Plains core area and well recompletions at the Medicine River property near Sylvan Lake. Over the same period corporate average product prices have decreased as natural gas and oil prices declined. Heavy oil prices decreased in the fourth quarter, as expected, due to seasonality but in general were higher than 2005 levels. Royalty rates have generally improved in 2006 as Rock's product mix became more heavily weighted to oil, which usually has a lower royalty rate than gas, and because of Rock receiving the ARTC benefit.

Operating costs per boe have fluctuated depending on the amount of heavy oil start-up operations in any particular period, and the fourth quarter of 2006 included $200,000 relating to 2005 gas processing cost adjustments. Without these costs fourth quarter operating costs per boe would have decreased to $12.57 per boe. Field netbacks generally declined in 2006 from 2005 due to lower product prices. G&A expenses continued to rise as staffing levels increased throughout the period as the Company's activity levels grew. Funds from operations and net income or loss have been primarily affected by the change in product prices as changes in operating costs and royalty rates tended to offset each other. Net capital expenditures were significantly impacted by the asset rationalization program in the third quarter of 2006, which generated proceeds of $30.9 million, and by the acquisitions in the second quarter of 2005, which incurred costs of $60.5 million. The second quarter of the year tends to be a slower operational period with respect to capital investments due to the effects of spring break-up.

Reserves

Rock's reserves have been independently evaluated by GLJ Petroleum Consultants Ltd. (GLJ) at year-end 2006. This is the third year in which GLJ has evaluated the Company's reserves. The reserves as at December 31, 2006 and 2005 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 2005 and year-end 2006. NI 51-101 requires reserves to be reconciled on a net basis (after deducting royalties but including any royalty interests) ("net interest"). In addition, in the tables below Rock has also provided a reserve reconciliation on a gross basis (before deducting royalties and without including any royalty interest) ("gross interest").

Rock's gross interest reserves at year-end 2006 are 4.4 million boe of proved reserves and 7.3 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 2.0 million boe of proved reserves and 3.6 million boe of proved plus probable reserves.

RESERVES RECONCILIATION

The following table is a reconciliation of Rock's gross interest reserves at December 31, 2006 using GLJ's forecast pricing and cost estimates as at December 31, 2006.

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

	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, 2005	331	427	111	146	1,128	2,096	14,427	19,657	3,974	5,946
Additions[1]	121	197	22	53	1,734	2,500	1,825	5,240	2,181	3,624
Technical revisions[2]	36	41	8	6	132	(8)	(218)	(613)	140	(65)
Acquisitions	0	0	0	0	0	0	0	0	0	0
Dispositions	(10)	(12)	(1)	(1)	0	0	(6,186)	(8,358)	(1,042)	(1,406)
Production	(65)	(65)	(21)	(21)	(289)	(289)	(2,342)	(2,342)	(765)	(765)
December 31, 2006	413	588	118	183	2,705	4,299	7,506	13,584	4,488	7,334

(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.

The following table is a reconciliation of Rock's net interest reserves at December 31, 2006 using GLJ's forecast pricing and cost estimates as at December 31, 2006.

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

	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, 2005	286	371	78	102	926	1,712	10,648	14,608	3,065	4,621
Additions[1]	88	144	17	39	1,397	2,010	1,531	4,192	1,757	2,891
Technical revisions[2]	17	22	7	4	144	27	(234)	(570)	128	(43)
Acquisitions	0	0	0	0	0	0	0	0	0	0
Dispositions	(8)	(8)	0	0	0	0	(4,406)	(5,924)	(742)	(995)
Production	(30)	(30)	(18)	(18)	(260)	(260)	(1,588)	(1,588)	(572)	(572)
December 31, 2006	353	499	84	128	2,207	3,489	5,951	10,719	3,636	5,902

(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.

RESERVES AND NET PRESENT VALUE (FORECAST PRICES AND COSTS)

The following tables summarize Rock's remaining oil and natural gas reserve volumes along with the value of future net revenue utilizing GLJ's forecast pricing and cost estimates as at December 31, 2006.

Reserves

	Oil		NGL		Heavy Oil		Natural Gas	
Reserves Category	Gross (mbbl)	Net (mbbl)	Gross (mbbl)	Net (mbbl)	Gross (mbbl)	Net (mbbl)	Gross (mmcf)	Net (mmcf)
Proved								
Proved Producing	371	315	101	72	2,180	1,788	4,909	3,790
Proved Non-Producing	42	38	18	12	106	84	2,250	1,910
Proved Undeveloped	0	0	0	0	419	335	348	251
Total Proved	413	353	119	84	2,705	2,207	7,507	5,951
Probable Additional	175	145	63	44	1,594	1,282	6,084	4,768
Total Proved Plus Probable	588	499	183	128	4,299	3,489	13,591	10,719

Note: Figures may not add due to rounding.

Net Present Value of Future Net Revenue

	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	78,425	67,396	59,563	53,638	48,959	70,150	60,789	54,048	48,909	44,829
Proved Non-Producing	12,887	10,303	8,588	7,345	6.395	8.729	6,839	5,601	4,715	4,044
Proved Undeveloped	5,665	4,925	4,307	3,786	3.343	3.717	3,112	2,626	2,229	1,899
Total Proved	96,977	82,624	72,457	64,769	58,697	82,596	70,740	62,276	55,853	50,773
Probable Additional	60,052	43,397	33,231	26,839	21,486	40,801	29,124	21,982	17,718	13,744
Total Proved Plus Probable	157,029	126,021	105,688	91,158	80,183	123,397	99,864	84,257	73,031	64,517

Note: Figures may not add due to rounding.

RESERVES AND NET PRESENT VALUE (CONSTANT PRICES AND COSTS)

The following tables summarize Rock's remaining oil and natural gas reserves along with the value of future net revenue utilizing GLJ's constant pricing and costs estimates. Pricing was based on benchmark reference prices posted at or near December 31, 2006 with adjustments for oil differential and natural gas heating values applied to arrive at a company average. Capital and operating costs were not inflated.

Reserves

	Oil		NGL		Heavy Oil		Natural Gas	
Reserves Category	Gross (mbbl)	Net (mbbl)	Gross (mbbl)	Net (mbbl)	Gross (mbbl)	Net (mbbl)	Gross (mmcf)	Net (mmcf)
Proved								
Proved Producing	375	319	101	71	2,180	1,790	4,928	3,804
Proved Non-Producing	42	38	18	12	106	84	2,238	1,939
Proved Undeveloped	0	0	0	0	419	335	348	254
Total Proved	417	357	119	84	2,705	2,209	7,514	5,996
Probable Additional	175	146	63	44	1,594	1,284	6,026	4,713
Total Proved Plus Probable	592	503	182	128	4,299	3,493	13,540	10,709

Note: Figures may not add due to rounding.

Net Present Value of Future Net Revenue

	Before Income Taxes					After Income Taxes				
	Discounted at (% per year)					Discounted at (% per year)				
Reserves Category	0	5	10	15	20	0	5	10	15	20
Proved										
Proved Producing	72,077	62,251	55,181	49,783	45,492	65,890	57,307	51,063	46,266	42,436
Proved Non-Producing	9,858	8,027	6,739	5,775	5,024	6,657	5,297	4,353	3,657	3,122
Proved Undeveloped	5,131	4,447	3,875	3,393	2,983	3,365	2,796	2,340	1,968	1,659
Total Proved	87,067	74,726	65,795	58,951	53,500	75,912	65,400	57,757	51,891	47,218
Probable Additional	48,533	35,925	27,897	22,330	18,256	32,952	24,026	18,341	14,407	11,536
Total Proved Plus Probable	135,600	110,651	93,693	81,281	71,756	108,864	89,425	76,098	66,298	58,753

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 Constant Prices and Costs evaluation and the Forecast Prices and Costs evaluation.

Summary of Pricing and Cost Rate Assumptions at December 31, 2006 – Constant Prices and Costs

	Edmonton Par Oil Price 40 API (Cdn$/bbl)	AECO Gas Price (Cdn$/mcf	Edmonton Pentane (Cdn$/bbl)	Edmonton Propane (Cdn$/bbl)	Edmonton Butane (Cdn$/bbl)	Spec Ethane (Cdn$/bbl)	EXCHANGE RATE (US$/Cdn$)
	67.58	6.07	71.55	43.25	54.06	20.43	0.8581

Summary of Pricing and Cost Rate Assumptions at December 31, 2006 – Forecast Prices and Costs

	Oil				NGL			Natural Gas			
Year	WTI Cushing (US$/bbl)	Edmonton Reference Price ($/bbl)	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)
2007	62.00	70.25	61.25	39.25	45.00	56.25	71.75	24.25	7.20	0.87	2
2008	60.00	68.00	59.25	40.00	43.50	50.25	69.25	25.25	7.45	0.87	2
2009	58.00	65.75	57.25	39.75	42.00	48.75	67.00	26.25	7.75	0.87	2
2010	57.00	64.50	56.00	39.75	41.25	47.75	65.75	26.50	7.80	0.87	2
2011	57.00	64.50	56.00	40.25	41.25	47.75	65.75	26.50	7.85	0.87	2
2012	57.50	65.00	56.50	41.50	41.50	48.00	66.25	27.75	8.15	0.87	2
2013	58.50	66.25	57.75	42.50	42.50	49.00	67.50	28.25	8.30	0.87	2
2014	59.75	67.75	59.00	43.50	43.25	50.25	69.00	29.00	8.50	0.87	2
2015	61.00	69.00	60.00	44.25	44.25	51.00	70.50	29.50	8.70	0.87	2
2016	62.25	70.50	61.25	45.25	45.00	52.25	72.00	30.00	8.90	0.87	2
2017	63.50	71.75	62.50	46.00	46.00	53.00	73.25	30.75	9.10	0.87	2
2018+	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	0.87	2

FINDING, DEVELOPMENT AND ACQUISITION COSTS

The following table summarizes Rock's finding, development and acquisition costs for the years ended December 31, 2006 and 2005 and the nine months ended 2004, including future development costs. Due to the change in the Company's year-end in 2004 only nine-month data is shown for finding and development costs for 2004, given the availability of independent reserve information for that period.

	12 months ended Dec. 31, 2006	12 months ended Dec. 31, 2005	9 months ended Dec. 31, 2004	Period Cumulative Total
Oil and Natural Gas Operations:				
Proved finding and development costs				
Capital expenditures[1] *($000)*	$32,907	$22,912	$5,876	$61,695
Future capital costs *($000)*	2,939	962	1,174	5,075
Total capital *($000)*	$35,846	$23.874	$7,050	$66,877
Reserve additions[2] *(mboe)*	2.181	1,188	294	6,663
Proved finding and development costs *($/boe)*	$16.44	$20.10	$23.98	$18.23
Proved Plus Probable finding and development costs				
Capital expenditures[1] *($000)*	$32,907	$22,912	$5,876	$61,695
Future capital costs *($000)*	7,986	3,900	$3,051	$14,937
Total capital *($000)*	$40,893	$26,812	$8,927	$76,739
Reserve additions[2] *(mboe)*	3,624	2,201	551	6,376
Proved Plus Probable finding and development costs *($/boe)*	$11.28	$12.18	$16.20	$12.02
Acquisitions/Dispositions:				
Proved finding and development costs – Acquisitions (Dispositions)				
Capital expenditures[1] *($000)*	($30,878)	$60,853	-	$29,975
Future capital costs *($000)*	(2,400)	3,647	-	1,247
Total capital *($000)*	($33,278)	$64,500	-	$31,222
Reserve additions *(mboe)*	(1.042)	2,397	-	1,355
Proved finding and development costs *($/boe)*	($31.94)	$26.91	-	$23.04
Proved Plus Probable finding and development costs – Acquisitions (Dispositions)				
Capital expenditures[1] *($000)*	($30,878)	$60,853	-	$29,975
Future capital costs *($000)*	(2,400)	3,733	-	1,333
Total capital *($000)*	($33,278)	$64,586	-	$31,308
Reserve additions *(mboe)*	(1,406)	3.154		
Proved + Probable finding and development costs *($/boe)*	($23.67)	$20.48	-	$17.91
Total Activities:				
Proved finding and development costs				
Capital expenditures[1] *($000)*	$2,029	$83.765	$5,876	$91,670
Future capital costs *($000)*	539	4.609	1,174	6,322
Total capital *($000)*	$2,568	$88.374	$7,050	$98,099
Reserve additions[3] *(mboe)*	1,279	3,620	273	5,172
Total Proved finding and development costs *($/boe)*	$2.01	$24.41	$25.82	$18.95
Proved Plus Probable finding and development costs				
Capital expenditures[1] *($000)*	$2,029	$83.765	$5,876	$91,670
Future capital costs *($000)*	5,586	7,633	3,051	16,270
Total capital *($000)*	$7,615	$91.398	$8,927	$108,047
Reserve additions[3] *(mboe)*	2,153	5.284	422	7,859
Total Proved Plus Probable finding and development costs *($/boe)*	$3.54	$17.30	$21.15	$13.73

[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 and development 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. Finding and development costs on operations improved in 2006 compared to 2005 and 2004 primarily as Rock's grassroots exploration and development program gained momentum. Capital costs on operations for 2005 and 2004 included a relatively high land and seismic component, 23 percent and 48 percent of expenditures respectively, which increased finding and development costs.

Rock's 2007 capital budget has approximately 25 percent of the spending allocated to land and seismic as the Company continues to build its grassroots program, particularly in the West Central Alberta core area. Finding and development costs on the acquired properties are based on the reserve evaluation as at December 31, 2005 and were increased by the amount of production from the closing date to December 31, 2005 to provide an estimate of the reserves purchased. Finding and development 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. Finding and development costs for total activities include operations, acquisitions, dispositions and reserve revisions.

LAND HOLDINGS

The following table summarizes Rock's land holdings as at December 31, 2006 and 2005:

(acres)		Dec. 31, 2006	Dec. 31, 2005	Change
Developed	– Gross	63,085	79,188	(20)%
	– Net	23,566	31,378	(25)%
Undeveloped	– Gross	76,030	79,666	(5)%
	– Net	39,429	36,898	7%
Total	– Gross	139,115	158,854	(12)%
	– Net	62,995	68,276	(8)%

NET ASSET VALUE

The following table summarizes Rock's net asset value and net asset value per share as at December 31, 2006 and December 31, 2005:

($000 except number of shares and net asset value per share)	December 31, 2006	December 31, 2005	Change
Proved plus probable reserves(1)	105,688	87,315	21%
Undeveloped land(2)	8,220	8,448	(3)%
Seismic(3)	3,550	2,617	36%
Working capital including debt	(12,580)	(24,442)	49%
Option proceeds	7,405	5,053	47%
Net Asset Value (Diluted)	112,283	78,991	42%
Diluted shares *(000)*	21,405	20,758	3%
Net asset value per share	$5.25	$3.81	38%

(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 2006 and 2005 forecast pricing and costs estimates and using a discount rate of 10 percent.

(2) 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.

(3) Seismic value is based on actual cost of seismic acquired or purchased.

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:

	2007	2008	2009	2010	2011
Office premise leases	$ 676	$ 895	$ 828	$ 828	$ 828
Demand bank loan[1]	$10,965				

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

OUTSTANDING SHARE DATA

At December 31, 2006 and to date, Rock had 19,637,321 common shares outstanding. At December 31, 2006 the Company had 1,767,277 stock options outstanding with an average exercise price of $4.19 per share.

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 Chief Executive Officer and the Chief Financial Officer have evaluated the effectiveness of the disclosure controls and procedures as at December 31, 2006 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, 2006. 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

There has been no change in accounting policies since the Company's last fiscal year-end.

NEW ACCOUNTING PRONOUNCEMENTS

Comprehensive Income

The Canadian Institute of Chartered Accountants (CICA) issued CICA Handbook section 1530, Comprehensive Income. The section is effective for fiscal years beginning on or after October 1, 2006. It describes how to report and disclose comprehensive income and its components. An integral part of the accounting standards on recognition and measurement of financial instruments is the ability to present certain gains and losses outside net income, in other comprehensive income. This standard requires that a company present comprehensive income and its components in a financial statement displayed with the same prominence as other financial statements that constitute a complete set of financial statements, in both annual and interim financial statements.

The CICA also made changes to CICA Handbook section 3250, Surplus, and reissued it as section 3251, Equity. The section is also effective for fiscal years beginning on or after October 1, 2006. The changes in how to report and disclose equity and changes in equity are consistent with the new requirements of section 1530, Comprehensive Income.

Rock will adopt this section effective January 1, 2007 but the Company does not expect this section to have a material impact on its consolidated financial statements.

Financial Instruments – Recognition and Measurement

The CICA issued CICA Handbook section 3855, Financial Instruments – Recognition and Measurement. The section is effective for fiscal years beginning on or after October 1, 2006. It describes the standards for recognizing and measuring financial assets, financial liabilities and non-financial derivatives. This section requires that all financial assets be measured at fair value, with some exceptions; all financial liabilities be measured at fair value if they are derivatives or classified as held for trading purposes (other financial liabilities are measured at their carrying value); and all derivative financial instruments be measured at fair value, even when they are part of a hedging relationship.

Rock will adopt this section effective January 1, 2007 but does not expect this section to have a material impact on its consolidated financial statements.

Hedges

The CICA issued CICA Handbook section 3865, Hedges. The section is effective for fiscal years beginning on or after October 1, 2006, and describes when and how hedge accounting can be used. Hedging is an activity used by a company to change an exposure to one or more risks by creating an offset between changes in the fair value of a hedged item and a hedging item; changes in the cash flows attributable to a hedged item and a hedging item; or changes resulting from a risk exposure relating to a hedged item and a hedging item. Hedge accounting ensures that all gains, losses, revenues and expenses from the derivative and the item it hedges are recorded in the income statement in the same period.

Rock will adopt this section effective January 1, 2007 but does not expect this section to have a material impact on its consolidated financial statements.

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 judgments 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 judgment 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. Judgments 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 were 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 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 high activity levels the industry has been experiencing, 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.

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 1800, 700 - 9th Avenue S.W., Calgary, Alberta, T2P 3V4.

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