

Anderson Energy Announces 2010 Fourth Quarter and Year End Results

Calgary, Alberta, March 28, 2011 - Anderson Energy Ltd. (“Anderson Energy” or the “Company”) (TSX:AXL) is pleased to announce its operating and financial results for the fourth quarter and year ended December 31, 2010.

Repositioning for oil production growth continues to be the primary focus of the Company in light of the current and projected weakness in natural gas pricing. As detailed in the following discussion, production from the Cardium horizontal oil drilling program initiated in the summer of 2010 started to come on-stream in the fourth quarter of 2010. The Company is making progress in its efforts to acquire additional Cardium acreage and implement drilling and completion initiatives to lower costs and improve well productivity and reserves.

HIGHLIGHTS:

- As of March 25, 2011, the Company has 31 gross (22.5 net) producing Cardium horizontal oil wells. Current Cardium production is approximately 1,800 to 1,900 BOED (85% oil and NGL), with an additional 10 gross (7.3 net) Cardium horizontal wells expected to be on production in the second quarter of 2011.
- Current oil and NGL production is approximately 2,450 bpd, up from 1,130 bpd in the first quarter of 2010. Of this number, 1,780 bpd or 73% is crude oil production, compared to 345 bpd or 31% in the first quarter of 2010.
- Year end reserves were 31.7 MMBOE on a proved plus probable (“P&P”) basis, of which 21% were oil and NGL. The reserve life index was 11.5 years. The Company replaced 224% of its production with new P&P reserves and replaced 697% of its oil and NGL production with new oil and NGL P&P reserves.
- Oil & NGL reserves increased from 3.7 MMBOE at the end of 2009 to 6.6 MMBOE on a P&P basis at December 31, 2010. After drilling 22 gross (15.4 net) wells in our first year in the play, Cardium reserves were 2.37 MMBOE of total proved (“TP”) and 4.7 MMBOE of P&P reserves and represent 14.8% of total P&P reserves. The Company expects that the Cardium reserves will continue to grow and become a larger percentage of TP and P&P reserves in future years.
- Finding, development and acquisition costs in 2010, including future development capital, additions and technical revisions but excluding natural gas related economic factors, were \$22.30 per BOE TP and \$22.35 per BOE P&P.
- The Company estimates its net asset value per share to be approximately \$1.78 per share.
- Since the inception of the Cardium horizontal oil program, 37 gross (26.7 net) wells have been drilled with a 100% success rate. In the first quarter of 2011, 15 gross (11.3 net) Cardium horizontal oil wells have been drilled to date, with four drilling rigs still working in the field.
- The Company has increased its Cardium horizontal well prospective lands from its January 17, 2011 update by 10% to 112.5 gross (65.8 net) sections. Based on a drilling density of three wells per section, the Company estimates it could potentially drill 338 gross (197.4 net) Cardium horizontal wells. The Company’s drill ready non-contingent development drilling inventory has increased by 30% since January 17, 2011 to 183 gross (111.2 net) locations.
- The Company has a \$75 million capital budget in 2011 to be spent almost exclusively on the Cardium horizontal oil drilling program. The Company continues to review the commodity price outlook and could potentially expand its 2011 drilling program in the last half of the year with additional Cardium horizontal drilling.

FINANCIAL AND OPERATING HIGHLIGHTS

| (thousands of dollars) | Three months ended December 31, | | % Change | Year ended December 31, | | % Change |
|--|------------------------------------|------------|-------------|----------------------------|-------------|-------------|
| | 2010 | 2009 | | 2010 | 2009 | |
| Oil and gas revenue before royalties ⁽¹⁾ | \$ 23,946 | \$ 20,439 | 17% | \$ 86,457 | \$ 76,993 | 12% |
| Funds from operations | \$ 9,515 | \$ 9,151 | 4% | \$ 37,180 | \$ 31,258 | 19% |
| Funds from operations per share | | | | | | |
| Basic | \$ 0.06 | \$ 0.06 | - | \$ 0.22 | \$ 0.25 | (12%) |
| Diluted | \$ 0.06 | \$ 0.06 | - | \$ 0.22 | \$ 0.25 | (12%) |
| Net loss | \$ (11,741) | \$ (6,457) | (82%) | \$ (35,631) | \$ (36,458) | 2% |
| Net loss per share | | | | | | |
| Basic | \$ (0.07) | \$ (0.04) | (75%) | \$ (0.21) | \$ (0.29) | 28% |
| Diluted | \$ (0.07) | \$ (0.04) | (75%) | \$ (0.21) | \$ (0.29) | 28% |
| Capital expenditures, including acquisitions net of dispositions | \$ 26,473 | \$ 11,312 | 134% | \$ 112,173 | \$ 33,558 | 234% |
| Bank loans plus cash working capital deficiency | | | | \$ 71,507 | \$ 72,524 | (1%) |
| Convertible debentures | | | | \$ 43,460 | \$ - | 100% |
| Shareholders' equity | | | | \$ 333,791 | \$ 332,719 | - |
| Average shares outstanding (thousands) | | | | | | |
| Basic | 172,464 | 150,500 | 15% | 170,298 | 125,047 | 36% |
| Diluted | 172,464 | 150,500 | 15% | 170,298 | 125,047 | 36% |
| Ending shares outstanding (thousands) | | | | 172,485 | 150,500 | 15% |
| Average daily sales | | | | | | |
| Natural gas (Mcf) | 38,479 | 34,938 | 10% | 37,124 | 38,489 | (4%) |
| Liquids (bpd) | 1,815 | 1,257 | 44% | 1,379 | 1,189 | 16% |
| Barrels of oil equivalent (BOED) | 8,228 | 7,080 | 16% | 7,566 | 7,603 | - |
| Average prices | | | | | | |
| Natural gas (\$/Mcf) | \$ 3.48 | \$ 4.28 | (19%) | \$ 3.96 | \$ 3.95 | - |
| Liquids (\$/bbl) ⁽¹⁾ | \$ 69.11 | \$ 53.79 | 28% | \$ 63.24 | \$ 48.22 | 31% |
| Barrels of oil equivalent (\$/BOE) ⁽¹⁾ | \$ 31.63 | \$ 31.38 | 1% | \$ 31.31 | \$ 27.74 | 13% |
| Realized loss on derivative contracts (\$/BOE) | \$ (0.17) | \$ - | (100%) | \$ (0.05) | \$ - | (100%) |
| Royalties (\$/BOE) | \$ 2.98 | \$ 2.66 | 12% | \$ 3.26 | \$ 2.97 | 10% |
| Operating costs (\$/BOE) | \$ 11.62 | \$ 10.49 | 11% | \$ 10.56 | \$ 9.70 | 9% |
| Operating netback (\$/BOE) | \$ 16.86 | \$ 18.23 | (8%) | \$ 17.44 | \$ 15.07 | 16% |
| General and administrative (\$/BOE) | \$ 2.87 | \$ 2.94 | (2%) | \$ 2.80 | \$ 2.52 | 11% |
| Reserves (MBOE) | | | | | | |
| Total proved | | | | 20,117 | 23,615 | (15%) |
| Total proved plus probable | | | | 31,687 | 34,896 | (9%) |
| Wells drilled (gross) | 6 | 107 | (94%) | 49 | 118 | (58%) |
| Undeveloped land (thousands of acres) | | | | | | |
| Gross | | | | 99 | 123 | (20%) |
| Net | | | | 47 | 62 | (24%) |

(1) Excludes realized loss on derivative contracts of \$0.1 million and unrealized loss on derivative contracts of \$1.9 million pertaining to fixed price crude oil swaps recorded in the fourth quarter of 2010.

OPERATIONS:

Cardium Horizontal Oil. In 2010, 22 gross (15.4 net revenue) Cardium horizontal oil wells were drilled. In the fourth quarter of 2010, 6 gross (4.6 net revenue) Cardium horizontal oil wells were drilled. To date in the first quarter of 2011, the Company has drilled 15 gross (11.3 net revenue) Cardium horizontal oil wells, and currently has four drilling rigs still working in the field finishing the remainder of the winter program (4 gross (3.1 net) wells). As of December 31, 2010, the Company had 13.4 net wells producing. Today, 22.5 net Cardium horizontal wells are producing with 7.3 net new Cardium horizontal oil wells expected to be on-stream in the second quarter of 2011. Cardium production was approximately 1,800 to 1,900 BOED (85% oil and NGL) as of March 25, 2011. Oil and NGL production is approximately 2,450 bpd, up substantially from 1,130 bpd in the first quarter of 2010. Of this number, 1,780 bpd or 73% is crude oil production, compared to 345 bpd or 31% in the first quarter of 2010. The Company plans to drill 32 gross (22.0 net capital, 20.0 net revenue) Cardium horizontal oil wells in 2011. A summary of Cardium horizontal well activity since the first quarter of 2010 is shown below:

| <i>Cardium Cumulative Drilling Program</i> | <i>Wells Drilled</i> | | <i>Wells On Production</i> | |
|--|----------------------|------------|----------------------------|------------|
| | <i>Gross</i> | <i>Net</i> | <i>Gross</i> | <i>Net</i> |
| Up to March 25, 2011 | 37 | 26.7 | 31 | 22.5 |
| Estimated up to June 30, 2011 | 41 | 29.8 | 41 | 29.8 |

"Net" is net revenue interest earned.

The Company's Cardium prospective land inventory is 112.5 gross (65.8 net) sections, which has appreciated 10% since the update provided in our January 17, 2011 press release. Based on a development drilling density of three wells per section, the Company estimates it could potentially drill 338 gross (197.4 net) Cardium horizontal wells. From this location list, the Company has advanced 183 gross (111.2 net) horizontal locations to be drilled in the next few years (including wells drilled to date). Each location is a development location that is technically feasible and not contingent upon the drilling of other wells. Successful drilling of these wells and wells being drilled by third parties offsetting Company lands and new land deals have increased the count by 30% since the January 17, 2011 press release. The Company continues to explore opportunities to increase its land position in the play through acquisitions and farm-ins in its existing areas of focus and to improve operating efficiencies in the drilling and completion of wells. A more detailed discussion and review of the Cardium drilling program and go forward plans is shown in the investor presentation at www.andersonenergy.ca.

In February 2011, the Company switched from oil based fracture stimulations to water based fracture stimulations of the Cardium. Well performance has been encouraging and the Company is planning to conduct future fracture stimulations with water. The capital cost savings of this change has been approximately \$500,000 per well. The Company estimates its full cycle drill, complete, equip and tie-in costs for the Cardium horizontal program with water based fracture stimulation to be approximately \$2.8 to \$3.0 million per well.

In 2010, \$6.6 million was spent on the installation of multi-well Cardium oil tank batteries and associated pipelines, some of which will be of use for production from drilling in 2011 and beyond.

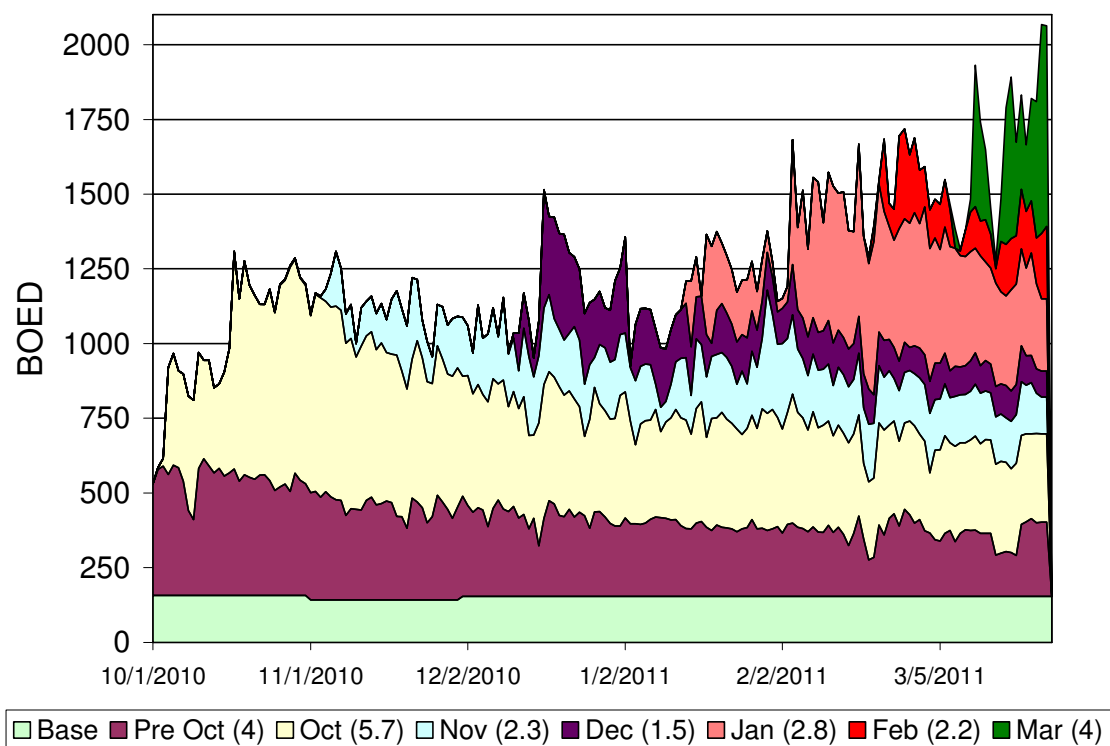
PRODUCTION

For the year ended December 31, 2010, production averaged 7,566 BOED. Production for the fourth quarter of 2010 was 8,228 BOED, up 16% from the same period last year. Oil and NGL production in the fourth quarter of 2010 was 1,815 bpd, up 44% from the same period last year.

Production from the winter drilling program is being brought on-stream in the second half of March and throughout the second quarter of 2011. The production guidance estimate for the 2011 fiscal year is approximately 7,500 BOED. The Company estimates oil and NGL production will be approximately one third of that estimate.

The following graph illustrates the growth in Cardium production since inception of the play in the first quarter of 2010. The graph shows the contribution to production since October 2010 from net wells completed and brought on production in 2010 and to date in 2011. The graph illustrates how the Company has been able to ramp up its Cardium production in the past few months and also illustrates how quickly the production curve stabilizes.

*Cardium Production Growth
(BOED, 85% oil and NGL)*



The numbers in brackets in the legend are the net number of wells included in the data above.

FINANCIAL RESULTS

Capital expenditures were \$112.2 million in 2010 with \$72.9 million spent on drilling and completions and \$40.1 million spent on facilities. This compares to capital expenditures of \$33.6 million in 2009.

Funds from operations were \$37.2 million in 2010 as compared to \$31.3 million in 2009. The average natural gas sales price was \$3.96 per Mcf in 2010 as compared to \$3.95 per Mcf in 2009. Natural gas sales prices in 2010 were \$5.22 per Mcf in the first quarter, \$3.78 per Mcf in the second quarter, \$3.43 per Mcf in the third quarter and \$3.48 per Mcf in the fourth quarter. Natural gas prices continue to be low in the first quarter of 2011. The Company's average crude oil and natural gas liquids sales price in 2010 was \$63.24 per bbl as compared to \$48.22 per bbl in 2009. Operating expenses in 2010 were \$10.56 per BOE, which was 9% higher than \$9.70 per BOE in 2009. Start up costs associated with new Cardium production, various production optimization initiatives, reclassification of co-gen power credits and a large one time compressor repair cost at Buck Lake offset some of the cost savings associated with the Edmonton Sands lower operating cost gas production during 2010. The largest part of these adjustments was recorded in the fourth quarter of the year. The operating netback was \$17.44 per BOE in 2010 as compared to \$15.07 per BOE in 2009. The increase in the operating netback was primarily due to the impact of Cardium horizontal oil production in the fourth quarter of 2010.

In 2011, the Company will be adopting International Financial Reporting Standards. The adoption date of January 1, 2011 requires restatement, for comparative purposes, of amounts reported by the Company for the year ended December 31, 2010, including the opening balance sheet as at January 1, 2010. The changeover will have a significant effect on reported results. The impacts are discussed in more detail in Management's Discussion and Analysis for the year ended December 31, 2010 and we encourage shareholders to look there for more information.

FINANCING

On December 31, 2010, the Company completed a \$50.0 million convertible subordinated debenture financing. The debentures have a five year term with a 7.5% coupon and a conversion price of \$1.55 per share. Proceeds were initially used to reduce the Company's bank indebtedness and provide financial flexibility for its 2011 capital program. The Company closed the sale of \$5.1 million in properties on February 9, 2011. During the first quarter of 2011, the Company also signed agreements to sell surplus drilling incentive credits and other properties for expected proceeds of \$0.4 million. The Company intends to sell a total of \$10 million in assets in 2011. The Company is financing its drilling program with bank loans, convertible debentures, cash flow and dispositions in 2011. The Company has credit facilities of \$125 million with a syndicate of three Canadian banks.

2011 CAPITAL PROGRAM

The Company has a capital budget of \$75 million, net of \$10 million of planned dispositions in 2011, which will be spent almost exclusively on the Cardium oil horizontal drilling program. The Company is planning to drill 32 gross (22 net capital, 20 net revenue) Cardium horizontal oil wells in Central Alberta. At the May 16, 2011 annual shareholder's meeting, the Company will update its shareholders on timing of any potential expansion of the drilling program.

COMMODITY CONTRACTS

The Company has fixed price swaps for 1,000 barrels per day of crude oil for calendar 2011 at a NYMEX crude oil price of Canadian \$88.45 per barrel and for 250 barrels per day of crude oil for calendar 2012 at a NYMEX crude oil price of Canadian \$103.20 per barrel. The Company reviews commodity contracts as part of its price management strategy on an ongoing basis.

RESERVES

GLJ Petroleum Consultants ("GLJ") was engaged to prepare an evaluation of the Company's reserves as of December 31, 2010 in accordance with NI51-101.

A summary of the Company's reserves evaluation is shown below as of December 31, 2010.

| <i>Reserves Category</i> | <i>Natural Gas (Bcf)</i> | <i>Oil (Mbbbls)</i> | <i>Natural Gas Liquids (Mbbbls)</i> | <i>Barrels of Oil equivalent (MBOE)</i> |
|--------------------------------|------------------------------|-------------------------|---|---|
| Proved Developed Producing | 52.5 | 1,303 | 1,376 | 11,428 |
| Proved Developed Non Producing | 7.5 | 168 | 50 | 1,461 |
| Proved Undeveloped | 37.3 | 755 | 247 | 7,228 |
| Total Proved | 97.3 | 2,226 | 1,673 | 20,117 |
| Total Proved plus Probable | 150.6 | 3,908 | 2,676 | 31,687 |

At the end of 2009, the Company had 0.14 MMBOE of TP and 0.47 MMBOE of P&P reserves associated with the Cardium horizontal oil play, representing approximately 1.4% of the total P&P reserves. At the end of 2010, the Company had 2.37 MMBOE of TP and 4.7 MMBOE of P&P reserves associated with the Cardium horizontal oil play, after producing approximately 124.3 MBOE of production in 2010. Today the Cardium represents 14.8% of the Company's P&P reserves. Oil and NGL have grown from 10% of TP and P&P reserves in 2009 to 19% of TP and 21% of P&P reserves in 2010. The Company expects that the Cardium reserves will continue to grow and become a larger percentage of the Company's TP and P&P reserves in future years as the play is

developed. In management's opinion, the GLJ report is conservative on Cardium oil reserves as this is the first year an independent evaluation has been prepared on this new and emerging play for the Company.

The Company's reserve life indices are 7.3 years TP and 11.5 years P&P, based on 2010 annual production. In 2010, the Company replaced 224% of production with new P&P reserves additions, net of technical revisions. The Company replaced 697% of its oil and NGL production with new P&P oil and NGL reserves.

Proved developed producing ("PDP") reserves grew 24% in 2010. The PDP net present value at a 10% pre-tax discount rate ("NPV 10") increased 6% in 2010. Reserves grew due to positive additions and revisions in both natural gas and oil. The percentage of PDP reserves relating to oil and NGL was 23% in 2010 compared to 18% in 2009. The PDP NPV 10 value was negatively impacted by reductions in forecast natural gas prices.

In 2010, the Company experienced positive technical revisions of 3.3 MMBOE TP and 0.3 MMBOE P&P. These were offset by negative economic factors of 7.1 MMBOE TP and 6.6 MMBOE P&P. Almost the entire economic factor related to the undeveloped gas and NGL reserves in the Edmonton Sands. The economic factor was due to a 25% reduction in GLJ's natural gas price outlook for the years 2011 to 2015, and 16% thereafter. This was partially offset by the fact that there was improved performance in the proved developed producing category for the Edmonton Sands resulting in positive additions and revisions of 2.2 MMBOE.

The Company's 2010 finding, development and acquisition costs ("FD&A") for additions only were \$17.56 per BOE TP and \$15.81 per BOE P&P. FD&A, including future development capital and additions and technical revisions but excluding economic factors, were \$22.30 per BOE TP and \$22.35 per BOE P&P. The Company's 2010 FD&A costs were higher than in 2009, as the Company's capital investments were geared to starting up the more capital intensive Cardium horizontal oil drilling program, building Cardium multi-well batteries and completing its 2009/2010 winter shallow gas drilling program. With a WTI oil price of \$100 US, the Cardium wellhead operating netback is approximately \$75 per BOE and the \$22.35 per BOE FD&A is very acceptable, providing a recycle ratio of 3.3 times. Management's Discussion and Analysis contains more details on the calculation of FD&A costs.

| | <i>Total Proved Developed Producing</i> | <i>Total Proved (MBOE)</i> | <i>Total Proved plus Probable</i> |
|------------------------------------|---|--------------------------------|---------------------------------------|
| Opening Balance, December 31, 2009 | 9,223 | 23,615 | 34,896 |
| Additions | 3,270 | 3,023 | 5,913 |
| Technical revisions | 2,124 | 3,318 | 269 |
| Production | (2,761) | (2,761) | (2,761) |
| Economic factors | (428) | (7,078) | (6,630) |
| Closing Balance, December 31, 2010 | 11,428 | 20,117 | 31,687 |

NET ASSET VALUATION ¹ As at December 31, 2010

(\$ millions, unless otherwise stated)

| | |
|--|---------|
| P&P reserves (pretax 10% discount rate) | \$ 271 |
| Undeveloped land (excluding Cardium horizontal prospective lands) | 5 |
| Cardium horizontal prospective lands | 166 |
| Stock option proceeds | 6 |
| Bank loans plus cash working capital deficiency | (71) |
| Net asset value estimate, December 31, 2010 | \$ 377 |
| Net asset value estimate per fully diluted share, December 31, 2010* | \$ 1.78 |

* based on 211.3 million outstanding shares on a fully diluted basis

¹ The net asset valuation shows what the Corporation's reserves would be produced at using forecast prices and costs. The value is a snapshot in time and based on various assumptions including commodity prices that vary over time. It should not be assumed that NAV represents the fair market value of Anderson Energy shares.

It was assumed in the NAV calculation that the convertible debenture would be converted at \$1.55 per share and the outstanding shares were adjusted accordingly.

The GLJ price forecast as of December 31, 2010 is shown in Management's Discussion and Analysis for the year ended December 31, 2010. Complete reserves disclosure as required under NI 51-101 will be contained in the Company's 2010 Annual Information Form, to be filed on SEDAR by March 31, 2011.

The Company has 98,813 gross (47,300 net) undeveloped acres of land excluding Cardium horizontal prospective land as of December 31, 2010 and has assigned a value of \$5.0 million to this acreage position. The Company used a \$3.0 million per net section valuation for Cardium lands that were not assigned drilling locations in the GLJ reserves report. The Company believes that these locations were not assigned reserves as there was insufficient production or horizontal well control to book reserves under the criteria of NI51-101, and/or the locations were picked based on land deals done after December 31, 2010. The Company's engineers have estimated the potential net present value of an average unbooked Cardium location to be approximately \$2.2 million per location, using GLJ's price forecast, a 10% pretax discount rate, farm-in and straight up economics over a four year time span of drilling activity. The Company has an inventory of 74.7 net Cardium locations not booked in the GLJ reserves report.

As of March 25, 2011, the Company's drill ready non-contingent development Cardium horizontal drilling inventory is as follows:

| <i>Cardium Locations</i> | <i>Gross</i> | <i>Net</i> |
|-----------------------------|--------------|-------------|
| Inventory at March 25, 2011 | 183 | 111.2 |
| Drilled to March 25, 2011 | (37) | (26.7) |
| Remaining | <u>146</u> | <u>84.5</u> |

OUTLOOK

The last two years have been very difficult in the natural gas business, and 2011 does not currently look like it will be much better. Oil prices continue to remain strong due increasing demand and ongoing geopolitical events in the world. The Company's response to a very weak and uncertain gas price environment was to switch its capital program to light oil horizontal drilling. The Company was able to position itself and make the switch in the last half of 2010. The Company was able to move up the learning curve in the Cardium play in 2010 and in the first quarter of 2011 with its drilling, completion and production initiatives. The Company is very focused on increasing its land position in the Cardium and utilizing new technologies to lower costs and enhance well performance. The addition of water based fracture stimulation in February 2011 is one example of new initiatives. At WTI oil prices of \$100 U.S. per bbl, operating netbacks in the Cardium program are approximately \$75.00 per BOE as compared to operating netbacks in the Edmonton Sands shallow gas program of \$15.00 per BOE.

Current oil & NGL production is approximately 2,450 bpd and the Company's goal is grow its oil production to achieve 50% of total production being oil and NGL production by early 2012. By the second quarter of this year, the Company will have drilled and brought on production 41 gross (29.8 net) Cardium oil horizontal wells. The Company has increased its Cardium development drilling inventory by 30% in the past few months and is becoming one of the industry leaders in lower capital costs. The Company believes it is well positioned in the Cardium horizontal oil play and the results from the winter drilling program will help in peeling the natural gas label off the Company's stock price and reward the shareholders with more of an oil company evaluation.

The Company will be assessing the potential to increase its 2011 capital program in the second quarter.

PEOPLE

On February 28, 2011, Patrick O'Rourke joined the Company as Vice President of Production. Patrick is a professional engineer with 22 years of experience in both technical and managerial positions in facilities and

production engineering. Patrick will be focused on optimizing our new Cardium oil production and reducing overall operating expenses in 2011. We welcome Patrick to the management team.

2010 was a year of repositioning. The Company would like to thank its shareholders and its employees for their support throughout this year of transition. The Company invites its shareholders to attend the annual meeting on May 16, 2011 at the Metropolitan Centre in Calgary, Alberta at 2:00 pm MDT and encourages anyone interested in further details to visit the Company's website at www.andersonenergy.ca.

Brian H. Dau
President & Chief Executive Officer
March 28, 2011

Management's Discussion and Analysis

FOR THE YEARS ENDED DECEMBER 31, 2010 AND 2009

The following discussion and analysis of financial results should be read in conjunction with the audited consolidated financial statements of Anderson Energy Ltd. ("Anderson Energy" or the "Company") for the years ended December 31, 2010 and 2009 and is based on information available as of March 25, 2011.

The following information is based on financial statements prepared by management in accordance with Canadian generally accepted accounting principles ("GAAP"). Production and reserves numbers are stated before deducting Crown or lessor royalties.

Included in the discussion and analysis are references to terms commonly used in the oil and gas industry such as funds from operations, finding, development and acquisition ("FD&A") costs, operating netback and barrels of oil equivalent ("BOE"). Funds from operations as used in this report represent cash from operating activities before changes in non-cash working capital and asset retirement expenditures. See "Review of Financial Results – Funds from Operations" for details of this calculation. Funds from operations represent both an indicator of the Company's performance and a funding source for on-going operations. FD&A costs measure the cost of reserves additions and are an indicator of the efficiency of capital expended in the period. Operating netback is calculated as oil and gas revenues less royalties and operating expenses and is a measure of the profitability of operations before administrative and financing expenditures. Production volumes and reserves are commonly expressed on a BOE basis whereby natural gas volumes are converted at the ratio of six thousand cubic feet to one barrel of oil. The intention is to sum oil and natural gas measurement units into one basis for improved analysis of results and comparisons with other industry participants. These terms are not defined by Canadian GAAP and therefore are referred to as non-GAAP measures.

All references to dollar values are to Canadian dollars unless otherwise stated.

Definitions of the abbreviations used in this discussion and analysis are located on the last page of this document.

REVIEW OF FINANCIAL RESULTS

Overview. For the year ended December 31, 2010, funds from operations were \$37.2 million (\$0.22 per share), up 19% from 2009 as a result of the Company's refocus on Cardium light oil drilling. Sales volumes averaged 7,566 BOED, similar to the previous year.

Capital additions, net of dispositions were \$112.2 million for the year ended December 31, 2010. During the year, the Company drilled 22 gross (16.3 net capital) Cardium horizontal light oil wells, four gross (4.0 net) Rock Creek deep gas wells, two gross (1.1 net) Ellerslie deep gas wells and two gross (2.0 net) Whitemud horizontal wells with a 100% success rate. In the first quarter of 2010, the Company drilled 19 gross (14.7 net) Edmonton Sands wells with a 79% success rate. The Company tied in 13 gross (10.0 net) Cardium horizontal light oil wells and seven gross (4.5 net) Edmonton Sands shallow gas wells in the fourth quarter of 2010. The Company has deferred the drilling of the remaining 74 Edmonton Sands gas wells under its farm-in agreement until the first quarter of 2012. The Company's finding, development and acquisition costs, net of the change in future development capital and before economic factors was \$22.35 per BOE on a proved plus probable basis for 2010.

Bank loans plus the working capital deficiency before the unrealized loss on derivative contracts and future income tax asset was \$71.5 million at December 31, 2010. Total bank facilities are currently \$125 million. On December 31, 2010, the Company completed a convertible subordinated debenture financing for proceeds, net of commission and expenses, of \$47.7 million. Proceeds were initially used to pay down bank debt. The availability created in the credit facilities, along with cash flows, will be used to help finance the Company's 2011 capital program.

Revenue and Production. In 2010, the Company changed its focus to oil prospects in light of the depressed natural gas market. Oil and natural gas liquids revenue went from 27% of total revenue in the first quarter of 2010 to 48% of total revenue in the fourth quarter of 2010.

Gas sales volumes for the year ended December 31, 2010 decreased to an average of 37.1 MMcfd from 38.5 MMcfd last year due to the suspension of shallow gas drilling after the first quarter. The central Alberta area, centered around the Sylvan Lake area and northwest to Pembina, remains the Company's largest area of production, with gas sales averaging 35.6 MMcfd (36.7 MMcfd during 2009).

Gas sales volumes averaged 38.5 MMcfd in the fourth quarter of 2010 compared to 35.8 MMcfd in the third quarter of 2010 and 34.9 MMcfd in the fourth quarter of 2009. The increase in the gas volumes from the third quarter of 2010 resulted from the tie-in of natural gas wells drilled earlier in the year, as well as the shallow gas fit for purpose processing facilities in the Medicine River area being fully operational throughout the fourth quarter of 2010.

Oil sales for the year ended December 31, 2010 averaged 601 bpd compared to 395 bpd for the year ended December 31, 2009. Oil production averaged 992 bpd in the fourth quarter of 2010 compared to 568 bpd in the third quarter of 2010 and 351 bpd in the fourth quarter of 2009. The increase in volumes is due to new oil production from 17 gross (11.0 net) Cardium horizontal light oil wells which were brought on production during the fourth quarter of 2010. There were no oil wells drilled in 2009.

Natural gas liquids sales for the year ended December 31, 2010 averaged 778 bpd compared to 794 bpd for the year ended December 31, 2009. Natural gas liquids sales averaged 823 bpd in the fourth quarter of 2010 compared to 761 bpd in the third quarter of 2010 and 906 bpd in the fourth quarter of 2009. The increase in sales volumes in the fourth quarter of 2010 is due to well tie-ins occurring late in the third quarter of 2010 at Westpem.

The following tables outline production revenue, volumes and average sales prices for the three and twelve months ended December 31, 2010 and 2009.

OIL AND NATURAL GAS REVENUE

| (thousands of dollars) | Three months ended December 31 | | Year ended December 31 | |
|---|-----------------------------------|-----------|---------------------------|-----------|
| | 2010 | 2009 | 2010 | 2009 |
| Natural gas | \$ 12,320 | \$ 13,754 | \$ 52,304 | \$ 55,426 |
| Gain on fixed price natural gas contracts | - | - | 1,302 | - |
| Total natural gas | 12,320 | 13,754 | 53,606 | 55,426 |
| Oil ⁽¹⁾ | 7,081 | 2,247 | 16,142 | 8,540 |
| NGL | 4,459 | 3,973 | 15,672 | 12,375 |
| Royalty and other | 86 | 465 | 1,037 | 652 |
| Total revenue ⁽¹⁾ | \$ 23,946 | \$ 20,439 | \$ 86,457 | \$ 76,993 |

⁽¹⁾ Excludes realized loss on derivative contracts of \$0.1 million and unrealized loss on derivative contracts of \$1.9 million pertaining to fixed price crude oil swaps recorded in the fourth quarter of 2010.

PRODUCTION

| | Three months ended December 31 | | Year ended December 31 | |
|---------------------|-----------------------------------|--------------|---------------------------|--------------|
| | 2010 | 2009 | 2010 | 2009 |
| Natural gas (Mcf) | 38,479 | 34,938 | 37,124 | 38,489 |
| Oil (bpd) | 992 | 351 | 601 | 395 |
| NGL (bpd) | 823 | 906 | 778 | 794 |
| Total (BOED) | 8,228 | 7,080 | 7,566 | 7,603 |

PRICES

| | Three months ended December 31 | | Year ended December 31 | |
|--|-----------------------------------|-----------------|---------------------------|-----------------|
| | 2010 | 2009 | 2010 | 2009 |
| Natural gas (\$/Mcf) ⁽¹⁾ | \$ 3.48 | \$ 4.28 | \$ 3.96 | \$ 3.95 |
| Oil (\$/bbl) ⁽²⁾ | 77.62 | 69.60 | 73.62 | 59.26 |
| NGL (\$/bbl) | 58.87 | 47.67 | 55.22 | 42.73 |
| Total (\$/BOE)⁽²⁾⁽³⁾ | \$ 31.63 | \$ 31.38 | \$ 31.31 | \$ 27.74 |

(1) Includes gain on fixed price natural gas contracts of \$1.3 million from the first quarter of 2010.

(2) Excludes realized loss on derivative contracts of \$0.1 million and unrealized loss on derivative contracts of \$1.9 million pertaining to fixed price crude oil swaps recorded in the fourth quarter of 2010.

(3) Includes royalty and other income classified with oil and gas sales.

Anderson Energy's average gas sales price was \$3.96 per Mcf for the year ended December 31, 2010 compared to \$3.95 per Mcf for the year ended December 31, 2009. For the three months ended December 31, 2010, the gas sales price was \$3.48 per Mcf compared to \$3.43 per Mcf realized in the third quarter of 2010 and \$4.28 per Mcf in the fourth quarter of 2009. Gas prices were significantly affected by increased supply and lower industrial consumption of natural gas in the United States. Prices were higher in the last quarter of 2009 and first quarter of 2010, but remained low for the remainder of 2010. The natural gas price in 2010 includes a gain on fixed price natural gas contracts of \$1.3 million. The 2010 natural gas price before the gain was \$3.86 per Mcf. The oil price in 2010 does not include a realized loss on derivative contracts of \$0.1 million. The realized oil price including this loss was \$76.18 per barrel for the fourth quarter of 2010 and \$73.02 per barrel for the year ended December 31, 2010.

The Company is currently selling all of its gas production at the average daily index price. The Company has classified all transportation costs as an offset to gas sales revenue as title transfers prior to transport on the applicable sales pipelines and transportation is being held by and charged by the gas purchasers. The Company has arranged firm service transportation agreements covering approximately 29 MMcfd of natural gas sales for various terms ranging from one to ten years.

Commodity Contracts. In October 2010, as part of its risk management program, the Company entered into fixed price swap contracts for 1,000 barrels per day of crude oil for December 2010 at a NYMEX crude oil price of Canadian \$85.70 per barrel and for calendar 2011 at a NYMEX crude oil price of Canadian \$88.45 per barrel. In 2010, these contracts had the following impact on the consolidated statements of operations:

| (thousands of dollars) | Three months ended December 31 | | Year ended December 31 | |
|---|--------------------------------|-------------|------------------------|-------------|
| | 2010 | 2009 | 2010 | 2009 |
| Realized loss on derivative contracts | \$ (131) | \$ - | \$ (131) | \$ - |
| Unrealized loss on derivative contracts | (1,918) | - | (1,918) | - |
| | \$ (2,049) | \$ - | \$ (2,049) | \$ - |

In March 2011, the Company entered into a fixed price swap contract for 250 barrels per day of crude oil for calendar 2012 at a NYMEX crude oil price of Canadian \$103.20 per barrel.

The Company had no fixed price natural gas contracts in place at December 31, 2010.

Royalties. Royalties were 10.4% of revenue for the year ended December 31, 2010 compared to 10.7% of revenue for the year ended December 31, 2009. Royalties were 9.4% of revenue in the fourth quarter of 2010 compared to 8.8% of revenue in the third quarter of 2010 and 8.5% of revenue in the fourth quarter of 2009. The increase in the royalty rate in the fourth quarter of 2010 is due to an estimated reduction in gas cost allowance for 2010 as a result of lower crown royalties and lower facility effective royalty rates expected to be used in the annual assessment. This increase was partially offset by the decline in the gross crown royalty rate due to a larger percentage of royalties calculated at the 5% royalty rate for new production.

Royalties as a percentage of revenue are highly sensitive to prices and adjustments to gas cost allowance and so royalty rates can fluctuate from quarter to quarter. In addition, when prices and corresponding revenues are lower, fixed monthly gas cost allowance becomes more significant to the overall royalty rate. On January 1, 2009, the Alberta government's New Royalty Framework came into effect. The Alberta government revised the royalty regime in March 2009, and again in March 2010, for new wells tied in on Crown lands. Producers will pay a reduced Crown royalty rate of 5% for the first year on up to 500 MMcf of gas production or up to 50 Mstb of oil production. In addition, the Alberta government changed the maximum royalty payable on oil from 50% to 40% and on natural gas from 50% to 36%. Other important changes positively impact the Company's refocused horizontal oil program, where based on the measured depth of the well, the Company will pay the Crown a 5% royalty for 24 to 30 months for up to 60 to 70 Mstb of oil production. The majority of the Company's horizontal program on Crown lands would qualify for the 30 months of 5% royalty for up to 70 Mstb of oil production.

| | Three months ended December 31 | | Year ended December 31 | |
|--------------------------|--------------------------------|---------|------------------------|---------|
| | 2010 | 2009 | 2010 | 2009 |
| Gross crown royalties | 10.9% | 15.3% | 12.5% | 15.4% |
| Gas cost allowance | (3.7%) | (10.8%) | (7.2%) | (11.1%) |
| Other royalties | 2.2% | 4.0% | 5.1% | 6.4% |
| Total royalties | 9.4% | 8.5% | 10.4% | 10.7% |
| Total royalties (\$/BOE) | \$ 2.98 | \$ 2.66 | \$ 3.26 | \$ 2.97 |

Operating Expenses. Operating expenses were \$10.56 per BOE for the year ended December 31, 2010 compared to \$9.70 per BOE for the year ended December 31, 2009. Operating expenses were \$11.62 per BOE in the fourth quarter of 2010 compared to \$9.71 per BOE in the third quarter of 2010 and \$10.49 per BOE in the fourth quarter of 2009. Start up costs associated with new Cardium production, various production optimization initiatives, reclassification of co-gen power credits and a large one time compressor repair cost at Buck Lake offset some of the cost savings associated with the Edmonton Sands lower operating cost gas production during 2010.

OPERATING NETBACK

| (thousands of dollars) (⁽¹⁾) | Three months ended December 31 | | Year ended December 31 | |
|--|--------------------------------|------------------|------------------------|------------------|
| | 2010 | 2009 | 2010 | 2009 |
| Revenue | \$ 23,946 | \$ 20,439 | \$ 86,457 | \$ 76,993 |
| Realized loss on derivative contracts | (131) | - | (131) | - |
| Royalties | (2,256) | (1,731) | (9,011) | (8,253) |
| Operating expenses | (8,799) | (6,831) | (29,148) | (26,906) |
| | <u>\$ 12,760</u> | <u>\$ 11,877</u> | <u>\$ 48,167</u> | <u>\$ 41,834</u> |
| Sales (MBOE) | 757.0 | 651.4 | 2,761.5 | 2,775.2 |
| Per BOE | | | | |
| Revenue (⁽¹⁾) | \$ 31.63 | \$ 31.38 | \$ 31.31 | \$ 27.74 |
| Realized loss on derivative contracts | (0.17) | - | (0.05) | - |
| Royalties | (2.98) | (2.66) | (3.26) | (2.97) |
| Operating expenses | (11.62) | (10.49) | (10.56) | (9.70) |
| | <u>\$ 16.86</u> | <u>\$ 18.23</u> | <u>\$ 17.44</u> | <u>\$ 15.07</u> |

(1) Includes royalty and other income classified with oil and gas sales. Excludes unrealized loss on derivative contracts of \$1.9 million pertaining to fixed price crude oil swaps recorded in the fourth quarter of 2010.

General and Administrative Expenses. General and administrative expenses were \$7.7 million or \$2.80 per BOE for the year ended December 31, 2010 compared to \$7.0 million or \$2.52 per BOE for the year ended December 31, 2009. General and administrative expenses were \$2.87 per BOE in the fourth quarter of 2010 compared to \$2.82 per BOE in the third quarter of 2010 and \$2.94 per BOE in the fourth quarter of 2009. In light of a more competitive labour market in 2010, the Company reversed the salary cutbacks taken in 2009 and reinstated its employee stock savings plan effective April 1, 2010. The Company also accrued additional bonuses for employees in the fourth quarter of 2010 in acknowledgement of employee efforts in refocusing the Company in 2010.

| (thousands of dollars) | Three months ended December 31 | | Year ended December 31 | |
|-------------------------------------|--------------------------------|-----------------|------------------------|-----------------|
| | 2010 | 2009 | 2010 | 2009 |
| General and administrative (gross) | \$ 4,082 | \$ 3,276 | \$ 13,742 | \$ 12,284 |
| Overhead recoveries | (570) | (437) | (1,751) | (1,721) |
| Capitalized | (1,339) | (924) | (4,258) | (3,565) |
| General and administrative (net) | <u>\$ 2,173</u> | <u>\$ 1,915</u> | <u>\$ 7,733</u> | <u>\$ 6,998</u> |
| General and administrative (\$/BOE) | \$ 2.87 | \$ 2.94 | \$ 2.80 | \$ 2.52 |
| % Capitalized | 33% | 28% | 31% | 29% |

Capitalized general and administrative costs are limited to salaries and associated office rent of staff involved in capital activities.

Stock-Based Compensation. The Company accounts for stock-based compensation plans using the fair value method of accounting. Stock-based compensation expense was \$2.1 million in 2010 (\$1.2 million net of amounts capitalized) versus \$2.1 million (\$1.1 million net of amounts capitalized) in 2009. Stock-based compensation costs were \$0.4 million for the fourth quarter of 2010 (\$0.3 million net of amounts capitalized) versus \$0.4 million (\$0.2 million net of amounts capitalized) in the fourth quarter of 2009.

Interest Expense. In the fourth quarter of 2010, interest expense was \$1.1 million compared to \$0.8 million in the third quarter of 2010 and \$0.8 million in the fourth quarter of 2009. The increase in interest expense from the third quarter of 2010 is due to the higher average debt levels. Interest expense was \$3.4 million for the year ended December 31, 2010 compared to \$3.7 million in 2009. The decrease in interest expense from the comparable 2009 period is due to lower average debt levels in 2010 partially offset by increases in interest rates. The average effective interest rate on outstanding bank loans was 4.9% in 2010 compared to 4.2% in 2009.

Depletion and Depreciation. Depletion and depreciation was \$78.7 million (\$28.51 per BOE) for the year ended December 31, 2010 compared to \$78.6 million (\$28.33 per BOE) in 2009. Depletion and depreciation was \$22.2 million (\$29.38 per BOE) in the fourth quarter of 2010 compared to \$18.9 million (\$28.23 per BOE) in the third quarter of 2010 and \$17.2 million (\$26.39 per BOE) in the fourth quarter of 2009. Depletion and depreciation expense is calculated based on proved reserves only. Fourth quarter depletion and depreciation is calculated using the new reserves evaluation and incorporates a decrease in total proved natural gas reserves.

Asset Retirement Obligation. The Company recorded a \$1.4 million increase in asset retirement obligations in 2010 (\$0.3 million the fourth quarter of 2010) related to current activity and changes in estimates. Accretion expense was \$2.5 million for 2010 compared with \$2.3 million for 2009. Accretion expense was included in depletion and depreciation expense and increased due to the higher obligations.

Income Taxes. Anderson Energy is not currently taxable. The Company does not anticipate paying current income tax in 2011. The estimated tax pool balances at December 31, 2010 are summarized below. Non-capital losses are estimated assuming full claims for CDE, COGPE and UCC are made in the current year. Tax pool classifications are estimates as some new wells have not yet had their status as exploratory or development confirmed. The balances below have been reduced for the effect of income recorded in 2010 that will not be taxed until 2011.

| | | |
|--|----|--------------------|
| Canadian Exploration Expenses (CEE) | \$ | 66 million |
| Canadian Development Expenses (CDE) | | 126 million |
| Undepreciated Capital Cost (UCC) | | 108 million |
| Canadian Oil and Gas Property Expenses (COGPE) | | 12 million |
| Non-Capital Losses and Other | | <u>78 million</u> |
| Total | \$ | <u>390 million</u> |

Funds from Operations. Funds from operations increased by 19% to \$37.2 million in 2010 compared to \$31.3 million in 2009. On a per share basis, funds from operations were \$0.22 per share in 2010 compared to \$0.25 per share in 2009. For the three months ended December 31, 2010, funds from operations were \$9.5 million or \$0.06 per share, an increase of 19% over the previous quarter of \$8.0 million or \$0.05 per share, and an increase of 4% from the fourth quarter of 2009 of \$9.2 million or \$0.06 per share. Funds from operations increased as the Company refocused its capital initiatives on oil prospects, which are brought on production at significantly higher expected operating margins. In the fourth quarter of 2010, oil and NGLs accounted for \$11.5 million or 48% of revenue compared to \$7.2 million or 38% in the third quarter of 2010 and \$6.2 million or 30% in the fourth quarter of 2009.

| (thousands of dollars) | Three months ended December 31 | | Year ended December 31 | |
|-------------------------------------|-----------------------------------|-----------------|---------------------------|------------------|
| | 2010 | 2009 | 2010 | 2009 |
| Cash from operating activities | \$ 10,721 | \$ 5,361 | \$ 40,996 | \$ 23,820 |
| Changes in non-cash working capital | (1,324) | 3,246 | (5,365) | 5,956 |
| Asset retirement expenditures | <u>118</u> | <u>544</u> | <u>1,549</u> | <u>1,482</u> |
| Funds from operations | <u>\$ 9,515</u> | <u>\$ 9,151</u> | <u>\$ 37,180</u> | <u>\$ 31,258</u> |

Earnings. The Company reported an \$11.7 million net loss in the fourth quarter of 2010 compared to a net loss \$9.0 million in the third quarter of 2010 and \$6.5 million in the fourth quarter of 2009. Earnings were lower in the fourth quarter of 2010 compared to the previous

quarter as a result of higher depletion due to a reduction in proved natural gas reserves. The Company reported a net loss of \$35.6 million in 2010 compared to a net loss of \$36.5 million in 2009. As with funds from operations, earnings continue to be impacted by low natural gas prices. The change in the Company's focus to crude oil, with its currently higher operating margins, is expected to improve future earnings.

The Company's funds from operations and earnings are highly sensitive to changes in factors that are beyond its control. An estimate of the Company's sensitivities to changes in commodity prices, exchange rates and interest rates is summarized below:

SENSITIVITIES

| | <i>Funds from Operations</i> | | <i>Earnings</i> | |
|---------------------------------------|------------------------------|------------------|-----------------|------------------|
| | <i>Millions</i> | <i>Per Share</i> | <i>Millions</i> | <i>Per Share</i> |
| \$0.50/Mcf in price of natural gas | \$ 6.4 | \$ 0.04 | \$ 4.8 | \$ 0.03 |
| US \$5.00/bbl in the WTI crude price | \$ 1.8 | \$ 0.01 | \$ 1.4 | \$ 0.01 |
| US \$0.01 in the US/Cdn exchange rate | \$ 0.8 | \$ 0.00 | \$ 0.6 | \$ 0.00 |
| 1% in short-term interest rate | \$ 0.4 | \$ 0.00 | \$ 0.3 | \$ 0.00 |

This sensitivity analysis was calculated by applying different pricing, interest rate and exchange rate assumptions to the 2010 actual results related to production, prices, royalty rates, operating costs and capital spending. As the Company changes its focus to crude oil development, the impact of oil prices is expected to become more significant and the impact of natural gas prices is expected to become less significant to funds from operations and earnings than is shown in the table above.

CAPITAL EXPENDITURES

The Company spent \$26.5 million in capital expenditures, net of dispositions and drilling incentive credits, in the fourth quarter of 2010 and \$112.2 million for the year ended December 31, 2010. The breakdown of expenditures is shown below:

| <i>(thousands of dollars)</i> | <i>Three months ended December 31</i> | | <i>Year ended December 31</i> | |
|--|---|-------------|-----------------------------------|-------------|
| | <i>2010</i> | <i>2009</i> | <i>2010</i> | <i>2009</i> |
| Land, geological and geophysical costs | \$ (11) | \$ (15) | \$ 416 | \$ 173 |
| Acquisitions, net of dispositions | 299 | - | (464) | (54) |
| Drilling, completion and recompletion | 19,336 | 15,492 | 72,873 | 23,952 |
| Drilling incentive credits | 162 | (6,000) | (3,455) | (6,000) |
| Facilities and well equipment | 6,297 | 3,642 | 40,079 | 11,349 |
| Capitalized G&A | 1,339 | 924 | 4,258 | 3,565 |
| Total finding, development & acquisition expenditures | 27,422 | 14,043 | 113,707 | 32,985 |
| Change in compressor and other equipment inventory | (957) | (2,736) | (1,601) | 542 |
| Office equipment and furniture | 8 | 5 | 67 | 31 |
| Total capital expenditures | 26,473 | 11,312 | 112,173 | 33,558 |
| Non-cash asset retirement obligations and capitalized stock-based compensation | 504 | 2,003 | 2,369 | 3,220 |
| Total cash and non-cash capital additions | \$ 26,977 | \$ 13,315 | \$ 114,542 | \$ 36,778 |

Drilling statistics are shown below:

| | Three months ended December 31 | | | | Year ended December 31 | | | |
|------------------|--------------------------------|------------|------------|-------------|------------------------|-------------|------------|-------------|
| | 2010 | | 2009 | | 2010 | | 2009 | |
| | Gross | Net | Gross | Net | Gross | Net | Gross | Net |
| Gas | - | - | 98 | 73.6 | 23 | 19.0 | 109 | 81.9 |
| Oil | 6 | 5.1 | - | - | 22 | 16.3 | - | - |
| Dry | - | - | 9 | 7.6 | 4 | 2.8 | 9 | 7.6 |
| Total | 6 | 5.1 | 107 | 81.2 | 49 | 38.1 | 118 | 89.5 |
| Success rate (%) | 100% | 100% | 92% | 91% | 92% | 93% | 92% | 92% |

For the year ended December 31, 2010, the Company drilled 22 gross (16.3 net capital) Cardium horizontal light oil wells. Of the 22 gross well drilled, the Company drilled six gross (5.1 net capital) Cardium horizontal light oil wells in the fourth quarter of 2010. The Company has not drilled any vertical Edmonton Sands shallow gas wells since the first quarter of 2010. In 2010, the Company tied in 97 gross (65.7 net) Edmonton Sands shallow gas wells, of which seven gross (4.5 net) were tied-in in the fourth quarter of 2010. The Company also brought 20 gross (14.3 net capital) Cardium horizontal light oil wells on-stream during 2010, of which 13 gross (10.0 net) well were brought on-stream in the fourth quarter. In addition, the Company tied in four gross (4.0 net) Rock Creek wells during 2010. In 2009, the Company drilled 118 gross (89.5 net) Edmonton Sands wells of which 107 gross (81.2 net) wells were drilled in the fourth quarter under a large scale farm-in.

In the fourth quarter of 2009, the Company accrued \$6.0 million for drilling incentive credits. Drilling credits earned are capped at 50% of crown royalties paid between April 1, 2009 and March 31, 2011 and the Company estimates that it will earn more drilling credits than it will be able to claim. These credits are expected to be paid out between 2009 and 2011 as crown royalties are paid. The estimate is highly dependent on commodity prices, production levels, crown royalty rates and gas cost allowance earned over this period. To the extent that crown royalties paid are lower or higher, drilling credits will be lower or higher as well. As a result of the cap, the Company reduced its accrual by \$1.0 million in the fourth quarter of 2010 and did not accrue any additional drilling credits related to drilling in 2010. The Company received \$4.5 million in proceeds on the sale of some of these surplus credits in 2010.

CEILING TEST

At December 31, 2010, the ceiling test resulted in the discounted cash flows from proved plus probable reserves being in excess of the carrying value of the underlying petroleum and natural gas assets and as such no ceiling test write-down was required. See "Reserves – Summary of Pricing and Inflation Rate Assumptions" for the prices used in the 2010 ceiling test.

RESERVES

The Company's reserves were evaluated by GLJ Petroleum Consultants ("GLJ") in accordance with National Instrument 51-101 ("NI 51-101") as of December 31, 2010. The tables in this section are an excerpt from what will be contained in the Company's Annual Information Form for the year ended December 31, 2010 ("AIF") as the Company's NI 51-101 annual required filings.

SUMMARY OF GROSS OIL AND GAS RESERVES

As at December 31, 2010

| | Natural Gas ⁽¹⁾ (MMcf) | Oil ⁽¹⁾ (Mbbbls) | Natural Gas Liquids (Mbbbls) | Total BOE (MBOE) |
|--------------------------------|--------------------------------------|--------------------------------|------------------------------------|---------------------|
| Proved developed producing | 52,498 | 1,303 | 1,376 | 11,428 |
| Proved developed non-producing | 7,457 | 168 | 50 | 1,461 |
| Proved undeveloped | 37,358 | 755 | 247 | 7,228 |
| Total proved | 97,313 | 2,226 | 1,673 | 20,117 |
| Probable | 53,308 | 1,682 | 1,003 | 11,570 |
| Total proved plus probable | 150,621 | 3,908 | 2,676 | 31,687 |

(1) Coal Bed Methane is not material to report separately and is included in the Natural Gas category. Heavy Oil is not material to report separately and is included in the Oil category.

NET PRESENT VALUE BEFORE INCOME TAXES

As at December 31, 2010

GLJ December 31, 2010 Price Forecast, Escalated Prices

| (thousands of dollars) | 0% | 5% | 10% | 15% | 20% |
|--------------------------------|---------|---------|---------|---------|---------|
| Proved developed producing | 252,854 | 196,268 | 166,058 | 145,193 | 129,562 |
| Proved developed non-producing | 19,167 | 13,331 | 9,561 | 6,988 | 5,154 |
| Proved undeveloped | 52,833 | 24,954 | 8,629 | (1,310) | (7,520) |
| Total proved | 324,854 | 234,553 | 184,248 | 150,870 | 127,197 |
| Probable | 231,850 | 136,742 | 87,221 | 58,520 | 40,543 |
| Total proved plus probable | 556,704 | 371,295 | 271,469 | 209,391 | 167,739 |

The estimated net present value of future net revenues presented in the table above does not necessarily represent the fair market value of the Company's reserves.

SUMMARY OF PRICING AND INFLATION RATE ASSUMPTIONS

As at December 31, 2010

GLJ Forecast Prices and Costs

| Year | Oil | | Natural Gas | Edmonton Liquids Prices | | | Inflation Rate % | Exchange rate (US\$/Cdn) |
|---------------|------------------------|---|----------------------------|-------------------------|--------------------|---------------------------|------------------|--------------------------|
| | WTI Cushing (\$US/bbl) | Light, Sweet Crude Edmonton (\$Cdn/bbl) | AECO Gas Price (\$Cdn/Mcf) | Propane (\$Cdn/bbl) | Butane (\$Cdn/bbl) | Pentanes Plus (\$Cdn/bbl) | | |
| 2011 | 88.00 | 86.22 | 4.16 | 54.32 | 67.26 | 90.54 | 2.0 | 0.98 |
| 2012 | 89.00 | 89.29 | 4.74 | 56.25 | 68.75 | 91.96 | 2.0 | 0.98 |
| 2013 | 90.00 | 90.92 | 5.31 | 57.28 | 70.01 | 92.74 | 2.0 | 0.98 |
| 2014 | 92.00 | 92.96 | 5.77 | 58.56 | 71.58 | 94.82 | 2.0 | 0.98 |
| 2015 | 95.17 | 96.19 | 6.22 | 60.60 | 74.07 | 98.12 | 2.0 | 0.98 |
| 2016 | 97.55 | 98.62 | 6.53 | 62.13 | 75.94 | 100.59 | 2.0 | 0.98 |
| 2017 | 100.26 | 101.39 | 6.76 | 63.87 | 78.07 | 103.42 | 2.0 | 0.98 |
| 2018 | 102.74 | 103.92 | 6.90 | 65.47 | 80.02 | 106.00 | 2.0 | 0.98 |
| 2019 | 105.45 | 106.68 | 7.06 | 67.21 | 82.15 | 108.82 | 2.0 | 0.98 |
| 2020 | 107.56 | 108.84 | 7.21 | 68.57 | 83.80 | 111.01 | 2.0 | 0.98 |
| Thereafter 2% | | | | | | | | |

Total future development costs included in the reserves evaluation were \$137.0 million for total proved reserves and \$239.9 million for proved plus probable reserves. Further details related to future development costs, including assumptions regarding the timing of the expenditures, will be included in the Company's AIF for the 2010 fiscal year. Future development costs are associated with the reserves as disclosed in the GLJ report and do not necessarily represent the Company's current exploration and development budget.

CONTINUITY OF GROSS RESERVES

| | Natural Gas (Bcf) ⁽¹⁾ | | | Oil & Natural Gas Liquids (Mbbbls) | | |
|----------------------------------|----------------------------------|----------|--------|------------------------------------|----------|-------|
| | Proved | Probable | Total | Proved | Probable | Total |
| Opening balance | | | | | | |
| December 31, 2009 | 128.0 | 59.0 | 187.0 | 2,287 | 1,443 | 3,730 |
| Extensions and improved recovery | 7.6 | 9.0 | 16.6 | 1,766 | 1,432 | 3,198 |
| Technical revisions | 17.1 | (17.6) | (0.5) | 472 | (114) | 358 |
| Economic factors | (41.8) | 2.9 | (38.9) | (120) | (30) | (150) |
| Dispositions | - | - | - | (3) | (46) | (49) |
| Production | (13.6) | - | (13.6) | (503) | - | (503) |
| Closing balance | | | | | | |
| December 31, 2010 ⁽¹⁾ | 97.3 | 53.3 | 150.6 | 3,899 | 2,685 | 6,584 |

(1) The closing balance for natural gas includes 4.4 Bcf of proved and 3.9 Bcf of probable Coal Bed Methane reserves. The closing balance for oil and natural gas liquids includes 251 Mbbbls of proved and 140 Mbbbls of probable Heavy Oil reserves.

The Company's reserves life indices are 7.3 years total proved and 11.5 years proved plus probable, based on 2010 annual production. With the 25% reduction in GLJ's natural gas price outlook in the years 2011 to 2015, and 16% thereafter, the Company experienced a negative revision for economic factors of 7.1 MMBOE for total proved and 6.6 MMBOE for proved plus probable reserves. The economic factors negative revision was almost entirely related to the Company's undeveloped gas reserves in the Edmonton Sands. Offsetting the economic factors were positive technical revisions of 3.3 MMBOE total proved and 0.3 MMBOE proved plus probable reserves. In addition, the Company experienced positive proved developed producing additions and revisions of 2.2 MMBOE in the Edmonton Sands, indicative of improved performance. Reserves additions before revisions were 3.0 MMBOE total proved and 5.9 MMBOE proved plus probable, predominantly from Cardium oil horizontal drilling. The Company replaced 224% of its production with new proved plus probable reserves additions and technical revisions in 2010. The Company replaced 697% of its 2010 oil and NGL production with new P&P oil and NGL reserves.

FINDING, DEVELOPMENT AND ACQUISITION COSTS

Year Ended December 31, 2010

| (in thousands of dollars) | Proved | Proved plus Probable |
|---|------------|----------------------|
| Finding, development & acquisition expenditures | \$ 113,707 | \$ 113,707 |
| Change in future development costs | (60,613) | (20,200) |
| | \$ 53,094 | \$ 93,507 |
| Adjustment to change in future development costs for natural gas economic factors | 88,290 | 44,642 |
| | \$ 141,384 | \$ 138,149 |
| Reserve additions (MBOE) | 3,023 | 5,913 |
| Technical revisions (MBOE) | 3,318 | 269 |
| | 6,341 | 6,182 |
| Economic factors (MBOE) | (7,078) | (6,630) |
| | (737) | (448) |
| 2010 finding, development & acquisition costs – additions only, including change in future development costs (\$/BOE) | \$ 17.56 | \$ 15.81 |
| 2010 finding, development & acquisition costs – additions and technical revisions, including change in future development costs, excluding economic factors and the change in future development costs related to economic factors (\$/BOE) | \$ 22.30 | \$ 22.35 |

The Company's FD&A costs in 2010 were \$17.56 per BOE on a proved basis and \$15.81 per BOE on a proved plus probable basis for additions only, including changes in future development costs. The Company experienced a significant revision for economic factors in 2010 which not only reduced reserves but also reduced future development capital. To measure FD&A costs excluding the impact of economic factors, the future development capital was also adjusted upwards to exclude the effect of removing these reserves. FD&A costs including future development costs for additions and technical revisions, but excluding economic factors were \$22.30 per BOE total proved and \$22.35 per BOE for proved plus probable. FD&A costs are presented before economic factors as the amount would be negative or indeterminate after consideration of those revisions. Economic factors are influenced by consultant price forecasts and an uplift in natural gas price forecasts may cause economic factors to be positive in future years. Calculated on a similar basis, the Company's FD&A costs in 2009 were \$8.64 per BOE on a proved basis and \$8.46 per BOE on a proved plus probable basis and FD&A costs in 2008 were indeterminate. The three year average FD&A costs was also indeterminate as a result of the negative revisions in 2010 and 2008. There were no property acquisitions in the year and dispositions were negligible, so a separate calculation of finding and development costs excluding acquisitions has not been presented. The aggregate of the exploration, development and acquisition costs incurred in the most recent financial year and the change during the year in estimated future development costs generally will not reflect total finding, development and acquisition costs related to reserves additions for that year.

SHARE INFORMATION

The Company's shares have been listed on the Toronto Stock Exchange since September 7, 2005 under the symbol "AXL". As of March 25, 2011, there were 172.5 million common shares outstanding, 11.4 million stock options outstanding and \$50.0 million principal amount of convertible debentures which are convertible into common shares at a conversion price of \$1.55 per common share. During 2010, 84,900 common shares (2009 – Nil) were issued under the employee stock option plan.

SHARE PRICE ON TSX

| | 2010 | | 2009 | |
|--------------------------------------|------|-------------|------|-------------|
| High | \$ | 1.57 | \$ | 1.48 |
| Low | \$ | 0.95 | \$ | 0.65 |
| Close | \$ | 1.05 | \$ | 1.16 |
| Volume | | 120,489,236 | | 125,408,442 |
| Shares outstanding at December 31 | | 172,485,301 | | 150,500,401 |
| Market capitalization at December 31 | \$ | 181,109,566 | \$ | 174,580,465 |

The statistics above include trading on the Toronto Stock Exchange only. Shares also trade on alternative platforms like Alpha, Chi-X, Pure and Omega. Approximately 65.0 million common shares traded on these alternative exchanges in 2010. Including these exchanges, an average of 736,212 common shares traded per day in 2010 (2009 – 584,790), representing a turnover ratio of 109% (2009 – 117%).

In February 2010, the Company issued 21.9 million common shares at a price of \$1.45 per share pursuant to a short form prospectus.

RELATED PARTY TRANSACTIONS

On December 31, 2010, the Company issued 1,000 convertible debentures to directors at a price of \$1,000 per convertible debenture for total gross proceeds of \$1.0 million as part of a \$50.0 million bought share offering of convertible debentures.

In February 2010, the Company issued 352,466 common shares to directors at a price of \$1.45 per share for total gross proceeds of \$0.5 million as part of a \$31.8 million bought deal offering of common shares.

On May 28 2009, the Company issued 4,992,034 common shares to management and directors and 3,377,966 common shares to family of management and directors of the Company at a price of \$0.95 per share for total gross proceeds of \$8.0 million as part of a \$60.0 million bought deal offering of common shares.

LIQUIDITY AND CAPITAL RESOURCES

At December 31, 2010, the Company had outstanding bank loans of \$52.7 million, convertible debentures of \$50.0 million (principal) and a working capital deficiency of \$18.8 million, excluding the unrealized loss on derivative contracts and future income tax assets. The working capital deficiency is due to accruals associated with the capital program in the last quarter of the year.

The Company's current capital budget for 2011 is \$75 million, which is almost entirely directed at oil horizontal drilling, primarily in the Cardium. The Company is committed to drill 74 gross Edmonton Sands gas wells under its farm-in agreement by March 31, 2012. The Company does not plan to drill any additional Edmonton Sands gas wells until the first quarter of 2012. The Company plans to drill 15 gross (11.3 net revenue) Cardium oil wells in the first quarter of 2011.

The Company's need for capital will be both short-term and long-term in nature. Short-term capital is required to finance accounts receivable and other similar short-term assets while the acquisition and development of oil and natural gas properties requires larger amounts of long-term capital. At December 31, 2010, the Company had total credit facilities of \$125 million, consisting of an \$80 million extendible revolving term credit facility, a \$10 million working capital credit facility and a \$35 million supplemental credit facility with a syndicate of Canadian banks. The Company had \$72.2 million of credit available at December 31, 2010. Draws over \$30 million under the supplemental facility will be subject to the consent of the syndicate at the time of the drawdown. On December 31, 2010, the Company completed a convertible subordinated debenture financing for proceeds, net of commission and expenses, of \$47.7 million. The net proceeds were initially used to pay down bank debt. Anderson Energy will prudently use its bank loan facilities to finance its operations as required. The available lending limits under the bank facilities are reviewed twice a year and are based on the bank syndicate's interpretation of the Company's reserves and future commodity prices. The last review was conducted in November 2010. There can be no assurance that the amount of the available bank lines will not be adjusted at the next scheduled review to be completed prior to July 12, 2011. The Company will continue to fund its ongoing operations from a combination of cash flow, debt, asset dispositions and equity financing as needed.

CONTRACTUAL OBLIGATIONS

The Company enters into various contractual obligations in the course of conducting its operations. These obligations include:

- *Loan agreements* – The reserves-based extendible, revolving term credit facility and working capital credit facility have a revolving period ending on July 12, 2011, extendible at the option of the lenders. If not extended, the facilities cease to revolve and all outstanding advances thereunder become repayable one year from the term date of July 12, 2011. The supplemental facility is available on a revolving basis and expires on July 1, 2011 with any amounts outstanding due in full at that time. No amounts were drawn under the supplemental facility at December 31, 2010.
- *Convertible debentures* – The Company issued \$50.0 million in convertible debentures on December 31, 2010. The convertible debentures have a face value of \$1,000, bear

interest at the rate of 7.5% per annum payable semi-annually in arrears on the last day of January and July of each year, commencing on July 31, 2011 and mature on January 31, 2016. The convertible debentures are convertible at the holder's option at a conversion price of \$1.55 per common share, subject to adjustment in certain events. The Debentures are not redeemable by the Corporation before January 31, 2014.

- *Lease for office space* – This lease expires on November 30, 2012. Future minimum lease payments are expected to be \$1.8 million per year in 2011, and \$1.6 million in 2012.
- *Firm service transportation commitments* – The Company has entered into firm service transportation agreements for approximately 29 million cubic feet per day of gas sales for various terms expiring between 2011 and 2020. Based on rate schedules announced to date, the payments in each of the next five years and thereafter are estimated to be \$1.6 million in 2011, \$1.3 million in 2012, \$0.8 million in 2013, \$0.7 million in 2014, \$0.6 million in 2015 and \$0.4 million thereafter.
- *Oil transportation contract* – In 2010, the Company entered into a facilities construction and operation agreement pursuant to which it is committed to ship a minimum volume of gross crude oil through new facilities and pipelines being constructed in Garrington. The total financial commitment is \$2.6 million to be incurred over a minimum of five years. The contract contains a minimum volume requirement per year for the first five years following completion of construction which is expected to be in the second quarter of 2011. In the event that the volume shipped is less than the minimum volume, the Company will be subject to a fee per cubic metre of oil on the difference between actual volumes shipped and the minimum volume required. Conversely, if the Company exceeds the minimum volume requirement in a single year, the excess is carried forward as a credit to the minimum volume requirement in the subsequent year. If no volumes were shipped, a minimum of \$0.26 million would be payable each year. After the total contracted volumes have been shipped, the contract will automatically renew for one year periods unless terminated.
- *Farm-in* – On January 30, 2009, the Company announced a farm-in agreement with a large international oil and gas company on lands near its existing core operations. Under the farm-in agreement, the Company has access to 388 gross (205 net) sections of land. During the commitment phase of the transaction, the Company is committed to drill, complete and equip 200 wells to earn an interest in up to 120 sections. The Company has drilled 126 wells under the commitment to December 31, 2010. The Company is obligated to complete the drilling of the remaining wells on or before March 31, 2012. The commitment is subject to certain guarantees. The Company estimates that its minimum commitment to drill the remaining 74 wells is \$10 million. The Company currently plans to defer its spending on the farm-in project until the first quarter of 2012.

CRITICAL ACCOUNTING ESTIMATES

The Company's significant accounting policies are disclosed in note 1 to the consolidated financial statements. Certain accounting policies require that management make appropriate decisions with respect to the formulation of estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses. These accounting policies are discussed below and are included to aid the reader in assessing the critical accounting policies and practices of the Company and the likelihood of materially different results than reported. The Company's management reviews its estimates regularly. The emergence of new information and changed circumstances may result in actual results that differ materially from current estimates.

Proved Oil and Gas Reserves. Proved oil and gas reserves, as defined by the Canadian Securities Administrators in NI 51-101 with reference to the Canadian Oil and Gas Evaluation Handbook, are those reserves that can be estimated with a high degree of certainty to be

recoverable. Determination of reserves is a complex process involving judgments, estimates and decisions based on available geological, engineering, production and any other relevant data. These estimates are subject to material change as economic conditions change and ongoing production and development activities provide new information.

Independent reserves evaluators have prepared the Company's oil and gas reserves estimate. Estimates are reviewed and revised as appropriate. Revisions occur as a result of changes in prices, costs, fiscal regimes, reservoir performance, methodology of booking undeveloped reserves, or a change in the Company's development plans. The effect of changes in proved oil and gas reserves on the financial results and financial position of the Company is described below under the heading "Full Cost Accounting" and "Full Cost Accounting Ceiling Test".

Full Cost Accounting. The Company follows the full cost method of accounting for petroleum and natural gas properties, whereby all costs of exploring for and developing petroleum and natural gas properties and related reserves are capitalized. The capitalized costs are depleted and depreciated using the unit-of-production method based on estimated proved reserves. Reserves estimates can have a significant impact on earnings, as they are a key component in the calculation of depletion and depreciation. Downward revisions in reserves estimates or upward revisions in future development cost estimates could result in a higher depletion and depreciation charge to earnings. In addition, if net capitalized costs are determined to be in excess of the calculated ceiling, which is based largely on reserves estimates (see "Full Cost Accounting Ceiling Test"), the excess must be written off as an expense charged against earnings. In the event of property dispositions, proceeds are normally deducted from the full cost pool without recognition of gain or loss unless there is a change in the depletion rate of 20% or greater.

Unproved Properties. Certain costs related to unproved properties are excluded from costs subject to depletion until proved reserves have been determined or their value is impaired. These properties are reviewed quarterly and any impairment is transferred to the costs being depleted. The costs relating to unproved properties are also excluded from the book value subject to the ceiling test measurement.

Full Cost Accounting Ceiling Test. Petroleum and natural gas assets are evaluated in each reporting period to determine that the carrying amount in a cost centre is recoverable and does not exceed the fair value of the properties in the cost centre.

Impairment is indicated if the carrying value of the oil and gas cost centre is not recoverable by the future undiscounted cash flows. If impairment is indicated, the amount by which the carrying value exceeds the estimated fair value of the oil and gas assets is charged to earnings. The ceiling test is based on estimates of reserves, production rates, petroleum and natural gas prices, future costs and other relevant assumptions. By their nature, these estimates are subject to measurement uncertainty and the impact on the financial statements could be material.

Asset Retirement Obligations. The Company is required to provide for future removal and site restoration costs. The Company must estimate these costs in accordance with existing laws, contracts or other policies. These estimated costs are charged to property, plant & equipment and the appropriate liability account over the expected service life of the asset. The estimate of future removal and site restoration costs involves a number of estimates related to timing of abandonment, determination of the economic life of the asset, costs associated with abandonment and site restoration, review of potential abandonment methods and salvage/usage of tangible equipment.

Income Taxes. The determination of the Company's income and other tax liabilities requires interpretation of complex laws and regulations often involving multiple jurisdictions. All tax filings are subject to audit and potential reassessment after the lapse of considerable time.

Accordingly, the actual income tax liability may differ from that estimated and recorded by management. The Company estimates its future income tax rate in calculating its future income tax liability. Various assumptions are made in assessing when temporary differences will reverse and this will impact the rate used.

Stock-Based Compensation. In order to recognize stock-based compensation costs, the Company estimates the fair value of stock options granted using assumptions related to interest rates, expected life of the option, forfeitures, volatility of the underlying security and expected dividend yields. These assumptions may vary over time.

INTERNATIONAL FINANCIAL REPORTING STANDARDS (“IFRS”)

In October 2009, the Accounting Standards Board issued a third and final IFRS Omnibus Exposure Draft confirming that publicly accountable enterprises will be required to apply IFRS, in full and without modification, for all financial periods beginning January 1, 2011. The adoption date of January 1, 2011 requires the restatement, for comparative purposes, of amounts reported by the Company for the year ended December 31, 2010, including the opening balance sheet as at January 1, 2010.

In response, the Company has completed its high-level IFRS changeover plan and established a timeline for the execution and completion of the conversion project. The changeover plan was determined following a preliminary assessment of the differences between Canadian GAAP and IFRS and the potential effects of IFRS to accounting and reporting processes, information systems, business processes and external disclosures. This assessment has provided insight into what are anticipated to be the most significant areas of difference applicable to the Company.

The Company has performed an in-depth review of the significant areas of difference identified during the preliminary assessment, in order to identify all specific Canadian GAAP and IFRS differences and select ongoing IFRS policies. Key areas addressed were also reviewed to determine any information technology issues, the impact on internal controls over financial reporting and the impact on business activities including the effect, if any, on covenants and compensation arrangements. External advisors have been retained to assist management with the project on an as needed basis to ensure IFRS readiness for the filing of the Company’s first quarterly IFRS financial statements of 2011.

The Audit Committee has approved the IFRS accounting policy selections presented by management to date and disclosed herein. Below is a summary of the Company’s accounting policies that are expected to have a significant impact on the Company’s consolidated financial statements. The list and comments below should not be regarded as a complete list of changes that will result from the transition to IFRS. The amounts quantified are based on the Company’s internal calculations and have not been audited by the Company’s external auditors.

Note that most adjustments required on transition to IFRS will be made retrospectively, against opening retained earnings in the first comparative balance sheet. Transitional adjustments relating to those standards where comparative figures are not required to be restated because they are applied prospectively will only be made as of the first day of the year of transition.

IFRS 1 “First-Time Adoption of International Financial Reporting Standards” provides entities adopting IFRS for the first time with a number of optional exemptions and mandatory exceptions, in certain areas, to the general requirement for full retrospective application of IFRS. The Company has finalized the various accounting policy choices available with the significant IFRS 1 exemptions taken described below.

Property, Plant and Equipment. International Accounting Standard (IAS) 16 "Property, Plant & Equipment" and Canadian GAAP contain the same basic principles, however there are some differences. IFRS requires that significant parts of an asset be depreciated separately and depreciation commences when the asset is available for use. There will be more depreciable components than the current single full cost pool as depletion and depreciation cannot be calculated at a level more aggregated than a cash generating unit. At transition, the Company did not identify any significant components that needed to be depreciated on a basis other than unit-of-production.

IFRS also permits property, plant equipment to be measured using the fair value model or the historical cost model. The Company is not planning on adopting the fair value measurement model for property, plant and equipment.

IFRS 1 contains an exemption where by a company may apply IFRS prospectively by utilizing its current reserves (volumes or values) at the transition date to allocate the Company's full cost pool, with the provision that an impairment test, under IFRS standards, be conducted at the transition date. The Company intends to use this exemption and allocate the net book values based on reserve volumes.

The Company has the option to calculate depletion using a reserve base of proved reserves or both proved plus probable reserves, as compared to the Canadian GAAP method of calculating depletion using proved reserves only. The Company plans to deplete its property, plant and equipment using proved plus probable reserves. As a result of this policy choice, the Company expects that its quarterly depletion under IFRS will be lower than it was under Canadian GAAP.

Provisions. Under IFRS, similar to Canadian GAAP, the Company is required to record obligations relating to the retirement of its wells and facilities where a legal or contractual obligation currently exists. Upon the adoption of IFRS, the Company will also need to evaluate if there are any constructive obligations where the decommissioning liability would also need to be recognized. Currently, the Company has not identified any constructive obligations.

The Company intends to apply the IFRS 1 exemption whereby the decommissioning liability provision is recalculated at January 1, 2010 using the IFRS methodology and any adjustments would be offset against opening retained earnings. As a result of applying this IFRS 1 exemption, at transition, the Company expects to increase its provision by \$12 to \$15 million. The increase in the provision is a result of the Company applying a risk free rate to the future cash flows. The use of a risk free rate will result in lower accretion expense, which is included in finance expenses, and higher depletion expense subsequent to transition.

Impairment of Assets. IAS 36 "Impairment of Assets" requires that impairments be determined based on discounted cash flows. This differs from the current two step practice where the asset's carrying value is initially compared to the estimated undiscounted future cash flows, and only if the carrying value exceeds the undiscounted future cash flows is a discounted analysis, step two, required. There is no undiscounted test under IFRS. This may result in more frequent write-downs upon transition.

In addition, under IFRS, an entity must also evaluate whether there are changes in circumstances that would support an impairment reversal, which is not allowable under GAAP.

Another difference arises in the level at which an impairment test is performed. Under IFRS, impairment testing will be performed on cash generating units. The Company has identified its cash generating units based on the reserve characteristics. At transition, the Company has four cash generating units: Horizontal Oil, Deep Gas, Shallow Gas and Non-Core.

As a result of applying the IFRS 1 exemption for deemed cost, the Company tested for impairment at transition. Based on preliminary calculations, the Company expects an impairment at transition on January 1, 2010 of between \$50 and \$70 million with the offset going to opening retained earnings. Throughout 2010, the estimates of forward natural gas prices declined significantly (GLJ price forecasts declined 25% on average for 2011 to 2015, and 16% thereafter) and year end reserves were subject to a 6.6 MMBOE reduction for economic factors. As a result, the Company expects to record additional significant impairments in the natural gas weighted cash generating units for 2010.

Income taxes. Under IAS 12 "Income Taxes", current and deferred tax are normally recognized in the income statement, except to the extent that tax arises from (1) an item that has been recognized directly in equity, whether in the same or a different period, (2) a business combination or (3) a share based payment transaction. If a deferred tax asset or liability is re-measured subsequent to initial recognition, the impact of re-measurement is recorded in earnings, unless it relates to an item originally recognized in equity, in which case the change would also be recorded in equity. The practice of tracking the re-measurement of taxes back to the item which originally triggered the recognition is commonly referred to as "backwards tracing." Canadian GAAP prohibits backwards tracing except on business combinations and financial reorganizations. As a result of the changes to the Company's transition balance sheet described herein, the Company estimates that its deferred tax liability will be reduced by \$18 to \$22 million with the offset going to opening retained earnings.

Share based payments. Under IFRS 2 "Share-Based Payments", graded vested options are required to be separated into their vesting tranches and valued and accounted for separately. This differs from Canadian GAAP, where graded vested options are valued at grant date and expensed using the straight line method. IFRS 1 provides an exemption on IFRS 2 for equity instruments which vested before the transition date and does not require them to be retroactively restated. All unvested options at transition date will be required to be retroactively restated with the adjustment going through opening retained earnings on transition. The Company intends to use this exemption and expects the transition impact to be less than \$0.5 million.

In addition to accounting policy differences discussed above, the Company's transition to IFRS is expected to impact its internal controls over financial reporting, disclosure controls and procedures, certain business activities and IT systems.

Internal controls over financial reporting ("ICFR"). The Company is currently in the process of reviewing its ICFR documentation and is identifying instances where controls must be amended or added in order to address the accounting policy changes required under IFRS. No material changes in control procedures are expected as a result of transition to IFRS.

Disclosure controls and procedures. The Company is currently assessing the impact of transition to IFRS on its disclosure controls and procedures and does not expect any material changes required in its control environment. It is expected that there will be increased note disclosure around certain financial statement items than what is currently required under Canadian GAAP. Management is currently drafting its IFRS note disclosure in accordance with current IFRS standards and continues to monitor requirements put forth by the International Accounting Standards Board ("IASB") in discussion papers and exposure drafts for future disclosure requirements. Throughout the transition process, the Company has carefully considered its stakeholders' information requirements and will continue to ensure that adequate and timely information is provided to meet these needs.

Business activities. Management has been cognizant of the upcoming transition to IFRS, and as such, has worked with its counterparties and lenders to ensure that any agreements that contain references to Canadian GAAP financial statements are modified to allow for IFRS statements. Based on the changes to the Company's accounting policies, no issues are expected to arise with the existing wording of credit facilities and related agreements as a result of the conversion to IFRS.

IT systems. The Company has recently completed the accounting system upgrades required in order to prepare for IFRS reporting. The modifications were not significant, however, they were deemed critical in order to allow for reporting of both Canadian GAAP and IFRS statements in 2010 as well as the modifications required to track property, plant and equipment at a more granular level of detail for IFRS reporting.

Throughout the first half of 2011, the Company will continue calculating the quarterly impact of its policy choices under IFRS. The Company's external auditors have been engaged to review the 2010 adjustments in early April 2011 in order to have sufficient time to review the Company's information for its first IFRS financial statements.

The Company continues to monitor standards development as issued by the IASB and the AcSB as well as regulatory developments as issued by the Canadian Securities Administrators, which may affect the timing, nature or disclosure of its adoption of IFRS.

CONTROLS AND PROCEDURES

The Chief Executive Officer and the Chief Financial Officer have evaluated and tested the effectiveness of Anderson Energy's disclosure controls and procedures as of December 31, 2010 and have concluded that such disclosure controls and procedures were effective.

The Chief Executive Officer and the Chief Financial Officer have evaluated and tested the design and operating effectiveness of Anderson Energy's internal controls over financial reporting as of December 31, 2010 and have concluded that, these internal controls are designed properly and are effective in the preparation of financial statements for external purposes in accordance with Canadian GAAP. There were no material changes in the Company's internal controls over financial reporting in the last quarter of the Company's fiscal year.

Because of inherent limitations, internal controls over financial reporting may not prevent or detect all misstatements, errors or fraud. Control systems, no matter how well designed, only provide reasonable, not absolute, assurance that the objectives of the controls systems are met.

BUSINESS RISKS

Oil and gas exploration and production is capital intensive and involves a number of business risks including, without limitation, the uncertainty of finding new reserves, the instability of commodity prices, weather and various operational risks. Commodity prices are influenced by local and worldwide supply and demand, OPEC actions, ongoing global economic concerns, the U.S. dollar exchange rate, transportation costs, political stability and seasonal and weather related changes to demand. The price of natural gas has weakened due to increasing U.S. gas production driven primarily by the U.S. shale gas plays. The large amount of gas in storage combined with strong U.S. gas production and financial market fears has continued to suppress the price of natural gas. Oil prices have increased recently as crude oil is a geopolitical commodity, and is responding to instability in the Middle East. The industry is subject to extensive governmental regulation with respect to the environment. Operational risks include well performance, uncertainties inherent in estimating reserves, timing of/ability to obtain drilling licences and other regulatory approvals, ability to obtain equipment, expiration of licences and leases, competition from other producers, sufficiency of insurance, ability to manage growth,

reliance on key personnel, third party credit risk and appropriateness of accounting estimates. These risks are described in more detail in the Company's Annual Information Form for the year ended December 31, 2010 to be filed with Canadian securities regulatory authorities on SEDAR.

The Company anticipates making substantial capital expenditures for the acquisition, exploration, development and production of oil and natural gas reserves in the future. As the Company's revenues may decline as a result of decreased commodity pricing, it may be required to reduce capital expenditures. In addition, uncertain levels of near term industry activity coupled with the present global economic concerns exposes the Company to additional access to capital risk. There can be no assurance that debt or equity financing, or funds generated by operations will be available or sufficient to meet these requirements or for other corporate purposes or, if debt or equity financing is available, that it will be on terms acceptable to the Company. The inability of the Company to access sufficient capital for its operations could have a material adverse effect on the Company's business, financial condition, results of operations and prospects.

Anderson Energy manages these risks by employing competent professional staff, following sound operating practices and using capital prudently. The Company generates its exploration prospects internally and performs extensive geological, geophysical, engineering, and environmental analysis before committing to the drilling of new prospects. Anderson Energy seeks out and employs new technologies where possible. With the Company's extensive drilling inventory and advance planning, the Company can manage the slower pace of regulatory approvals and the requirements for extensive landowner consultation.

The Company has a formal emergency response plan which details the procedures employees and contractors will follow in the event of an operational emergency. The emergency response plan is designed to respond to emergencies in an organized and timely manner so that the safety of employees, contractors, residents in the vicinity of field operations, the general public and the environment are protected. A corporate safety program covers hazard identification and control on the jobsite, establishes Company policies, rules and work procedures and outlines training requirements for employees and contract personnel.

The Company currently deals with a small number of buyers and sales contracts, and endeavors to ensure that those buyers are an appropriate credit risk. The Company continuously evaluates the merits of entering into fixed price or financial hedge contracts for price management.

The oil and natural gas business is subject to regulation and intervention by governments in such matters as the awarding of exploration and production interests, the imposition of specific drilling obligations, environmental protection controls, control over the development and abandonment of fields (including restrictions on production) and possibly expropriation or cancellation of contract rights. As well, governments may regulate or intervene with respect to prices, taxes, royalties and the exportation of oil and natural gas. Such regulation may be changed from time to time in response to economic or political conditions. The implementation of new regulations or the modification of existing regulations affecting the oil and natural gas industry could reduce demand for oil and natural gas, increase the Company's costs or affect its future opportunities.

The oil and natural gas industry is currently subject to environmental regulations pursuant to a variety of provincial and federal legislation. Such legislation provides for restrictions and prohibitions on the release or emission of various substances produced in association with certain oil and gas industry operations. Such legislation may also impose restrictions and prohibitions on water use or processing in connection with certain oil and gas operations. In addition, such legislation requires that well and facility sites be abandoned and reclaimed to the satisfaction of provincial authorities. Compliance with such legislation can require significant

expenditures and a breach of such requirements may result, amongst other things in suspension or revocation of necessary licenses and authorizations, civil liability for pollution damage, and the imposition of material fines and penalties.

Canada is a signatory to the United Nations Framework Convention on Climate Change. The Canadian federal government previously released the Regulatory Framework for Air Emissions, updated March 10, 2008 by Turning the Corner: Regulatory Framework for Industrial Greenhouse Gas Emissions (collectively, the "Regulatory Framework"), for regulating greenhouse gas ("GHG") emissions by proposing mandatory emissions intensity reduction obligations on a sector by sector basis. Legislation to implement the Regulatory Framework had been expected to be put in place this year, but the federal government has delayed the release of any such legislation and potential federal requirements in respect of GHG emissions are unclear. On January 30, 2010, the Canadian federal government announced its new target to reduce overall Canadian GHG emissions by 17% below 2005 levels by 2020, from the previous target of 20% from 2006 levels by 2020, to align itself with the GHG emission reduction goals of the United States. In 2009, the Canadian federal government announced its commitment to work with the provincial governments to implement a North American-wide cap and trade system for GHG emissions, in cooperation with the United States. Canada would have its own cap-and-trade market for Canadian-specific industrial sectors that could be integrated into a North American market for carbon permits. Additionally, regulation can take place at the provincial and municipal level. For example, Alberta introduced the Climate Change and Emissions Management Act, which provides a framework for managing GHG emissions and establishes a target of reducing specified gas emissions relative to gross domestic product to an amount that is equal to or less than 50% of 1990 levels by December 31, 2020. The accompanying regulations, the Specified Gas Emitters Regulation and the Specified Gas Emitters Reporting Regulation require mandatory emissions reductions through the use of emissions intensity targets and impose duties to report. The Canadian federal government proposes to enter into equivalency agreements with provinces that establish a regulatory regime to ensure consistency with the federal plan, but the success of any such plan is doubtful in the current political climate, leaving multiple overlapping levels of regulation.

The Government of Alberta implemented a new oil and gas royalty framework effective January 2009. The new framework establishes new royalties for conventional oil, natural gas and bitumen that are linked to price and production levels and apply to both new and existing conventional oil and gas activities and oil sands projects. Under the framework, the formula for conventional oil and natural gas royalties uses a sliding rate formula, dependent on the market price and production volumes. Royalty rates for conventional oil range from 0% to 50%. Natural gas royalty rates range from 5% to 50%.

In November 2008, the Government of Alberta announced that companies drilling new natural gas and conventional oil wells at depths between 1,000 and 3,500 metres, which are spudded between November 19, 2008 and December 31, 2013, will have a one-time option of selecting new transitional royalty rates or the new royalty framework rates. The transition option provides lower royalties in the initial years of a well's life. For example, under the transition option, royalty rates for natural gas wells will range from 5% to 30%. The option for producers to elect transitional royalties in respect of qualifying deep wells ended on December 31, 2010 and any wells spudded on or after January 1, 2011 are subject to the royalty rates discussed below. Wells that are subject to transitional royalty rates will automatically revert to the new royalty framework rates on January 1, 2014.

On March 3, 2009, the Government of Alberta announced a three-point incentive program. Amendments to the program were announced on June 11 and June 25, 2009. This incentive program includes a drilling credit for new oil and natural gas wells drilled between April 1, 2009 and March 31, 2011, providing a \$200 per metre drilled royalty credit to companies. The credit can be used to offset up to 50% of Crown royalties payable after the wells have been drilled up until March 31, 2011. There is also a new well incentive program that provides a maximum 5% royalty rate for the first 12 months of production from new wells that begin producing oil or natural gas between April 1, 2009 and March 31, 2011 to a maximum of 50,000 barrels of oil or 500 million cubic feet of natural gas. The province of Alberta will also invest \$30 million in a fund committed to abandonment and reclamation projects where there is no legally responsible or financially able party to deal with the clean-up of inactive wells.

On March 11, 2010, the Alberta government announced its intention to adjust royalty rates effective January 1, 2011. This adjustment includes making the incentive program royalty rate of 5% on new natural gas and conventional oil wells a permanent feature of the royalty system with the time and volume limits discussed above. The maximum royalty rate was reduced from the current level of 50% to 40% for conventional oil and to 36% for natural gas. The transitional royalty framework for oil and gas will continue until December 31, 2013 as announced but no new wells will be allowed to select transitional royalty rates effective January 1, 2011; wells that have selected the transitional royalty rates will be allowed to switch to the new rates effective January 1, 2011. Royalty curves incorporating the changes announced on March 11, 2010 were released on May 27, 2010.

The changes to the royalty regime in the Province of Alberta are subject to certain risks and uncertainties. There may be modifications introduced to the royalty structure and such changes may be adverse to the business of the Company. There can be no assurance that the Government of Alberta or the Government of Canada will not adopt new royalty regimes which may render the Company's projects uneconomic or otherwise adversely affect the business of the Company.

BUSINESS PROSPECTS

The Company believes it has an excellent future drilling inventory in the Cardium light oil horizontal oil play and is focused on growing its production and reserves with Cardium horizontal drilling. The Company has 112.5 gross (65.8 net) sections in the fairway. At a drilling density of three wells per section, the potential drilling inventory is 338 gross (197.4 net) Cardium horizontal locations. The Company continues to add to its land position and drilling inventory through a combination of acquisitions, property swaps and farm-ins, and continues to implement new technologies to control and reduce its costs in this project.

The Company's annual production guidance for 2011 is 7,500 BOED. Risks associated with this guidance include continued low commodity prices which may restrict capital spending, new well performance, gas plant capacity, gas plant turnaround duration, regulatory issues, weather problems and access to industry services.

QUARTERLY INFORMATION

The following table provides financial and operating results for the last eight quarters. Commodity prices have declined from the first quarter of 2009 and remain volatile, affecting funds from operations and earnings throughout 2009 and 2010.

SELECTED QUARTERLY INFORMATION

(\$ amounts in thousands, except per share amounts and prices)

| | <u>Q4 2010</u> | <u>Q3 2010</u> | <u>Q2 2010</u> | <u>Q1 2010</u> |
|---|-----------------------|-----------------------|-----------------------|-----------------------|
| Oil and gas revenue before royalties ⁽¹⁾ | \$ 23,946 | \$ 18,928 | \$ 20,318 | \$ 23,265 |
| Funds from operations | \$ 9,515 | \$ 8,026 | \$ 9,004 | \$ 10,635 |
| Funds from operations per share | | | | |
| Basic | \$ 0.06 | \$ 0.05 | \$ 0.05 | \$ 0.06 |
| Diluted | \$ 0.06 | \$ 0.05 | \$ 0.05 | \$ 0.06 |
| Net loss | \$ (11,741) | \$ (9,046) | \$ (8,891) | \$ (5,953) |
| Net loss per share | | | | |
| Basic | \$ (0.07) | \$ (0.05) | \$ (0.05) | \$ (0.04) |
| Diluted | \$ (0.07) | \$ (0.05) | \$ (0.05) | \$ (0.04) |
| Capital expenditures, including acquisitions, net of dispositions | \$ 26,473 | \$ 39,528 | \$ 12,745 | \$ 33,427 |
| Cash from operating activities | \$ 10,721 | \$ 8,437 | \$ 8,892 | \$ 12,946 |
| Daily sales | | | | |
| Natural gas (Mcf) | 38,479 | 35,778 | 38,998 | 35,221 |
| Liquids (bpd) | 1,815 | 1,329 | 1,232 | 1,130 |
| BOE (BOED) | 8,228 | 7,292 | 7,732 | 7,000 |
| Average prices | | | | |
| Natural gas (\$/Mcf) | \$ 3.48 | \$ 3.43 | \$ 3.78 | \$ 5.22 |
| Liquids (\$/bbl) | \$ 69.11 | \$ 58.61 | \$ 60.28 | \$ 62.43 |
| BOE (\$/BOE) ⁽¹⁾ | \$ 31.63 | \$ 28.21 | \$ 28.88 | \$ 36.93 |

| | <u>Q4 2009</u> | <u>Q3 2009</u> | <u>Q2 2009</u> | <u>Q1 2009</u> |
|--|-----------------------|-----------------------|-----------------------|-----------------------|
| Oil and gas revenue before royalties ⁽¹⁾ | \$ 20,439 | \$ 14,617 | \$ 17,508 | \$ 24,429 |
| Funds from operations | \$ 9,151 | \$ 6,623 | \$ 6,692 | \$ 8,792 |
| Funds from operations per share | | | | |
| Basic | \$ 0.06 | \$ 0.04 | \$ 0.06 | \$ 0.10 |
| Diluted | \$ 0.06 | \$ 0.04 | \$ 0.06 | \$ 0.10 |
| Net loss | \$ (6,457) | \$ (9,432) | \$ (10,410) | \$ (10,159) |
| Net loss per share | | | | |
| Basic | \$ (0.04) | \$ (0.06) | \$ (0.09) | \$ (0.12) |
| Diluted | \$ (0.04) | \$ (0.06) | \$ (0.09) | \$ (0.12) |
| Capital expenditures, including acquisitions net of dispositions | \$ 11,312 | \$ 6,571 | \$ 2,130 | \$ 13,545 |
| Cash from operating activities | \$ 5,361 | \$ 6,689 | \$ 2,472 | \$ 9,298 |
| Daily sales | | | | |
| Natural gas (Mcf) | 34,938 | 36,282 | 40,495 | 42,344 |
| Liquids (bpd) | 1,257 | 1,013 | 1,040 | 1,448 |
| BOE (BOED) | 7,080 | 7,060 | 7,789 | 8,505 |
| Average prices | | | | |
| Natural gas (\$/Mcf) | \$ 4.28 | \$ 2.81 | \$ 3.43 | \$ 5.15 |
| Liquids (\$/bbl) | \$ 53.79 | \$ 53.84 | \$ 49.00 | \$ 38.69 |
| BOE (\$/BOE) ⁽¹⁾ | \$ 31.38 | \$ 22.50 | \$ 24.70 | \$ 31.91 |

(1) Includes royalty and other income classified with oil and gas sales and excludes the realized and unrealized losses on derivative contracts in the fourth quarter of 2010 of \$0.1 million and \$1.9 million respectively.

SELECTED ANNUAL INFORMATION

YEARS ENDED DECEMBER 31

(in thousands, except per share amounts)

| | 2010 | 2009 | 2008 |
|---|-------------|-------------|-------------|
| Total oil and gas revenues ⁽¹⁾ | \$ 86,457 | \$ 76,993 | \$ 156,245 |
| Total oil and gas revenues, net of royalties ⁽¹⁾ | \$ 77,446 | \$ 68,740 | \$ 122,207 |
| Earnings (loss) before goodwill impairment | \$ (35,631) | \$ (36,458) | \$ 8,500 |
| Earnings (loss) before goodwill impairment per share | | | |
| Basic | \$ (0.21) | \$ (0.29) | \$ 0.10 |
| Diluted | \$ (0.21) | \$ (0.29) | \$ 0.10 |
| Net loss | \$ (35,631) | \$ (36,458) | \$ (26,864) |
| Net loss per share | | | |
| Basic | \$ (0.21) | \$ (0.29) | \$ (0.31) |
| Diluted | \$ (0.21) | \$ (0.29) | \$ (0.31) |
| Total assets | \$ 535,115 | \$ 497,169 | \$ 543,533 |
| Total bank loans | \$ 52,719 | \$ 62,404 | \$ 85,314 |
| Total convertible debentures, liability component | \$ 43,460 | \$ - | \$ - |

(1) Includes royalty and other income classified with oil and gas sales. Excludes the realized and unrealized losses on derivative contracts in 2010 of \$0.1 million and \$1.9 million respectively.

ADVISORY

Certain information regarding Anderson Energy Ltd. in this news release including, without limitation, management's assessment of future plans and operations, benefits and valuation of the development prospects described herein, number of locations in drilling inventory and wells to be drilled, timing and location of drilling and tie-in of wells and the costs thereof, productive capacity of the wells, timing of and construction of facilities, expected production rates, dates of commencement of production, amount of capital expenditures and timing thereof, value of undeveloped land, extent of reserves additions, ability to attain cost savings, drilling program success, impact of changes in commodity prices on operating results, impact of changes to the royalty regime applicable to the Company, including payment of drilling incentive credits, commodity price outlook and general economic outlook may constitute forward-looking statements under applicable securities laws and necessarily involve risks and assumptions made by management of the Company including, without limitation, risks associated with oil and gas exploration, development, exploitation, production, marketing and transportation, loss of markets, volatility of commodity prices, currency fluctuations, imprecision of reserves estimates, environmental risks, competition from other producers, inability to retain drilling rigs and other services, capital expenditure costs, including drilling, completion and facilities costs, unexpected decline rates in wells, wells not performing as expected, incorrect assessment of the value of acquisitions and farm-ins, failure to realize the anticipated benefits of acquisitions and farm-ins, delays resulting from or inability to obtain required regulatory approvals, changes to government regulation and ability to access sufficient capital from internal and external sources. As a consequence, actual results may differ materially from those anticipated in the forward-looking statements. Readers are cautioned that the foregoing list of factors is not exhaustive. Additional information on these and other factors that could affect Anderson Energy's operations and financial results are included in reports on file with Canadian securities regulatory authorities and may be accessed through the SEDAR website (www.sedar.com) and at Anderson Energy's website (www.andersonenergy.ca).

Furthermore, the forward-looking statements contained in this news release are made as at the date of this news release and Anderson Energy does not undertake any obligation to update publicly or to revise any of the included forward-looking statements, whether as a result of new information, future events or otherwise, except as may be required by applicable securities laws.

Disclosure provided herein in respect of barrels of oil equivalent (BOE) 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.

ANDERSON ENERGY LTD.

Consolidated Balance Sheets

DECEMBER 31, 2010 AND 2009

(Stated in thousands of dollars)
(Unaudited)

2010

2009

ASSETS

Current assets:

| | | | | |
|--|----|----------------|----|----------------|
| Cash and cash equivalents | \$ | 4,024 | \$ | 1 |
| Accounts receivable and accruals (note 11) | | 20,998 | | 22,990 |
| Prepaid expenses and deposits | | 3,052 | | 3,778 |
| Future income tax asset (note 7) | | <u>508</u> | | <u>-</u> |
| | | 28,582 | | 26,769 |
| Property, plant and equipment (note 3) | | <u>506,533</u> | | <u>470,400</u> |
| | \$ | <u>535,115</u> | \$ | <u>497,169</u> |

LIABILITIES AND SHAREHOLDERS' EQUITY

Current liabilities:

| | | | | |
|---|----|------------------|----|-----------------|
| Accounts payable and accruals | \$ | 46,862 | \$ | 36,889 |
| Unrealized loss on derivative contracts (note 11) | | <u>1,918</u> | | <u>-</u> |
| | | 48,780 | | 36,889 |
| Bank loans (note 4) | | 52,719 | | 62,404 |
| Convertible debentures (note 5) | | 43,460 | | - |
| Asset retirement obligations (note 6) | | 36,320 | | 33,879 |
| Future income taxes (note 7) | | <u>20,045</u> | | <u>31,278</u> |
| | | 201,324 | | 164,450 |
| Shareholders' equity: | | | | |
| Share capital (note 8) | | 422,038 | | 391,637 |
| Equity component of convertible debentures (note 5) | | 4,242 | | - |
| Contributed surplus (note 8) | | 8,164 | | 6,104 |
| Deficit | | <u>(100,653)</u> | | <u>(65,022)</u> |
| | | 333,791 | | 332,719 |
| Commitments (note 13) | | | | |
| Subsequent event (note 14) | | | | |
| | \$ | <u>535,115</u> | \$ | <u>497,169</u> |

See accompanying notes to the consolidated financial statements.

ANDERSON ENERGY LTD.
Consolidated Statements of Operations, Comprehensive Loss and Deficit

YEARS ENDED DECEMBER 31, 2010 AND 2009

(Stated in thousands of dollars, except per share amounts)
(Unaudited)

| | 2010 | 2009 |
|---|---------------------|--------------------|
| REVENUES | | |
| Oil and gas sales | \$ 86,457 | \$ 76,993 |
| Royalties | (9,011) | (8,253) |
| Realized loss on derivative contracts | (131) | - |
| Unrealized loss on derivative contracts (note 11) | (1,918) | - |
| Interest income | <u>96</u> | <u>155</u> |
| | 75,493 | 68,895 |
| EXPENSES | | |
| Operating | 29,148 | 26,906 |
| General and administrative | 7,733 | 6,998 |
| Stock-based compensation | 1,175 | 1,092 |
| Interest and other financing charges | 3,352 | 3,733 |
| Depletion, depreciation and accretion | <u>81,265</u> | <u>80,940</u> |
| | <u>122,673</u> | <u>119,669</u> |
| Net loss before taxes | (47,180) | (50,774) |
| Future income tax reduction (note 7) | <u>(11,549)</u> | <u>(14,316)</u> |
| Net loss and comprehensive loss for the year | (35,631) | (36,458) |
| Deficit, beginning of year | <u>(65,022)</u> | <u>(28,564)</u> |
| Deficit, end of year | <u>\$ (100,653)</u> | <u>\$ (65,022)</u> |
| Net loss per share (note 8) | | |
| Basic | \$ (0.21) | \$ (0.29) |
| Diluted | <u>\$ (0.21)</u> | <u>\$ (0.29)</u> |

See accompanying notes to the consolidated financial statements.

ANDERSON ENERGY LTD.

Consolidated Statements of Cash Flows

YEARS ENDED DECEMBER 31, 2010 AND 2009

(Stated in thousands of dollars)
(Unaudited)

2010

2009

CASH PROVIDED BY (USED IN)**OPERATIONS**

| | | | | |
|--|----|--------------|----|----------------|
| Net loss for the year | \$ | (35,631) | \$ | (36,458) |
| Items not involving cash: | | | | |
| Depletion, depreciation and accretion | | 81,265 | | 80,940 |
| Future income tax reduction | | (11,549) | | (14,316) |
| Unrealized loss on derivative contracts <i>(note 11)</i> | | 1,918 | | - |
| Stock-based compensation | | 1,175 | | 1,092 |
| Accretion on convertible debentures <i>(note 5)</i> | | 2 | | - |
| Asset retirement expenditures | | (1,549) | | (1,482) |
| Changes in non-cash working capital <i>(note 10)</i> | | <u>5,365</u> | | <u>(5,956)</u> |
| | | 40,996 | | 23,820 |

FINANCING

| | | | | |
|--|--|------------|--|------------|
| Decrease in bank loans | | (9,685) | | (22,910) |
| Issue of common shares, net of issue costs | | 29,859 | | 56,538 |
| Issue of convertible debentures, net of issue costs | | 47,700 | | - |
| Changes in non-cash working capital <i>(note 10)</i> | | <u>384</u> | | <u>115</u> |
| | | 68,258 | | 33,743 |

INVESTMENTS

| | | | | |
|--|----|--------------|----|-----------------|
| Additions to property, plant and equipment | | (114,380) | | (33,612) |
| Proceeds on disposition of properties | | 2,207 | | 54 |
| Changes in non-cash working capital <i>(note 10)</i> | | <u>6,942</u> | | <u>(24,005)</u> |
| | | (105,231) | | (57,563) |
| Increase in cash | | 4,023 | | - |
| Cash, beginning of year | | <u>1</u> | | <u>1</u> |
| Cash and cash equivalents, end of year | \$ | <u>4,024</u> | \$ | <u>1</u> |
| Cash in bank | | 374 | | 1 |
| Short-term investments | | <u>3,650</u> | | - |
| Cash and cash equivalents | \$ | <u>4,024</u> | \$ | <u>1</u> |

See note 10 for supplemental cash flow information.

See accompanying notes to the consolidated financial statements.

ANDERSON ENERGY LTD.

Notes to the Consolidated Financial Statements

YEARS ENDED DECEMBER 31, 2010 AND 2009
(Tabular amounts in thousands of dollars, unless otherwise stated)
(Unaudited)

Anderson Energy Ltd. ("Anderson Energy" or the "Company") was incorporated under the laws of the province of Alberta on January 30, 2002. Anderson Energy is engaged in the acquisition, exploration and development of oil and gas properties in western Canada.

1. SIGNIFICANT ACCOUNTING POLICIES

(a) Basis of presentation. These consolidated financial statements include the accounts of Anderson Energy Ltd. and its wholly owned subsidiaries and a partnership and have been prepared by management in accordance with accounting principles generally accepted in Canada. All inter-entity transactions and balances have been eliminated. Management is required to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amount of revenue and expenses during the reported period. Actual results could differ from these estimates. Specifically, the amounts recorded for depletion and depreciation of oil and gas properties and the accretion of asset retirement obligations are based on estimates. The ceiling test is based on estimates of reserves, production rates, oil and gas prices, future costs and other relevant assumptions. The amounts for stock-based compensation are based on estimates of risk-free rates, expected lives, forfeitures and volatility. Future income taxes are based on estimates as to the timing of the reversal of temporary differences and tax rates currently substantively enacted. The fair value of derivative contracts are based on the discounted value of the market for future commodity prices, interest rates and the exchange rate between United States and Canadian dollars. By their nature, these estimates are subject to measurement uncertainty and the effect on the financial statements of changes in such estimates in future periods could be significant.

(b) Cash and cash equivalents. Cash is defined as cash in the bank, less outstanding cheques. Cash equivalents consist of term deposits with original maturity dates of less than 30 days.

(c) Property, plant and equipment. The Company follows the full cost method of accounting for oil and gas properties. Under this method, all costs related to the exploration for and development of oil and gas reserves are capitalized. Capitalized costs include lease acquisitions, geological and geophysical costs, lease rentals on non-producing properties, costs of drilling productive and non-productive wells, plant and production equipment costs, asset retirement costs and that portion of general and administrative expenses directly attributable to exploration and development activities. Proceeds received from disposals of oil and gas properties and equipment are credited against capitalized costs unless the disposal would alter the rate of depletion and depreciation by more than 20%, in which case a gain or loss on disposal is recorded.

1. SIGNIFICANT ACCOUNTING POLICIES *(Continued)*

Oil and gas capitalized costs are depleted and depreciated using the unit of production method based on total proved reserves before royalties. Natural gas sales and reserves are converted to equivalent units of crude oil using their relative energy content. The costs of acquiring and evaluating unproved properties are initially excluded from depletion calculations until it is determined whether or not proved reserves are attributable to the property or impairment occurs. Office equipment and furniture are being depreciated over their useful lives using the declining balance method at rates between 20% and 30% per annum.

A detailed impairment calculation is performed when events or circumstances indicate a potential impairment of the carrying amount of oil and gas properties may have occurred, and at least annually in the fourth quarter. An impairment loss is recognized when the carrying amount of a cost centre is not recoverable and exceeds its fair value. The carrying amount is assessed to be recoverable when the sum of the undiscounted cash flows expected from proved reserves plus the cost of unproved properties, net of impairments, exceeds the carrying amount of the cost centre. When the carrying amount is assessed not to be recoverable, an impairment loss is recognized to the extent that the carrying amount of the cost centre exceeds the sum of the discounted cash flows from proved and probable reserves plus the cost of unproved properties, net of impairments, of the cost centre. The cash flows are estimated using expected future product prices and costs and are discounted using a risk-free interest rate.

(d) Asset retirement obligations. The Company records the fair value of asset retirement obligations as a liability in the period in which it incurs a legal obligation to restore an oil and gas property, typically when a well is drilled, equipment is put in place or in the event of an acquisition. The fair value is discounted using the Company's credit adjusted, risk-free rate with the associated asset retirement costs capitalized as part of the carrying amount of property, plant and equipment and depleted and depreciated using the unit of production method based on total proved reserves before royalties. Subsequent to the initial measurement of the obligations, the obligations are increased at the end of each period to reflect the passage of time resulting in an accretion charge to earnings. The obligations are also adjusted for changes in the estimated future cash flows underlying the obligation. Actual costs incurred upon settlement of the retirement obligation are charged against the obligation to the extent of the liability recorded.

(e) Income taxes. The Company follows the asset and liability method of accounting for income taxes. Under this method, income tax assets and liabilities are recognized for the estimated tax consequences attributable to differences between the amounts reported in the financial statements and their respective tax bases, using income tax rates that are substantively enacted and expected to apply in the periods when the temporary differences are expected to reverse. The effect of a change in rates on future income tax assets and liabilities is recognized in the period that the change occurs.

(f) 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. An estimate of the additional tax liability to be incurred and included in the future tax provision is recognized and charged to share capital at the time the resource expenditure deductions for income tax purposes are renounced to investors.

1. SIGNIFICANT ACCOUNTING POLICIES *(Continued)*

(g) Stock-based compensation plans. The Company accounts for stock options granted to employees and directors using the fair value method of accounting for stock-based compensation plans. Under this method, the Company recognizes compensation expense, with a corresponding increase to contributed surplus, based on the fair value of the options over the vesting period of the grant. The Company uses a Black-Scholes option pricing model to determine the fair value of options at the date of grant. When exercised, the consideration paid together with the amount previously recognized in contributed surplus is recorded as an increase to share capital.

(h) Revenue recognition. Revenue from the sale of oil and gas is recognized when title passes from the Company to the purchaser.

(i) Financial instruments. A financial instrument is any contract that gives rise to a financial asset to one entity and a financial liability or equity instrument to another entity. Upon initial recognition, all financial instruments, including all derivatives, are recognized on the balance sheet at fair value. Subsequent measurement is then based on the financial instruments being classified into one of five categories: held for trading, held to maturity, loans and receivables, available for sale and other liabilities. The Company has designated its cash and cash equivalents as held for trading which is measured at fair value. Accounts receivable are classified as loans and receivables which are measured at amortized cost. Accounts payable and accrued liabilities, bank loans and the liability component of convertible debentures are classified as other liabilities which are measured at amortized cost determined using the effective interest rate.

The Company is exposed to market risks resulting from fluctuations in commodity prices, foreign exchange rates and interest rates in the normal course of operations. A variety of derivative instruments may be used by the Company to reduce its exposure to fluctuations in commodity prices, foreign exchange rates, and interest rates. The Company does not use these derivative instruments for trading or speculative purposes. The Company considers all of these transactions to be economic hedges, however, the Company's contracts do not qualify or have not been designated as hedges for accounting purposes. As a result, derivative contracts are classified as held for trading and are recorded on the balance sheet at fair value, with changes in the fair value recognized in earnings, unless specific hedge criteria are met. If specific hedge criteria are met, changes in the fair value are initially recognized in other comprehensive income, and are subsequently reclassified to earnings in the same period in which the revenues associated with the hedged transactions are recognized. The fair values of these derivative instruments are based on an estimate of the amounts that would have been received or paid to settle these instruments prior to maturity given future market prices and other relevant factors.

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

1. SIGNIFICANT ACCOUNTING POLICIES *(Continued)*

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

The Company nets all transaction costs incurred, in relation to the acquisition of a financial asset or liability, against the related financial asset or liability. Convertible debentures are recorded net of issue costs and bank loans are presented net of deferred interest payments, with interest recognized in earnings on an effective interest basis.

The Company applies trade-date accounting for the recognition of a purchase or sale of cash equivalents and derivative contracts.

(j) Convertible debentures. The Company's convertible debentures are financial liabilities consisting of a liability with an embedded conversion feature. As such, the debentures are segregated between liabilities and equity based on the residual value method, where the liability is first measured using a discount rate without the conversion feature and the remaining amount is allocated to equity. Therefore, the debenture liabilities are presented at less than their maturity values. The liability and equity components are further reduced for issuance costs initially incurred. The difference between the discounted liability component and the maturity value is accreted by the "effective interest" method over the debenture term and expensed accordingly. As debentures are converted to shares, an appropriate portion of the liability and equity components are transferred to share capital.

(k) Interests in joint operations. A substantial portion of the Company's oil and gas exploration and development activities are conducted jointly with others, and accordingly, the consolidated financial statements reflect only the Company's proportionate interest in such activities.

(l) Per share amounts. Basic per share amounts are calculated using the weighted average number of common shares outstanding during the period. Diluted per share amounts reflect the potential dilution that could occur if securities or other contracts to issue common shares were exercised or converted to common shares. The treasury stock method is used to determine the dilutive effect of stock options and other dilutive instruments. Under the treasury stock method, only options for which the exercise price is less than the market value impact the dilution calculations.

(m) Comparative figures. Certain comparative figures have been reclassified to conform to the current year's presentation.

2. FUTURE ACCOUNTING PRONOUNCEMENTS

Convergence with International Financial Reporting Standards ("IFRS"). In January 2006, the Canadian Accounting Standards Board ("AcSB") announced its decision to replace Canadian GAAP with IFRS. On February 13, 2008, the AcSB confirmed January 1, 2011 as the mandatory changeover date to IFRS for all Canadian publicly accountable enterprises. As a result, Anderson Energy will prepare its financial statements under IFRS for the interim periods and fiscal year ends beginning in 2011.

3. PROPERTY, PLANT AND EQUIPMENT

| | <i>2010</i> | <i>2009</i> |
|---|-------------------|-------------------|
| Cost | \$ 838,405 | \$ 723,549 |
| Less accumulated depletion and depreciation | (331,872) | (253,149) |
| Net book value | \$ 506,533 | \$ 470,400 |

At December 31, 2010, unproved property costs of \$5.0 million (December 31, 2009 – \$6.2 million) have been excluded from the full cost pool for depletion and depreciation calculations. Future development costs of proved, undeveloped reserves of \$137.0 million (December 31, 2009 – \$197.6 million) have been included in the depletion and depreciation calculation.

For the year ended December 31, 2010, \$5.2 million (December 31, 2009 – \$4.6 million) of general and administrative costs including \$0.9 million (December 31, 2009 – \$1.0 million) of stock-based compensation costs were capitalized. The future tax liability of \$0.3 million (December 31, 2009 – \$0.3 million) associated with the capitalized stock-based compensation has also been capitalized. Capitalized general and administrative costs consist of salaries and associated office rent of staff involved in capital activities.

No impairment was recognized under the ceiling test at December 31, 2010. The future commodity prices used in the ceiling test were based on commodity price forecasts of the Company's independent reserves engineers adjusted for differentials specific to the Company's reserves. Factors used in the ceiling test calculation are as follows:

| | <i>AECO Gas Price (\$Cdn/Mcf)</i> | <i>WTI Cushing (\$US/bbl)</i> | <i>Exchange rate (US\$/Cdn)</i> |
|----------------------|---------------------------------------|-----------------------------------|-------------------------------------|
| 2011 | 4.16 | 88.00 | 0.98 |
| 2012 | 4.74 | 89.00 | 0.98 |
| 2013 | 5.31 | 90.00 | 0.98 |
| 2014 | 5.77 | 92.00 | 0.98 |
| 2015 | 6.22 | 95.17 | 0.98 |
| 2016 | 6.53 | 97.55 | 0.98 |
| 2017 | 6.76 | 100.26 | 0.98 |
| 2018 | 6.90 | 102.74 | 0.98 |
| 2019 | 7.06 | 105.45 | 0.98 |
| 2020 | 7.21 | 107.56 | 0.98 |
| <u>Thereafter 2%</u> | | | |

After 2020, only inflationary growth of 2% was considered. Natural gas liquids prices were tied to crude oil prices based on historical trends and analysis. Exchange rates were expected to remain constant beyond 2020.

4. BANK LOANS

At December 31, 2010, total bank facilities were \$125 million consisting of an \$80 million extendible revolving term credit facility, a \$10 million working capital credit facility and a \$35 million supplemental credit facility, with a syndicate of Canadian banks. The extendible revolving term credit facility and working capital credit facility have a revolving period ending on July 12, 2011, extendible at the option of the lenders. If not extended, these facilities cease to revolve and all outstanding advances thereunder become repayable one year from the term date of July 12, 2011. The supplemental facility is also available on a revolving basis and is scheduled to expire on July 1, 2011, with any outstanding amounts due in full at that time.

4. **BANK LOANS** *(Continued)*

At December 31, 2010 there were no amounts drawn under the supplemental facility. The average effective interest rate on advances in 2010 was 4.9% (December 31, 2009 – 4.2%). The Company had \$133,500 in letters of credit outstanding at December 31, 2010, which reduced the amount of credit available to the Company.

Advances under the facilities can be drawn in either Canadian or U.S. funds and bear interest at the bank's prime lending rate, bankers' acceptance or LIBOR loan rates plus applicable margins. The margins vary depending on the borrowing option used and the Company's financial ratios. At December 31, 2010 there were no advances in U.S. funds.

Loans are secured by a floating charge debenture over all assets and guarantees by material subsidiaries. Draws over \$30 million under the supplemental facility will be subject to the consent of the bank syndicate at the time of the drawdown.

The available lending limits of the facilities are reviewed semi-annually and are based on the bank syndicate's interpretations of the Company's reserves and future commodity prices. There can be no assurance that the amount of the available facilities or the applicable margins will not be adjusted at the next scheduled review on or before July 12, 2011.

5. **CONVERTIBLE DEBENTURES**

On December 31, 2010, the Company issued \$50 million of convertible unsecured subordinated debentures (the "Debentures") on a bought deal basis. The Debentures have a face value of \$1,000, bear interest at the rate of 7.5% per annum payable semi-annually in arrears on the last day of January and July of each year commencing on July 31, 2011 and mature on January 31, 2016 (the "Maturity Date"). The Debentures are convertible at the holder's option at a conversion price of \$1.55 per common share (the "Conversion Price"), subject to adjustment in certain events. The Debentures are not redeemable by the Corporation before January 31, 2014. On and after January 31, 2014 and prior to the Maturity Date, the Debentures are redeemable at the Corporation's option, in whole or in part, at a price equal to their principal amount plus accrued and unpaid interest if the weighted average trading price of the common shares on the Toronto Stock Exchange for the 20 consecutive trading days preceding the date on which the notice of redemption is given is not less than 125% of the Conversion Price. The Debentures are listed and posted for trading on the TSX under the symbol "AXL.DB".

As the Debentures are convertible into common shares, the liability and equity components are presented separately. The initial carrying amount of the financial liability is determined by discounting the stream of future payments of interest and principal. Using the residual method, the carrying amount of the conversion feature is the difference between the principal amount and the carrying value of the financial liability. The Debentures, net of the equity component and issue costs are accreted using the effective interest rate method over the term of the Debentures such that the carrying amount of the financial liability will equal the principal balance at maturity.

5. CONVERTIBLE DEBENTURES *(Continued)*

There were no convertible debentures outstanding at December 31, 2009. The following table indicates the convertible debenture activities for the year ended December 31, 2010:

| | <i>Face Value</i> | <i>Debt Component</i> | <i>Equity Component</i> |
|--|-----------------------|---------------------------|-----------------------------|
| Balance, December 31, 2009 | \$ - | \$ - | \$ - |
| Issued pursuant to prospectus ⁽¹⁾ | 50,000 | 45,553 | 4,447 |
| Issue costs | (2,300) | (2,095) | (205) |
| Accretion expense | - | 2 | - |
| Balance, December 31, 2010 | <u>\$ 47,700</u> | <u>\$ 43,460</u> | <u>\$ 4,242</u> |

(1) Includes 1,000 Debentures issued to directors for total gross proceeds of \$1.0 million.

6. ASSET RETIREMENT OBLIGATIONS

The Company estimates the total undiscounted cash flows required to settle its asset retirement obligations is approximately \$73.7 million (December 31, 2009 – \$70.1 million), including expected inflation of 2% (December 31, 2009 – 2%) per annum. The majority of the costs will be incurred between 2011 and 2030. A credit adjusted risk-free rate of 8% to 10% (December 31, 2009 – 8% to 10%) was used to calculate the fair value of the asset retirement obligations. A reconciliation of the asset retirement obligations is provided below:

| | <i>2010</i> | <i>2009</i> |
|----------------------------|------------------|------------------|
| Balance, beginning of year | \$ 33,879 | \$ 30,820 |
| Liabilities incurred | 758 | 1,544 |
| Liabilities settled | (1,549) | (1,482) |
| Change in estimate | 690 | 666 |
| Accretion expense | 2,542 | 2,331 |
| Balance, end of year | <u>\$ 36,320</u> | <u>\$ 33,879</u> |

7. TAXES

The temporary differences that gave rise to the Company's future income tax liabilities (assets) at December 31, 2010 and 2009 were as follows:

| | <i>2010</i> | <i>2009</i> |
|---|------------------|------------------|
| Future income tax liabilities (assets): | | |
| Property, plant and equipment | \$ 46,073 | \$ 50,210 |
| Non-capital losses | (18,080) | (9,289) |
| Asset retirement obligations | (9,080) | (8,470) |
| Share issue costs | (2,229) | (1,985) |
| Current income deferred | 2,853 | 812 |
| Balance, end of year | <u>\$ 19,537</u> | <u>\$ 31,278</u> |
| Future income tax asset | \$ (508) | \$ - |
| Future income tax liability | <u>20,045</u> | <u>31,278</u> |
| | <u>\$ 19,537</u> | <u>\$ 31,278</u> |

7. TAXES (Continued)

The provision for income taxes differs from the result that would have been obtained by applying the combined federal and provincial tax rates to the loss before income taxes. The difference results from the following items:

| | 2010 | 2009 |
|---|-------------|-------------|
| Loss before taxes | \$ (47,180) | \$ (50,774) |
| Combined federal and provincial tax rates | 28.0% | 29.0% |
| Expected future income tax reduction | (13,210) | (14,724) |
| Increase in income taxes resulting from: | | |
| Changes in expected future tax rates | 1,339 | 108 |
| Non-deductible stock-based compensation and other | 322 | 300 |
| Future income tax reduction | \$ (11,549) | \$ (14,316) |

At December 31, 2010, the Company has loss carryforwards of \$72 million that will expire between 2025 and 2030. The Company expects to be able to fully utilize these losses.

8. SHARE CAPITAL AND CONTRIBUTED SURPLUS

Authorized share capital. The Company is authorized to issue an unlimited number of common and preferred shares. The preferred shares may be issued in one or more series.

Issued share capital.

| | Number of Common Shares | Amount |
|---|----------------------------|------------|
| Balance at December 31, 2008 | 87,300,401 | \$ 334,176 |
| Issued pursuant to prospectus ⁽¹⁾ | 63,200,000 | 60,040 |
| Share issue costs | - | (3,502) |
| Tax effect of share issue costs | - | 923 |
| Balance at December 31, 2009 | 150,500,401 | \$ 391,637 |
| Issued pursuant to prospectus ⁽²⁾ | 21,900,000 | 31,755 |
| Share issue costs | - | (1,963) |
| Tax effect of share issue costs | - | 507 |
| Stock options exercised | 84,900 | 67 |
| Transferred from contributed surplus on stock option exercise | - | 35 |
| Balance at December 31, 2010 | 172,485,301 | \$ 422,038 |

(1) Includes 4,992,034 common shares issued to management and directors and 3,377,966 common shares issued to family of management and directors for total gross proceeds of \$8.0 million.

(2) Includes 352,466 common shares issued to directors for total gross proceeds of \$0.5 million.

Stock options. The Company has an employee stock option plan under which employees, directors and consultants are eligible to receive grants. The exercise price of stock options equals the weighted average trading price of the Company's shares for the five trading days prior to the date of the grant. Options have terms of either five or ten years and vest equally over a three year period starting on the first anniversary date of the grant. Changes in the number of options outstanding during the years ended December 31, 2010 and December 31, 2009 are as follows:

8. SHARE CAPITAL AND CONTRIBUTED SURPLUS (Continued)

| | Number of options | | Weighted average exercise price |
|----------------------------------|----------------------|----|---------------------------------------|
| Balance at December 31, 2008 | 7,594,856 | \$ | 4.37 |
| Granted | 3,316,200 | | 0.80 |
| Expirations | (252,300) | | 6.47 |
| Forfeitures | (400,000) | | 3.01 |
| Balance at December 31, 2009 | 10,258,756 | \$ | 3.22 |
| Granted | 3,950,250 | | 1.06 |
| Exercised | (84,900) | | 0.79 |
| Expirations | (1,430,124) | | 5.78 |
| Forfeitures | (687,750) | | 1.44 |
| Balance at December 31, 2010 | 12,006,232 | \$ | 2.32 |
| | | | |
| Exercisable at December 31, 2010 | 6,111,399 | \$ | 3.53 |

| Range of exercise prices | Options outstanding | | | Options exercisable | |
|----------------------------|----------------------|--|--|----------------------|--|
| | Number of options | Weighted average exercise price | Weighted average remaining life (years) | Number of options | Weighted average exercise price |
| \$0.79 to \$0.99 | 2,706,900 | \$ 0.79 | 3.6 | 902,300 | \$ 0.79 |
| \$1.00 to \$1.50 | 3,831,750 | 1.06 | 4.6 | 29,400 | 1.09 |
| \$2.26 to \$3.35 | 727,950 | 2.68 | 2.7 | 489,300 | 2.68 |
| \$3.36 to \$5.00 | 4,354,732 | 4.00 | 1.5 | 4,308,499 | 4.00 |
| \$5.01 to \$7.50 | 320,100 | 5.67 | 0.3 | 317,100 | 5.68 |
| \$7.51 to \$9.01 | 64,800 | 7.69 | 0.1 | 64,800 | 7.69 |
| Total at December 31, 2010 | 12,006,232 | \$ 2.32 | 3.0 | 6,111,399 | \$ 3.53 |

The fair value of the options issued during the year ended December 31, 2010 was \$0.55 per option (December 31, 2009 – \$0.42 per option). The weighted average assumptions used in arriving at the values were: a risk-free interest rate of 2.3% (December 31, 2009 – 2.4%), expected option life of five years (December 31, 2009 – five years), expected volatility of 58% (December 31, 2009 – 60%) and a dividend yield of 0% (December 31, 2009 – 0%).

Per share amounts. During the year ended December 31, 2010 there were 170,298,490 weighted average shares outstanding (December 31, 2009 – 125,047,250). On a diluted basis, there were 170,298,490 weighted average shares outstanding (December 31, 2009 – 125,047,250) after giving effect to dilutive stock options and dilutive convertible debentures. At December 31, 2010, there were 12,006,232 options (December 31, 2009 – 10,258,756) and 32,258,065 common shares reserved for convertible debentures (December 31, 2009 – Nil) that were anti-dilutive.

Contributed surplus

| | Amount |
|---|----------|
| Balance at December 31, 2008 | \$ 4,000 |
| Stock-based compensation | 2,104 |
| Balance at December 31, 2009 | \$ 6,104 |
| Stock-based compensation | 2,095 |
| Transferred from contributed surplus on stock option exercise | (35) |
| Balance at December 31, 2010 | \$ 8,164 |

9. MANAGEMENT OF CAPITAL STRUCTURE

Anderson Energy's capital management policy is to maintain a strong, but flexible capital structure that optimizes the cost of capital and maintains investor, creditor and market confidence while sustaining the future development of the business.

The Company manages its capital structure and makes adjustments to it in the light of changes in economic conditions and the risk characteristics of the underlying petroleum and natural gas assets. The Company's capital structure includes shareholders' equity of \$333.8 million, bank loans of \$52.7 million, convertible debentures with a face value of \$50.0 million and the working capital deficiency of \$18.8 million, excluding the unrealized loss on derivative contract and future income tax asset. In order to maintain or adjust the capital structure, the Company may from time to time issue shares, seek additional debt financing and adjust its capital spending to manage current and projected debt levels.

Consistent with other companies in the oil and gas sector, Anderson Energy monitors capital based on the ratio of total debt to funds from operations. This ratio is calculated by dividing total debt at the end of the period (comprised of the working capital deficiency, the liability component of convertible debentures and outstanding bank loans) by the annualized current quarter funds from operations (cash flow from operating activities before changes in non-cash working capital and asset retirement expenditures). This ratio may increase at certain times as a result of acquisitions, the timing of capital expenditures and market conditions. In order to facilitate the management of this ratio, the Company prepares annual capital expenditure budgets, which are updated as necessary depending on varying factors including current and forecast crude oil and natural gas prices, capital deployment and general industry conditions. The annual and updated budgets are approved by the Board of Directors.

| | <i>2010</i> | | <i>2009</i> |
|--|-------------|----|-------------|
| Bank loans | \$ 52,719 | \$ | 62,404 |
| Current liabilities, excluding unrealized loss on derivative contracts | 46,862 | | 36,889 |
| Current assets, excluding future income tax asset | (28,074) | | (26,769) |
| Net debt before convertible debentures | \$ 71,507 | \$ | 72,524 |
| Convertible debentures (liability component) | 43,460 | | - |
| Total net debt | \$ 114,967 | \$ | 72,524 |
| Cash from operating activities in quarter | \$ 10,721 | \$ | 5,361 |
| Changes in non-cash working capital | (1,324) | | 3,246 |
| Asset retirement expenditures | 118 | | 544 |
| Funds from operations in quarter | \$ 9,515 | \$ | 9,151 |
| Annualized current quarter funds from operations | \$ 38,060 | \$ | 36,604 |
| Net debt before convertible debentures to funds from operations | 1.9 | | 2.0 |
| Total net debt to funds from operations | 3.0 | | 2.0 |

At December 31, 2010, the Company's total net debt to annualized funds from operations was 3.0 and the Company's net debt before convertible debentures to annualized funds from operations was 1.9. At December 31, 2009, the Company's total debt to annualized funds from operations was 2.0. The increase in the total net debt to funds from operations ratio in the fourth quarter of 2010 is due to \$26.5 million in capital expenditures and lower natural gas prices in the quarter as well as the issuance of 50,000 convertible debentures on December 31, 2010. Net debt before convertible debentures to annualized funds from operation in 2010 was relatively consistent with 2009. New production resulting from the

9. MANAGEMENT OF CAPITAL STRUCTURE *(Continued)*

capital expenditures is not yet reflected in the reported funds from operations. As this new crude oil production is brought on stream at higher expected operating margins, the debt to funds from operations ratio is expected to decrease.

The Company's share capital is not subject to external restrictions, however, its credit facilities are petroleum and natural gas reserves based (see note 4). Anderson Energy has not paid or declared any dividends since the date of incorporation and does not contemplate doing so in the foreseeable future.

10. SUPPLEMENTAL CASH FLOW INFORMATION

| | <i>2010</i> | <i>2009</i> |
|---|------------------|--------------------|
| Change in non-cash working capital: | | |
| Accounts receivable and accruals | \$ 1,992 | \$ 5,970 |
| Prepaid expenses and deposits | 726 | (1,086) |
| Accounts payable and accruals | 9,973 | (34,730) |
| <u>Change in non-cash working capital</u> | <u>\$ 12,691</u> | <u>\$ (29,846)</u> |
| Relating to: | | |
| Operating activities | \$ 5,365 | \$ (5,956) |
| Financing activities | 384 | 115 |
| Investing activities | 6,942 | (24,005) |
| <u>Change in non-cash working capital</u> | <u>\$ 12,691</u> | <u>\$ (29,846)</u> |

The following cash payments were made (received):

| | <i>2010</i> | <i>2009</i> |
|--------------------------|-------------|--------------|
| Interest paid | \$ 2,256 | \$ 2,835 |
| <u>Interest received</u> | <u>(90)</u> | <u>(155)</u> |

11. FINANCIAL INSTRUMENTS AND FINANCIAL RISK MANAGEMENT

The Company's financial instruments include cash and cash equivalents, accounts receivable and accruals, deposits, accounts payable and accruals, bank loans, convertible debentures and forward price contracts.

The Company's risk management policies are established to identify and analyze the risks faced by the Company, to set appropriate risk limits and controls, and to monitor risks and adherence to market conditions and the Company's activities.

The Company has exposure to credit risk, liquidity risk and market risk as a result of its use of financial instruments. This note presents information about the Company's exposure to each of the above risks and the Company's objectives, policies and processes for measuring and managing these risks. Further quantitative disclosures are included throughout these financial statements.

The Board of Directors has overall responsibility for the establishment and oversight of the Company's risk management framework. The Board has implemented and monitors compliance with risk management policies.

11. FINANCIAL INSTRUMENTS AND FINANCIAL RISK MANAGEMENT *(Continued)*

Fair value of financial asset and financial liabilities. Financial instruments measured at fair value on the balance sheet require classification into one of the following levels of fair value hierarchy:

- Level 1 – observable inputs such as quoted prices in active markets;
- Level 2 – inputs, other than the quoted market prices in active markets, which are observable, either directly and/or indirectly; and
- Level 3 – unobservable inputs for the asset or liability in which little or no market data exists, therefore requiring an entity to develop its own assumptions.

Cash and cash equivalents as shown in the consolidated balance sheet as at December 31, 2010 and 2009, is measured using level 1. The commodity contracts are classified as level 2 within the fair value hierarchy. The Company does not have any financial instruments that are measured using level 3 inputs.

During the years ended December 31, 2010 and 2009, there were no transfers between level 1, level 2 and level 3 classified assets and liabilities.

Cash and cash equivalents. The fair value of cash and cash equivalents approximates its carrying value due to its short-term nature.

Accounts receivable and accruals, accounts payable and accruals. The carrying amount of accounts receivable and accruals and accounts payable and accruals approximate their fair values due to the short-term nature of the instruments.

Bank loans. The fair value of the Company's variable-rate bank loans approximates its carrying value, as it is at a floating market rate of interest.

Convertible debentures. The liability component has been classified as other liabilities and measured at amortized cost. The convertible debentures have a fixed term and interest rate (note 5) resulting in fair values that will vary over time as market conditions change. The fair value of the liability component of convertible debentures was determined based on a discounted cash flow model assuming no future conversions and continuation of current interest and principal payments as well as taking into consideration the current public trading activity of such debentures. The Company applied a discount rate of 10% considering current available market information, assumed credit adjustments and term to maturity.

Forward crude oil price swap. The Company may manage the risk associated with changes in commodity prices by entering into derivatives, which are recorded at fair value as derivative assets and liabilities with gains and losses recognized through earnings. As the fair value of the contracts varies with commodity prices, they give rise to financial assets and liabilities. The fair values of the derivatives are determined by a Level 2 valuation model, where pricing inputs other than quoted prices in an active market are used. These pricing inputs include quoted forward prices for commodities, foreign exchange rates, volatility and risk-free rate discounting, all of which can be observed or corroborated in the marketplace. The actual gains and losses realized on eventual cash settlement can vary materially due to subsequent fluctuations in commodity prices and foreign exchange rates as compared to the valuation assumptions.

11. FINANCIAL INSTRUMENTS AND FINANCIAL RISK MANAGEMENT *(Continued)*

Credit risk. Credit risk is the risk of financial loss to the Company if a customer or counterparty to a financial instrument fails to meet its contractual obligations. A substantial portion of the Company's accounts receivable are with natural gas and liquids marketers and joint venture partners in the oil and gas industry and are subject to normal industry credit risks. Purchasers of the Company's natural gas and liquids are subject to credit review to minimize the risk of non-payment. As at December 31, 2010, the maximum credit exposure is the carrying amount of the accounts receivable and accruals of \$21.0 million (December 31, 2009 – \$23.0 million). As at December 31, 2010, the Company's receivables consisted of \$11.4 million (December 31, 2009 – \$14.4 million) from joint venture partners and other trade receivables and \$9.6 million (December 31, 2009 – \$8.6 million) of revenue accruals and other receivables from petroleum and natural gas marketers.

Receivables from petroleum and natural gas marketers are typically collected on the 25th day of the month following production. The Company's policy to mitigate credit risk associated with these balances is to establish marketing relationships with large purchasers. The Company historically has not experienced any significant collection issues with its petroleum and natural gas marketers. Of the \$9.6 million of revenue accruals and receivables from petroleum and natural gas marketers, \$8.5 million was received on or about January 25, 2011. The balance is expected to be received in subsequent months through joint venture billings from partners.

Joint venture receivables are typically collected within one to three months of the joint venture bill being issued to the partner. The Company mitigates the risk from joint venture receivables by obtaining partner approval of capital expenditures prior to starting a project. However, the receivables are from participants in the petroleum and natural gas sector, and collection is dependent on typical industry factors such as commodity price fluctuations, escalating costs and the risk of unsuccessful drilling. Further risks exist with joint venture partners, as disagreements occasionally arise that increase the potential for non-collection. For properties that are operated by Anderson Energy, production can be withheld from joint venture partners who are in default of amounts owing. In addition, the Company often has offsetting amounts payable to joint venture partners from which it can net receivable balances. At December 31, 2010, the largest amount owing from one partner is \$0.8 million.

The Company is from time to time exposed to credit risk associated with possible non-performance by counterparties to derivative financial instrument contracts. The Company believes these risks to be minimal as the counterparties are major financial institutions.

The Company's allowance for doubtful accounts as at December 31, 2010 is \$1.0 million (December 31, 2009 – \$1.6 million). This allowance was mostly created in prior years and is associated with prior corporate acquisitions and potential joint venture billing disputes. The Company wrote-off \$0.6 million in receivables during the year ended December 31, 2010 (December 31, 2009 – \$Nil). The Company would only choose to write-off a receivable balance (as opposed to providing an allowance) after all reasonable avenues of collection had been exhausted.

11. FINANCIAL INSTRUMENTS AND FINANCIAL RISK MANAGEMENT *(Continued)*

As at December 31, the Company considers its receivables to be aged as follows

| Aging | 2010 | | 2009 | |
|--------------------------------|-----------|---------------|-----------|---------------|
| Not past due | \$ | 18,960 | \$ | 22,402 |
| Past due by less than 120 days | | 1,706 | | 537 |
| Past due by more than 120 days | | 332 | | 51 |
| Total | \$ | 20,998 | \$ | 22,990 |

These amounts are before offsetting amounts owing to joint venture partners that are included in accounts payable and accrued liabilities.

Liquidity risk. Liquidity risk is the risk that the Company will incur difficulties meeting its financial obligations as they are due. The Company's approach to managing liquidity is to ensure, as far as possible, that it will have sufficient liquidity to meet its liabilities when due, under both normal and stressed conditions without incurring unacceptable losses or risking harm to the Company's reputation.

The Company prepares annual capital expenditure budgets, which are regularly monitored and updated as considered necessary. The Company uses authorizations for expenditures on both operated and non-operated projects to further manage capital expenditures. To facilitate the capital expenditure program, the Company has revolving reserves based credit facilities, as outlined in note 4, which are reviewed semi-annually by the lenders. The Company monitors its total debt position monthly. The Company also attempts to match its payment cycle with collection of petroleum and natural gas revenues on the 25th of each month. The Company anticipates it will have adequate liquidity to fund its financial liabilities through its future cash flows.

The following are the contractual maturities of financial liabilities and associated interest payments as at December 31, 2010:

| Financial Liabilities | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 |
|------------------------------------|------------------|------------------|-----------------|-----------------|-----------------|------------------|
| Accounts payable and accruals | \$ 46,862 | \$ - | \$ - | \$ - | \$ - | \$ - |
| Bank loans – principal | - | 52,719 | - | - | - | - |
| Convertible debentures – interest | 2,198 | 3,750 | 3,750 | 3,750 | 3,750 | 1,875 |
| Convertible debentures – principal | - | - | - | - | - | 50,000 |
| Total | \$ 49,060 | \$ 56,469 | \$ 3,750 | \$ 3,750 | \$ 3,750 | \$ 51,875 |

Please refer to note 13 for additional details on commitments.

Market risk. Market risk consists of currency risk, commodity price risk and interest rate risk. The objective of market risk management is to manage and control market risk exposures within acceptable limits, while maximizing returns.

The Company may use both financial derivatives and physical delivery sales contracts to manage market risks. All such transactions are conducted in accordance with a risk management policy that has been approved by the Board of Directors.

11. FINANCIAL INSTRUMENTS AND FINANCIAL RISK MANAGEMENT *(Continued)*

Currency risk. Foreign currency exchange rate risk is the risk that the fair value or future cash flows will fluctuate as a result of changes in foreign exchange rates. Substantially all of the Company's petroleum and natural gas sales are denominated in Canadian dollars, however, the underlying market prices in Canada for petroleum and natural gas are impacted by changes in the exchange rate between the Canadian and United States dollar. The Company had no outstanding forward exchange rate contracts in place at December 31, 2010.

Commodity price risk. Commodity price risk is the risk that the fair value or future cash flows will fluctuate as a result of changes in commodity prices. Commodity prices for petroleum and natural gas are impacted by world economic events that dictate the levels of supply and demand as well as the relationship between the Canadian and United States dollar, as outlined above. The Company may mitigate commodity price risk through the use of financial derivatives and physical delivery fixed price sales contracts. All such contracts require approval of the Board of Directors.

There were no derivative contracts for the year ended December 31, 2009. As at December 31, 2010, Anderson had a fixed price contract for 1,000 barrels per day of crude oil for calendar 2011 at a NYMEX crude oil price of Canadian \$88.45 per barrel.

The unrealized loss on derivative contracts of \$1.9 million for the year ended December 31, 2010 has been included on the balance sheet as a current liability with changes in the fair value included in unrealized loss on derivative contracts on the consolidated statements of operations. As at December 31, 2010, if the future strip prices for crude oil were \$1 per barrel higher or lower with all other variables held constant, the earnings of the year would have been \$0.4 million lower for the year. An equal and opposite impact would have occurred had future strip prices for crude oil been lower by the same amount.

In October 2010, the Company entered into fixed price swaps for 1,000 barrels per day of crude oil for December 2010 at a NYMEX crude oil price of Canadian \$85.70 per barrel. The Company realized a loss of \$0.1 million in relation to this contract in the year ended December 31, 2010, which is included in the realized loss on derivative contract on the consolidated statements of operations.

In March 2011, the Company entered into a fixed price contract for 250 barrels per day of crude oil for calendar 2012 at a NYMEX crude oil price of Canadian \$103.20 per barrel.

In December 2009, the Company entered into physical sales contracts to sell 20,000 GJ per day of natural gas for each of January, February and March 2010 at an average AECO price of \$5.41 per GJ. The Company realized a gain of \$1.3 million in relation to these physical sales contracts in the year ended December 31, 2010, which is included in oil and gas sales.

Interest rate risk. Interest rate risk is the risk that future cash flows will fluctuate as a result of changes in market interest rates. The Company is exposed to interest rate fluctuations on its bank debt which bears interest at a floating rate. For the year ended December 31, 2010, if interest rates had been 1% lower with all other variables held constant, earnings for the year would have been \$0.3 million (December 31, 2009 – \$0.5 million) higher, due to lower interest expense. An equal and opposite impact would have occurred had interest rates been higher by the same amounts.

The Company had no interest rate swap or financial contracts in place at December 31, 2009.

12. RELATED PARTY TRANSACTIONS

On December 31, 2010, the Company issued 1,000 convertible debentures to directors at a price of \$1,000 per convertible debenture for total gross proceeds of \$1.0 million as part of a \$50.0 million bought share offering of convertible debentures.

In February 2010, the Company issued 352,466 common shares to directors at a price of \$1.45 per share for total gross proceeds of \$0.5 million as part of a \$27.9 million bought share offering of common shares.

In May 2009, the Company issued 4,992,034 common shares to management and directors and 3,377,966 common shares to family of management and directors of the Company at a price of \$0.95 per share for total gross proceeds of \$8.0 million as part of a \$60.0 million bought share offering of common shares.

13. COMMITMENTS

The Company has entered into an agreement to lease office space until November 30, 2012. Future minimum lease payments are expected to be \$1.8 million in 2011 and \$1.6 million in 2012.

On December 2, 2010, the Company entered into a facilities construction and operation agreement pursuant to which it is committed to ship a minimum volume of gross crude oil through new facilities and pipelines being constructed in one of its core areas. The total financial commitment is \$2.6 million to be incurred over a minimum of five years. The contract contains a minimum volume requirement per year for the first five years following completion of construction which is expected to be in the second quarter of 2011. In the event that the volume shipped is less than the minimum volume, the Company will be subject to a fee per cubic metre of oil on the difference between actual volumes shipped and the minimum volume required. Conversely, if the Company exceeds the minimum volume requirement in a single year, the excess is carried forward as a credit to the minimum volume requirement in the subsequent year. If no volumes were shipped, a minimum of \$0.26 million would be payable each year. After the total contracted volumes have been shipped, the contract will automatically renew for one year periods unless terminated.

The Company entered into firm service transportation agreements for approximately 29 million cubic feet per day of gas sales in central Alberta for various terms expiring in one to ten years. Based on rate schedules announced to date, the payments in each of the next five years and thereafter are estimated as follows:

| | <i>Committed volume (MMcfd)</i> | | <i>Committed amount</i> |
|-------------------|---------------------------------|-----------|-------------------------|
| 2011 | 29 | \$ | 1,633 |
| 2012 | 19 | \$ | 1,337 |
| 2013 | 8 | \$ | 825 |
| 2014 | 4 | \$ | 674 |
| 2015 | 4 | \$ | 606 |
| <u>Thereafter</u> | <u>12</u> | <u>\$</u> | <u>442</u> |

13. COMMITMENTS *(Continued)*

On January 29, 2009, the Company executed a farm-in agreement with a large international oil and gas company (the "Farmor") on lands near its existing core operations. Under the farm-in agreement, the Company has access to 388 gross (205 net) sections of land. During the commitment phase of the transaction, the Company is committed to drill, complete and equip 200 wells to earn an interest in up to 120 sections. The Company is obligated to complete the drilling of the wells on or before March 31, 2012. The Company's equipping obligation is up to, but does not include, multi-well gathering systems downstream of field compression and/or gas plants. The Company has an option to continue the farm-in transaction until March 1, 2013 by committing to drill a minimum of 100 additional wells under similar terms as in the commitment phase to earn a minimum of 50 sections of land. Following the commitment and/or option phases, the parties to the agreement can then jointly develop the lands on denser drilling spacing under terms of an operating agreement.

The Company commenced drilling in the fourth quarter of 2009 and currently estimates that the average working interest of the 200 well capital commitment will be approximately 80% to 85%, based on partner participation identified to date. As of December 31, 2010, the Company has drilled 126 wells under the farm-in agreement and plans to defer the drilling of the remaining 74 wells until 2012. The Company earns its interest in each well as the well is put on production. A \$550,000 penalty is payable for each well not drilled under the commitment as of March 31, 2012, subject to certain reductions due to unavoidable events beyond the Company's control and rights of first refusal. The Company estimates that its minimum commitment to drill the remaining 74 wells is \$10 million.

14. SUBSEQUENT EVENT

On February 9, 2011, the Company disposed of properties for gross proceeds of \$5.1 million.

Corporate Information

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Member of:
(1) Audit Committee
(2) Compensation & Corporate
Governance Committee
(3) Reserves Committee

Auditors

KPMG LLP

Independent Engineers

GLJ Petroleum Consultants

Legal Counsel

Bennett Jones LLP

Registrar & Transfer Agent

Valiant Trust Company

Stock Exchange

The Toronto Stock Exchange
Symbol AXL, AXL.DB

Contact Information

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Officers

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Chairman of the Board

Brian H. Dau
President & Chief Executive Officer

David M. Spyker
Chief Operating Officer

M. Darlene Wong
Vice President Finance, Chief Financial
Officer & Secretary

Blaine M. Chicoine
Vice President, Operations

Sandra M. Drinnan
Vice President, Land

Philip A. Harvey
Vice President, Exploitation

Jamie A. Marshall
Vice President, Exploration

Patrick M. O'Rourke
Vice President, Production

Abbreviations used

AECO – intra-Alberta Nova inventory transfer price
bbl – barrel
bpd – barrels per day
Mbbbls – thousand barrels
Mstb – thousand stock tank barrels
BOE – barrels of oil equivalent
BOED – barrels of oil equivalent per day
MBOE – thousand barrels of oil equivalent
MMBOE – million barrels of oil equivalent
GJ – gigajoule
Mcf – thousand cubic feet
Mcmcf – thousand cubic feet per day
MMcf – million cubic feet
MMcmcf – million cubic feet per day
Bcf – billion cubic feet
NGL – natural gas liquids