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## Anderson Energy Announces 2011 First Quarter Results

Calgary, Alberta, May 16, 2011 - Anderson Energy Ltd. ("Anderson Energy" or the "Company") (TSX:AXL) is pleased to announce its operating and financial results for the three months ended March 31, 2011.

### HIGHLIGHTS:

- Cash flow from operations in the first quarter of 2011 was \$10.9 million, up 17% from the fourth quarter of 2010. Total production was 7,726 BOED as compared to 7,000 BOED in the first quarter of 2010. Oil and NGL production in the first quarter of 2011 averaged 2,071 bpd, up 83% from the first quarter of 2010 and 14% from the fourth quarter of 2010. Oil production made up 1,372 bpd of the total and was 298% higher than the first quarter of 2010 and 38% higher than the fourth quarter of 2010.
- In the first and second quarters of 2011, 19 gross (13.8 net) Cardium horizontal oil wells were drilled. All of these oil wells were placed on production as of May 16, 2011. Current Cardium production is 2,300 to 2,400 BOED (85% oil and NGL).
- The Board of Directors has approved an increase in the Company's capital program from \$75 million to \$115 million. Associated production guidance with this expanded capital program is 7,500 to 8,000 BOED. In 2011, the Company estimates it could drill up to 44 gross (28.6 net) Cardium horizontal oil wells, of which 19 gross (13.8 net) have been drilled to date in 2011.
- On May 13, 2011, the Company entered into an agreement with its lenders to renew its credit facilities and increased the total amount of its facilities from \$125 million to \$135 million, subject to execution of customary documentation and normal closing conditions.
- Drill ready Cardium horizontal oil location inventory stands at 188 gross (116.2 net) locations, a 36% increase since December 31, 2010 and a 4.5% increase since our March 28, 2011 press release. The Company has increased the Cardium prospective land that it owns or controls to 115 gross (68.3 net) sections (85% in the oil fairway). Using an industry standard disclosure of three wells per section drilling density, the drilling inventory would be 204 net locations.
- In Garrington, current working interest production is 1,300 BOPD from 17 net Cardium horizontal oil wells. Tank battery and gathering system consolidation and pipeline connections are ongoing and are expected to be complete by August 2011.
- The Company has recently completed its best performing well in the Garrington field. This 100% working interest well was fracture stimulated with a 19 stage gelled water frac and has flowed back 4,000 bbls of reservoir oil in its first seven days of production, at varying rates of 278 to 1,144 BOPD and at time of writing of this press release was flowing at 300 BOPD.

## FINANCIAL AND OPERATING HIGHLIGHTS

|  | Three months ended March 31 |             | % Change |
|--|-----------------------------|-------------|----------|
|  | 2011                        | 2010 *      |          |
| <i>(thousands of dollars, unless otherwise stated)</i>                         |                             |             |          |
| Oil and gas sales  | \$ 25,586                   | \$ 23,265   | 10%      |
| Revenue, net of royalties  | \$ 23,283                   | \$ 19,871   | 17%      |
| Funds from operations  | \$ 10,868                   | \$ 10,435   | 4%       |
| Funds from operations per share (basic and diluted)                            | \$ 0.06                     | \$ 0.06     | -        |
| Net income (loss) before effect of impairment                                  | \$ (3,681)                  | \$ 256      | (1538%)  |
| Net income (loss) per share before effect of impairment (basic and diluted)    | \$ (0.02)                   | \$ -        | (100%)   |
| Net loss   | \$ (3,681)                  | \$ (44,444) | 92%      |
| Net loss per share (basic and diluted)   | \$ (0.02)                   | \$ (0.27)   | 92%      |
| Capital expenditures, including acquisitions net of dispositions               | \$ 42,354                   | \$ 33,227   | 27%      |
| Bank loans plus cash working capital deficiency                                | \$ 102,971                  | \$ 65,753   | 57%      |
| Convertible debentures   | \$ 43,679                   | \$ -        | 100%     |
| Shareholders' equity   | \$ 178,628                  | \$ 258,292  | (31%)    |
| Average shares outstanding <i>(thousands)</i>                                  |                             |             |          |
| Basic  | 172,504                     | 163,811     | 5%       |
| Diluted  | 172,504                     | 163,811     | 5%       |
| Ending shares outstanding <i>(thousands)</i>                                   | 172,545                     | 172,400     | -        |
| Average daily sales  |                             |             |          |
| Natural gas <i>(Mcf)</i>   | 33,931                      | 35,221      | (4%)     |
| Oil <i>(bpd)</i>   | 1,372                       | 345         | 298%     |
| NGL <i>(bpd)</i>   | 699                         | 785         | (11%)    |
| Barrels of oil equivalent <i>(BOED)</i>  | 7,726                       | 7,000       | 10%      |
| Average prices   |                             |             |          |
| Natural gas <i>(\$/Mcf)</i>  | \$ 3.58                     | \$ 5.22     | (31%)    |
| Oil <i>(\$/bbl)</i>  | \$ 84.71                    | \$ 75.47    | 12%      |
| NGL <i>(\$/bbl)</i>  | \$ 65.97                    | \$ 56.68    | 16%      |
| Barrels of oil equivalent <i>(\$/BOE)**</i>                                    | \$ 36.80                    | \$ 36.93    | -        |
| Realized loss on derivative contracts <i>(\$/BOE)</i>                          | \$ (0.57)                   | \$ -        | (100%)   |
| Royalties <i>(\$/BOE)</i>  | \$ 3.31                     | \$ 5.39     | (39%)    |
| Operating costs <i>(\$/BOE)</i>  | \$ 10.96                    | \$ 10.91    | -        |
| Operating netback <i>(\$/BOE)</i>  | \$ 21.96                    | \$ 20.63    | 6%       |
| General and administrative, excluding stock-based compensation <i>(\$/BOE)</i> | \$ 3.80                     | \$ 3.05     | 25%      |
| Wells drilled <i>(gross)</i>   | 15                          | 26          | (42%)    |

\* 2010 results have been restated to conform with International Financial Reporting Standards.

\*\* Includes royalty and other income classified with oil and gas sales, but excludes realized and unrealized losses on derivative contracts.

## OPERATIONS:

**Cardium Horizontal Oil.** In the first quarter of 2011, 15 gross (11.3 net revenue) Cardium horizontal oil wells were drilled. To date in the second quarter of 2011, the Company has drilled 4 gross (2.5 net revenue) Cardium horizontal oil wells. From May 1, 2010 to May 16, 2011, the Company has placed 41 gross (29.2 net) wells on production. Cardium production was approximately 2,300 to 2,400 BOED (85% oil and NGL) as of May 16, 2011. Oil and NGL production for the three months ended March 31, 2011 was 2,071 bpd, up substantially from 1,130 bpd in the first quarter of 2010. Of this number, 1,372 bpd or 66% is crude oil production, compared to 345 bpd or 31% in the first quarter of 2010. The Company plans to drill 44 gross (32.7 net capital, 28.6 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 May 12, 2011                         | 41                   | 29.2       | 41                         | 29.2       |
| Estimated up to December 31, 2011          | 66                   | 44.0       | 66                         | 44.0       |

*"Net" is net revenue interest earned.*

The Company's Cardium prospective land inventory is 115 gross (68.3 net) sections, which has appreciated 4% since the last update on March 28, 2011. Approximately 85% of the Company's Cardium lands are in the oil prone fairway and the balance is in the gas prone fairway. Using geological mapping and offset production information, the Company has high-graded a location list to drill in the oil prone fairway. The list includes 188 gross (116.2 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, drilling by third parties offsetting Company lands and new land deals have increased the count by 4.5% since the March 28, 2011 press release. The Company does not include prospective locations from the gas prone fairway until natural gas prices improve. 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](http://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 go forward drill, complete, equip and tie-in costs for the Cardium horizontal program with water based fracture stimulation to be approximately \$2.6 million per well in the Garrington field and \$3.0 to \$3.2 million per well in other properties.

In the Garrington field, the Company has drilled 23 gross (17.0 net) Cardium horizontal wells to date, with 40 gross (26.6 net) locations remaining to be drilled. The Company's first well in Garrington came on-stream on May 1, 2010. Since then, the Company has grown its Garrington working interest production to 1,300 BOPD (1,470 BOED including solution gas and NGL).

The Company has recently completed its best performing well in the Garrington field. This 100% working interest well was fracture stimulated with a 19 stage gelled water frac and has flowed back 4,000 bbls of reservoir oil in its first seven days of production, at varying rates of 278 to 1,144 BOPD and at time of writing of this press release was flowing at 300 BOPD.

In Garrington, the Company is currently in the process of connecting all of its single well batteries and field satellites to its central 15-34 tank battery. The 100% owned facility will ultimately be connected by Plains Midstream Canada to the Rangeland Pipeline system. This facility is attracting third party volumes and so also represents an attractive source of processing fee income for the Company.

The Company will be conducting a reservoir simulation study to plan its waterflood for the Garrington field. The Company is planning to conduct a water injectivity test in the fourth quarter of 2011 and be in a position to inject water in 2012.

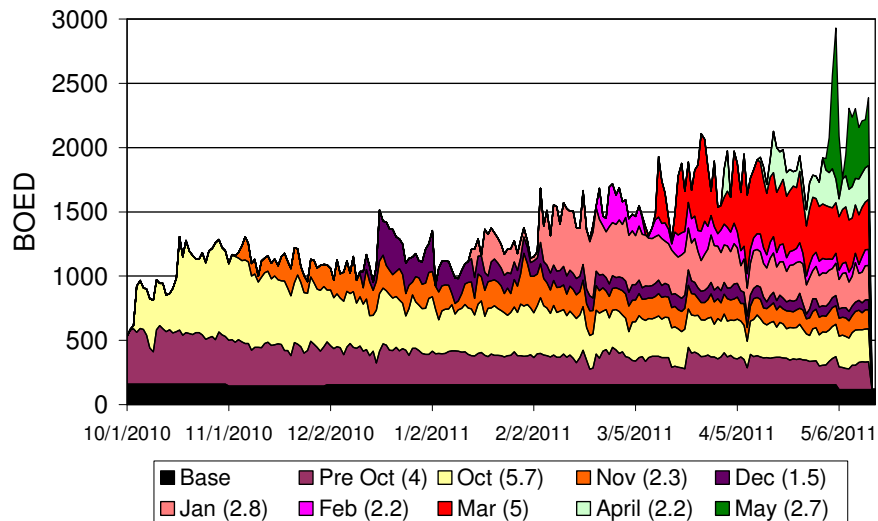
The Company has been primarily focused on drilling Cardium A sand horizontal wells. In the first quarter of 2011, the Company made a new discovery in a Cardium B sand with a horizontal well and is planning to pursue both the A and B sands in that particular area.

## PRODUCTION

For the quarter ended March 31, 2011, the Company averaged 7,726 BOED, with oil and NGL volumes representing 27% of total volumes. Oil and NGL production is 83% higher than the first quarter of 2010 due to increasing Cardium oil volumes. The Company had a very successful first quarter drilling and completing Cardium oil wells. The production impact from these wells is expected in the second quarter of 2011, with second quarter oil production estimated to be 35 to 40% higher than first quarter oil production.

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, net of dispositions and drilling incentive credits, were \$42.4 million in the first quarter of 2011 with \$38.9 million spent on drilling and completions before drilling incentive credits and \$7.1 million spent on facilities. This compares to capital expenditures of \$33.2 million in the first quarter of 2010.

The Company's funds from operations were \$10.9 million in the first quarter of 2011 compared to \$10.4 million in the first quarter of 2010. The Company's average crude oil and natural gas liquids sales price in the first quarter of 2011 was \$78.39 per barrel compared to \$62.43 per barrel in the first quarter of 2010. The Company realized a loss of \$0.4 million on WTI Canadian fixed price oil contracts in the first quarter of 2011, which negatively impacted funds from operations. WTI oil prices averaged US\$94.10 per barrel in the first quarter of 2011 and are estimated to be higher in the second quarter based on prices to date. The Company has entered into fixed price oil swaps for 2011 and 2012. The WTI Canadian prices are on these contracts range between \$88.45 per bbl to \$107.00 per bbl. The Company's average natural gas sales price was \$3.58 per Mcf in the first quarter of 2011 compared to \$5.22 per Mcf in first quarter of 2010. The Company's operating netback was \$21.96 per BOE in the first quarter of 2011 compared to \$20.63 per BOE in the first quarter of 2010. The increase in the operating netback was primarily due to the increase in oil and NGL prices and volumes.

|  | Average<br>wellhead<br>natural gas<br>price<br>(\$/Mcf) | Revenue<br>(\$/BOE) | Net operating<br>income<br>(\$/BOE) | Cash flow<br>(\$/BOE) |
|--|---|---------------------|-------------------------------------|-----------------------|
| 2009 *   | 3.95  | 27.74               | 15.07                               | 11.26                 |
| 2010 *   | 3.96  | 31.31               | 17.44                               | 13.22                 |
| First quarter of 2011                            | 3.58  | 36.80               | 21.96                               | 15.63                 |
| 2011 estimate                                    |   |                     |                                     |                       |
| (\$87 to \$105 WTI** plus oil hedge<br>program)  | 3.65**  | 40.00 to 42.00      | 26.00 to 28.00                      | 19.00 to 21.00        |
| First quarter of 2012 estimate                   |   |                     |                                     |                       |
| (\$100 to \$110 WTI** plus oil hedge<br>program) | 4.00**  | 50.00 to 52.00      | 36.00 to 38.00                      | 28.00 to 30.00        |

\* 2009 results have not been restated to conform with International Financial Reporting Standards. 2010 results have been restated to conform with International Financial Reporting Standards

\*\* estimate

As the Company increases its oil production, its revenue per BOE, net operating income per BOE and cash flow per BOE should increase and the Company expects to reposition itself to achieve profitability by 2012. Operating expenses in 2011 were \$10.96 per BOE, which was 6% lower than fourth quarter 2010 due to one time adjustments recorded in the fourth quarter of 2010. Operating expenses continue to be affected by start-up costs associated with the new Cardium production.

## 2011 CAPITAL PROGRAM

The Company's Board of Directors has approved an increase in the Company's capital program from \$75 million to \$115 million. Associated production guidance with this capital program is 7,500 to 8,000 BOED (33% Oil and NGL). In 2011, the Company estimates it could drill up to 44 gross (28.6 net) Cardium horizontal oil wells, of which 19 gross (13.8 net) have been drilled to date.

On May 13, 2011, the Company entered into an agreement with its lenders to renew its credit facilities and increase the total facilities to \$135 million, subject to execution of customary documentation and normal closing conditions.

## COMMODITY CONTRACTS

As part of its price management strategy, the Company has entered into fixed price swap contracts based on the NYMEX crude oil price in Canadian dollars. The average of those contracts for volume and price are summarized below:

| <i>Period</i>                        | <i>Weighted<br/>average volume<br/>(bbls)</i> | <i>Weighted average<br/>Canadian WTI<br/>(\$/bbl)</i> |
|--------------------------------------|---|---|
| April 1, 2011 to June 30, 2011       | 1,168   | 90.97   |
| July 1, 2011 to September 30, 2011   | 1,500   | 94.16   |
| October 1, 2011 to December 31, 2011 | 1,500   | 94.18   |
| January 1, 2012 to March 31, 2012    | 1,500   | 104.63  |
| April 1, 2012 to December 31, 2012   | 1,000   | 103.93  |

The business reasons for hedging are to protect the Company's capital program and support its bank borrowing base. Hedging oil at current prices achieves those objectives. As the Company continues to grow its oil production, it will evaluate the merits of additional commodity hedging as part of a price management strategy.

## OUTLOOK

Oil prices continue to remain strong, but volatile, due to increasing demand and ongoing geopolitical events in the world. 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 Canadian oil prices of \$100 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.

Second quarter oil production is estimated to be 35 to 40% higher than first quarter oil production. The Company's goal is to grow its oil production to achieve 50% of total production from oil and NGL by sometime in 2012. By the end of 2011, the Company estimates it will have 44 net Cardium horizontal wells on production, up 50% from today. The Company has increased its Cardium development drilling inventory by 36% since December 31, 2010 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 believes the results from the winter drilling program will help to peel the natural gas label off the Company's stock price and reward the shareholders with more of an oil company evaluation. As the Company grows its oil production in each quarter of 2011, the impact that this higher priced commodity will have on its cash flow is expected to be significant.

The Company is planning to commence its summer drilling program with four drilling rigs when ground conditions permit.

The Company invites its shareholders to attend the annual meeting on May 16, 2011 at the Metropolitan Centre in Calgary at 2:00 pm MDT and encourages anyone interested in further details on the Company to visit the Company's website at [www.andersonenergy.ca](http://www.andersonenergy.ca).

Brian H. Dau  
President & Chief Executive Officer  
May 16, 2011

## Management's Discussion and Analysis

FOR THE THREE MONTHS ENDED MARCH 31, 2011 AND 2010

The following discussion and analysis of financial results should be read in conjunction with the unaudited interim consolidated financial statements of Anderson Energy Ltd. ("Anderson Energy" or the "Company") for the three months ended March 31, 2011 and the audited consolidated financial statements and management's discussion and analysis of Anderson Energy for the years ended December 31, 2010 and 2009 and is based on information available as of May 13, 2011.

The following information is based on the interim consolidated financial statements of the Company at March 31, 2011, as prepared by management. The financial data included in this interim MD&A is in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB") and interpretations of the International Financial Reporting Interpretations Committee ("IFRIC") that are expected to be effective or available for early adoption by the Company as at December 31, 2011, the date of the Company's first annual reporting under IFRS. The effective date of the transition to IFRS was January 1, 2010. The transition to IFRS has been reflected by restating previously reported financial statements for 2010. This is the first time that the Company has prepared financial information under IFRS. Previously, the Company's financial statements were prepared under Canadian generally accepted accounting principles ("CGAAP"). The adoption of IFRS does not impact the underlying economics of the Company's operations or its cash flows. Note 17 to the interim consolidated financial statements contains a detailed description of the Company's adoption of IFRS, including a reconciliation of the consolidated financial statements previously prepared under CGAAP to those under IFRS.

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 including decommissioning 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 IFRS or CGAAP and therefore are referred to as non-GAAP measures.

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

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

## REVIEW OF FINANCIAL RESULTS

*Overview.* For the three months ended March 31, 2011, funds from operations were \$10.9 million, up 17% from the fourth quarter of 2010 as a result of the Company's refocus on Cardium light oil drilling. Sales volumes for the three months ended March 31, 2011 averaged 7,726 BOED, 6% lower than the fourth quarter of 2010. Oil and NGL production was 2,071 bpd in the first quarter of 2011, up 14% from the fourth quarter of 2010.

Capital expenditures, net of dispositions, were \$42.4 million for the three months ended March 31, 2011. During the first quarter of 2011, the Company drilled 15 gross (13.3 net) Cardium oil wells with a 100% success rate. The Company tied in 14 gross (11.3 net) Cardium oil wells and one gross (0.8 net) gas wells in the first three months of 2011. The Company has tied in an additional seven gross (4.5 net) Cardium oil wells to date in the second quarter of 2011.

Bank loans plus cash working capital deficiency was \$103.0 million at March 31, 2011, \$31.5 million higher than at December 31, 2010 as a result of increased capital spending during the three months ended March 31, 2011. The Company's board of directors has approved an increase in the Company's 2011 capital program from \$75 million to \$115 million. Associated production guidance with this expanded capital program is 7,500 to 8,000 BOED. In 2011, the Company estimates it could drill up to 44 gross (28.6 net revenue) Cardium horizontal oil wells, of which 19 gross (13.8 net revenue) have been drilled to date in 2011.

*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 represents 57% of total revenue in the first quarter of 2011, up 9% from the fourth quarter of 2010.

Gas sales volumes for the three months ended March 31, 2011 decreased to 33.9 MMcf from 38.5 MMcf in the fourth quarter of 2010. Gas sales volumes decreased 4% from the first quarter of 2010. The decrease is a result of the Company's focus on oil prospects in conjunction with natural declines in gas production. The Company suspended its shallow gas drilling program after the first quarter of 2010 until prices improve.

Oil sales for the three months ended March 31, 2011 averaged 1,372 bpd compared to 992 bpd in the fourth quarter of 2010 and 345 bpd for the first quarter of 2010. The increase in the 2011 volumes is due to 14 gross (11.3 net) Cardium oil wells brought on-stream in the quarter.

Natural gas liquids sales for the three months ended March 31, 2011 averaged 699 bpd compared to 823 bpd in the fourth quarter of 2010 and 785 bpd for the first quarter of 2010. Natural gas liquids volumes were affected by natural production declines, consistent with declines in gas production.

The following tables outline production revenue, volumes and average sales prices for the period ended March 31, 2011 and 2010.

## OIL AND NATURAL GAS REVENUE

| (thousands of dollars)                    | Three months ended March 31 |           |
|---|-----------------------------|-----------|
|   | 2011                        | 2010      |
| Natural gas                               | \$ 10,920                   | \$ 15,259 |
| Gain on fixed price natural gas contracts | -                           | 1,302     |
| Total natural gas                         | 10,920                      | 16,561    |
| Oil <sup>(1)</sup>                        | 10,463                      | 2,346     |
| NGL                                       | 4,149                       | 4,003     |
| Royalty and other                         | 54                          | 355       |
| Total revenue <sup>(1)</sup>              | \$ 25,586                   | \$ 23,265 |

(1) Excludes the realized loss and unrealized loss on derivative contracts of \$0.4 million and \$2.8 million respectively during the three months ended March 31, 2011 (March 31, 2010 - \$Nil).

## PRODUCTION

|                   | Three months ended March 31 |        |
|-------------------|-----------------------------|--------|
|                   | 2011                        | 2010   |
| Natural gas (Mcf) | 33,931                      | 35,221 |
| Oil (bpd)         | 1,372                       | 345    |
| NGL (bpd)         | 699                         | 785    |
| Total (BOED)      | 7,726                       | 7,000  |

## PRICES

|                                     | Three months ended March 31 |          |
|-------------------------------------|-----------------------------|----------|
|                                     | 2011                        | 2010     |
| Natural gas (\$/Mcf) <sup>(1)</sup> | \$ 3.58                     | \$ 5.22  |
| Oil (\$/bbl) <sup>(2)</sup>         | 84.71                       | 75.47    |
| NGL (\$/bbl)                        | 65.97                       | 56.68    |
| Total (\$/BOE) <sup>(2)(3)</sup>    | \$ 36.80                    | \$ 36.93 |

(1) Includes gain on fixed price natural gas contracts in 2010.

(2) Excludes the realized loss and unrealized loss on derivative contracts of \$0.4 million and \$2.8 million respectively during the three months ended March 31, 2011 (March 31, 2010 - \$Nil).

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

Anderson Energy's average natural gas sales price was \$3.58 per Mcf for the three months ended March 31, 2011, 3% higher than the fourth quarter of 2010 price of \$3.48 per Mcf and 31% lower than the first quarter of 2010 price of \$5.22 per Mcf. The first quarter of 2010 included gains on fixed price natural gas contracts. The price without the gains was \$4.81 per Mcf. Gas prices are significantly affected by increased supply and lower industrial consumption of natural gas in the United States and have remained low since the second quarter of 2010. The oil price in 2011 does not include a realized loss on derivative contracts of \$0.4 million. The realized oil price including this loss was \$81.47 per barrel for the first quarter of 2011 compared to \$76.18 per barrel in the fourth quarter of 2010.

**Commodity Contracts.** At March 31, 2011 the following derivative contracts were outstanding and recorded at estimated fair value:

| Type of Contract <sup>(1)</sup> | Commodity | Volume         | Weighted Average Fixed Price (NYMEX Canadian \$) | Remaining Period              |
|---------------------------------|-----------|----------------|--|-------------------------------|
| Financial swap                  | Crude oil | 1,000 bbls/day | \$ 88.45/bbl                                     | April 1, 2011 to Dec 31, 2011 |
| Financial swap                  | Crude oil | 500 bbls/day   | \$ 103.10/bbl                                    | Jan 1, 2012 to Dec 31, 2012   |

(1) Swap indicates fixed price payable to Anderson in exchange for floating price payable to counterparty.

In 2011, these contracts had the following impact on the consolidated statements of operations and comprehensive loss:

| (thousands of dollars)                  | Three months ended March 31, |      |
|---|------------------------------|------|
|   | 2011                         | 2010 |
| Realized loss on derivative contracts   | \$ (400)                     | \$ - |
| Unrealized loss on derivative contracts | (2,849)                      | -    |
|   | \$ (3,249)                   | \$ - |

In April 2011, the Company entered into the following fixed price swaps:

| Type of Contract <sup>(1)</sup> | Commodity | Volume       | Weighted Average Fixed Price (NYMEX Canadian \$) | Period                        |
|---------------------------------|-----------|--------------|--|-------------------------------|
| Financial swap                  | Crude oil | 250 bbls/day | \$ 106.00/bbl                                    | May 1, 2011 to Dec 31, 2011   |
| Financial swap                  | Crude oil | 250 bbls/day | \$ 105.15/bbl                                    | July 1, 2011 to Sept 30, 2011 |
| Financial swap                  | Crude oil | 250 bbls/day | \$ 105.30/bbl                                    | Oct 1, 2011 to Dec 31, 2011   |
| Financial swap                  | Crude oil | 500 bbls/day | \$ 106.04/bbl                                    | Jan 1, 2012 to Mar 31, 2012   |
| Financial swap                  | Crude oil | 500 bbls/day | \$ 104.75/bbl                                    | Jan 1, 2012 to Dec 31, 2012   |

(1) Swap indicates fixed price payable to Anderson in exchange for floating price payable to counterparty. As these April contracts were entered into subsequent to March 31, 2011, they have not been marked to market in the interim consolidated financial statements.

**Royalties.** Royalties were 9.0% of revenue for the three months ended March 31, 2011 compared to 9.4% for the fourth quarter of 2010 and 14.6% for the three months ended March 31, 2010. During the first quarter of 2011, the Crown royalty rate declined by 35 percent compared to the same period in 2010. This decrease is partly due to declining natural gas prices. Natural gas prices declined 25 percent from the first quarter of 2010 compared to the first quarter of 2011. The remaining difference is due to new production from Crown lands coming on-stream at five percent Crown royalty rates.

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. Under, the Alberta government's New Royalty Framework, 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, for horizontal oil wells, 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.

|                       | <i>Three months ended March 31</i> |             |
|-----------------------|------------------------------------|-------------|
|                       | <i>2011</i>                        | <i>2010</i> |
| Gross Crown royalties | 9.7%                               | 14.9%       |
| Gas cost allowance    | (6.9%)                             | (6.8%)      |
| Other royalties       | 6.2%                               | 6.5%        |
| Total royalties       | 9.0%                               | 14.6%       |
| Royalties (\$/BOE)    | \$ 3.31                            | \$ 5.39     |

**Operating Expenses.** Operating expenses were \$10.96 per BOE for the three months ended March 31, 2011 compared to \$11.62 per BOE in the last quarter of 2010 and \$10.91 per BOE in the first quarter of 2010. Operating expenses in the first quarter of 2011 were lower than the fourth quarter of 2010 as that quarter was impacted by some one time costs as well as reclassification of co-gen power credits. In the first quarter of 2011, the Company continues to incur start-up costs on its new Cardium oil production that are largely related to the use of testers until the new wells can be tied in.

## OPERATING NETBACK

|                                       | <i>Three months ended March 31</i> |             |
|---------------------------------------|------------------------------------|-------------|
|                                       | <i>2011</i>                        | <i>2010</i> |
| <i>(thousands of dollars)</i>         |                                    |             |
| Revenue <sup>(1)</sup>                | \$ 25,586                          | \$ 23,265   |
| Realized loss on derivative contracts | (400)                              | -           |
| Royalties                             | (2,303)                            | (3,394)     |
| Operating expenses                    | (7,623)                            | (6,876)     |
|                                       | \$ 15,260                          | \$ 12,995   |
| Sales (MBOE)                          | 695.4                              | 630.0       |
| Per BOE                               |                                    |             |
| Revenue <sup>(1)</sup>                | \$ 36.80                           | \$ 36.93    |
| Realized loss on derivative contracts | (0.57)                             | -           |
| Royalties                             | (3.31)                             | (5.39)      |
| Operating expenses                    | (10.96)                            | (10.91)     |
|                                       | \$ 21.96                           | \$ 20.63    |

*(1) Includes royalty and other income classified with oil and gas sales. Excludes unrealized loss on derivative contracts of \$2.8 million pertaining to fixed price crude oil swaps recorded in the first quarter of 2011.*

**General and Administrative Expenses.** General and administrative expenses excluding stock-based compensation were \$2.6 million or \$3.80 per BOE for the three months ended March 31, 2011 compared to \$2.4 million or \$3.18 per BOE in the fourth quarter of 2010 and \$1.9 million or \$3.05 per BOE for the three months ended March 31, 2010. General and administrative expenses increased overall in the first quarter of 2011 and the fourth quarter of 2010, as compared to the first quarter of 2010, due to higher costs associated with employee bonus programs. Under IFRS, general and administrative expenses are shown inclusive of share-based payments on the consolidated statement of operations and comprehensive loss. IFRS also requires that the capitalization of general and administrative costs be limited to directly attributable costs. Under CGAAP, a reasonable allocation of general and administrative costs to

property, plant and equipment was acceptable. As a result of the change in the capitalization criteria, the Company increased its general and administrative costs by \$0.2 million for the three months ended March 31, 2010 as well as the three months ended December 31, 2010. The Company will have modestly higher general and administrative expenses in the future due to the adoption of IFRS.

| <i>(thousands of dollars)</i>                     | <i>Three months ended March 31,</i> |                                  |
|---|-------------------------------------|----------------------------------|
|   | <i>2011</i>                         | <i>2010</i><br><i>(restated)</i> |
| General and administrative (gross)                | \$ 4,127                            | \$ 3,026                         |
| Overhead recoveries                               | (353)                               | (447)                            |
| Capitalized                                       | <u>(1,132)</u>                      | <u>(660)</u>                     |
| General and administrative (cash)                 | \$ 2,642                            | \$ 1,919                         |
| Net stock-based compensation                      | <u>234</u>                          | <u>193</u>                       |
| <u>General and administrative</u>                 | <u>\$ 2,876</u>                     | <u>\$ 2,112</u>                  |
| General and administrative (cash) <i>(\$/BOE)</i> | \$ 3.80                             | \$ 3.05                          |
| <u>% Capitalized</u>                              | <u>27%</u>                          | <u>22%</u>                       |

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 option plans using the fair value method of accounting. Stock-based compensation expense was \$0.4 million for the first quarter of 2011 (\$0.2 million net of amounts capitalized) compared to \$0.3 million (\$0.2 million net of amounts capitalized) in the first quarter of 2010. Under IFRS, the calculation of stock-based compensation is the same as it was under CGAAP, however, the recognition of the expense is different. Under IFRS, the expense is recognized over the individual vesting periods for the graded vesting awards, resulting in more expense at the beginning of the recognition period, when compared to CGAAP, where the Company recognized the expense on a straight-line basis through the date of full vesting. As a result of the change to IFRS, stock-based compensation expense decreased in the three months ended March 31, 2010 by \$79,000 (\$31,000 net of amounts capitalized). On January 1, 2010, the transition date to IFRS, the Company revalued its unvested stock options and recognized an additional \$0.2 million in stock-based compensation which was recorded against opening retained earnings.

**Finance Expenses.** Under IFRS, finance expenses include accretion on decommissioning obligations, accretion and interest on convertible debentures, as well as interest on bank loans. Previously under CGAAP, accretion on decommissioning obligations was included with depletion, depreciation and accretion. Finance expenses were \$2.4 million for the first quarter of 2011, compared to \$1.5 million in the fourth quarter of 2010 and \$1.1 million in the first quarter of 2010. The increase in finance expenses is the result of higher interest and accretion on the convertible debentures which were issued on December 31, 2010, combined with higher interest rates and higher average bank loans. Bank loans, were \$59.2 million at March 31, 2011 compared to \$52.7 million at December 31, 2010 and \$38.8 million at March 31, 2010. The average effective interest rate on outstanding bank loans was 6.1% for the three months ended March 31, 2011 compared to 4.5% for the three months ended March 31, 2010.

| <i>(thousands of dollars)</i>                    | <i>Three months ended March 31,</i> |                                  |
|--|-------------------------------------|----------------------------------|
|  | <i>2011</i>                         | <i>2010</i><br><i>(restated)</i> |
| Interest and accretion on convertible debentures | \$ 1,157                            | \$ -                             |
| Interest expense on credit facilities            | 835                                 | 699                              |
| Accretion on decommissioning obligations         | 417                                 | 403                              |
| Finance expenses                                 | <u>\$ 2,409</u>                     | <u>\$ 1,102</u>                  |

**Depletion and depreciation.** Depletion and depreciation was \$17.77 per BOE or \$12.4 million for the first quarter of 2011 compared to \$17.45 per BOE, or \$13.2 million in the fourth quarter of 2010 and \$16.42 per BOE or \$10.3 million in the first quarter of 2010. Under IFRS, the Company calculates depletion and depreciation expense on proved plus probable reserves on an area basis. Previously, under CGAAP, depletion and depreciation was calculated based on proved reserves only on the full cost pool. Going forward, the Company's depletion and depreciation will be lower under IFRS than was previously reported under CGAAP due to both this change in methodology and the impairment write-downs taken under IFRS.

**Impairment of property, plant and equipment.** Under CGAAP, impairment of property, plant and equipment was assessed on the basis of an asset's estimated undiscounted future cash flows compared with the asset's carrying amount and if impairment was indicated, discounted cash flows were prepared to quantify the amount of the impairment. Under IFRS, impairment is assessed based on discounted cash flows compared with the asset's carrying amount to determine the recoverable amount and measure the amount of the impairment. In addition, under IFRS, the Company is required to perform its test at a cash generating unit ("CGU") level, which is the smallest identifiable grouping of assets that generates largely independent cash inflows. CGAAP impairment was based on undiscounted cash flows on a full cost centre basis. There is no requirement under IFRS to test for impairment at least annually as was done under CGAAP. Instead, IFRS requires that when there are indicators of impairment present, that an impairment test be performed. In addition, under IFRS, the Company must evaluate whether there are any changes in circumstances that would support an impairment reversal, which was not allowable under CGAAP. This may result in recoveries of previous impairments in future periods, net of depletion and depreciation.

At January 1, 2010, the effective transition date to IFRS, the Company elected to use the IFRS 1 deemed cost exemption whereby the costs under CGAAP were allocated to CGUs based on reserves volumes and then tested for impairment. As a result, the Company recognized an impairment of \$67.2 million at January 1, 2010 in the Shallow Gas CGU with a corresponding reduction in opening retained earnings. For the three months ended March 31, 2010 and the year ended December 31, 2010 the Company recognized additional impairments of \$59.5 million and \$153.2 million respectively with a corresponding reduction in property, plant and equipment for the Shallow Gas, Deep Gas and Non-core CGUs due to declines in the forward curve for natural gas prices. There were no indicators of impairment during the three months ended March 31, 2011, thus the Company did not test for impairment. In addition, there were no indicators of impairment reversal in the first quarter of 2011 as there were no increases to the natural gas forward price curves. No impairments have been recorded against the Company's Horizontal Oil CGU to date. Under CGAAP, no impairments were recognized in prior periods. The commodity

price forecasts published by the Company's independent reserves engineers at April 1, 2011 were as follows:

|               | <i>AECO Gas Price<br/>(\$Cdn/Mcf)</i> | <i>WTI Cushing<br/>(\$US/bbl)</i> | <i>Exchange rate<br/>(US\$/Cdn)</i> |
|---------------|---------------------------------------|-----------------------------------|-------------------------------------|
| 2011 Q2-Q4    | 4.08                                  | 105.00                            | 0.98                                |
| 2012          | 4.74                                  | 102.00                            | 0.98                                |
| 2013          | 5.31                                  | 100.00                            | 0.98                                |
| 2014          | 5.77                                  | 100.00                            | 0.98                                |
| 2015          | 6.22                                  | 100.00                            | 0.98                                |
| 2016          | 6.53                                  | 100.00                            | 0.98                                |
| 2017          | 6.76                                  | 101.36                            | 0.98                                |
| 2018          | 6.90                                  | 103.38                            | 0.98                                |
| 2019          | 7.06                                  | 105.45                            | 0.98                                |
| 2020          | 7.21                                  | 107.56                            | 0.98                                |
| Thereafter 2% |                                       |                                   |                                     |

**Decommissioning obligations.** The Company recorded an increase of \$1.0 million in decommissioning obligations in the first quarter of 2011 related to current activity and changes in estimates. The Company disposed of \$0.2 million in decommissioning obligations as part of a property disposition in the first quarter of 2011. Accretion expense was \$0.4 million for the first quarter of 2011 compared to \$0.4 million in the first quarter of 2010 and was included in finance expenses.

Decommissioning obligations (asset retirement obligations under CGAAP) are measured based on the estimated cost of decommissioning, discounted to their net present value upon initial recognition. Under CGAAP, asset retirement obligations were discounted at a credit adjusted risk free rate of eight to 10 percent. Under IFRS, the estimated cash flow to abandon and remediate the wells and facilities is considered to be risk adjusted already, therefore the decommissioning obligation is discounted at a risk free rate of one to four percent depending on the estimated timing of the future obligation. Under IFRS, decommissioning obligations are also required to be re-measured based on changes in estimates including discount rates. Accretion is lower under IFRS than under CGAAP as the discounted obligation is initially set up at a higher amount.

The IFRS 1 exemption was utilized for decommissioning obligations associated with oil and gas properties and the Company re-measured decommissioning obligations as at January 1, 2010 under IAS 37 with a corresponding adjustment to opening retained earnings. Upon transition to IFRS, this resulted in a \$13.8 million increase in the decommissioning obligations with a corresponding decrease in opening retained earnings.

**Income Taxes.** Anderson Energy is not currently taxable. The Company does not anticipate paying current income tax in 2011. The Company has approximately \$420 million in tax pools at March 31, 2011.

**Funds from Operations.** Funds from operations for the first quarter of 2011 were \$10.9 million (\$0.06 per share), a 17% increase over the \$9.3 million (\$0.05 per share) recorded in the fourth quarter of 2010 and 4% higher than the \$10.4 million (\$0.06 per share) recorded in the same

period of the prior year. The increase in funds from operations in 2011 is a result of the Company's focus on oil prospects, which generate more cash flow per BOE when compared to natural gas properties. As new crude oil production is brought on-stream at higher expected operating margins, funds from operation are expected to increase. The changes in funds from operations as reported under IFRS for the first and fourth quarters of 2010 relate to the decrease in the capitalized general and administrative costs of \$0.2 million in each respective quarter from what was previously reported under CGAAP.

| <i>(thousands of dollars)</i>   | <i>Three months ended March 31</i> |                            |
|---|------------------------------------|----------------------------|
|   | <i>2011</i>                        | <i>2010<br/>(restated)</i> |
| Cash from operating activities  | \$ 11,001                          | \$ 12,746                  |
| Changes in non-cash working capital<br>and decommissioning expenditures | <u>(133)</u>                       | <u>(2,311)</u>             |
| <b>Funds from operations</b>  | <b>\$ 10,868</b>                   | <b>\$ 10,435</b>           |

**Earnings (loss).** The Company reported a loss of \$3.7 million in the first quarter of 2011 compared to a loss of \$36.5 million for the three months ended December 31, 2010 and a loss of \$44.4 million for the first quarter of 2010. The loss in the first quarter of 2011 was negatively affected by the unrealized loss on derivative contracts of \$2.8 million. The loss was less than in previous quarters as there were no impairments recorded in 2011. In the first quarter of 2010, the Company had an impairment of property, plant and equipment of \$59.5 million, and in the fourth quarter of 2010, the Company recorded an additional impairment of \$42.2 million as a result of depressed forward price curves for natural gas properties. Previously under CGAAP, the Company did not have any impairments of its property, plant and equipment.

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>(thousands of dollars)</i>         | <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 \$42.4 million on capital expenditures, net of dispositions and drilling incentive credits in the first quarter of 2011. The breakdown of expenditures is shown below:

| <i>(thousands of dollars)</i>                          | <i>2011</i>      | <i>2010</i><br><i>(restated)</i> |
|--|------------------|----------------------------------|
| Land, geological and geophysical costs                 | \$ 289           | \$ 28                            |
| Acquisitions   | (2)              | 724                              |
| Proceeds on disposition                                | (5,200)          | (2,169)                          |
| Drilling, completion and recompletion                  | 38,898           | 17,044                           |
| Drilling incentive credits                             | 153              | (2,614)                          |
| Facilities and well equipment                          | 7,082            | 20,744                           |
| Capitalized G&A  | 1,132            | 660                              |
| Total finding, development & acquisition expenditures  | 42,352           | 34,417                           |
| Change in compressor and other inventory and equipment | -                | (1,199)                          |
| Office equipment and furniture                         | 2                | 9                                |
| <b>Total net cash capital expenditures</b>             | <b>\$ 42,354</b> | <b>\$ 33,227</b>                 |

As a result of adopting IFRS, previously reported capital expenditures have been restated to reflect the reporting of gains or losses on disposition of property, plant and equipment as well as changes to the capitalization criteria for general and administrative expenses. Under CGAAP, gains or losses on disposition of property, plant and equipment were only reported when the disposition resulted in more than a 20 percent change in the depletion rate. As a result of this requirement, the Company reported a gain of \$0.7 million during the three months ended March 31, 2010 with an increase in property, plant and equipment where the proceeds were originally recorded under CGAAP and a net increase to decommissioning obligations that were assumed as part of an asset exchange of \$0.2 million. As well, capitalized general and administrative expenses have decreased as a result of adoption of IFRS as previously discussed.

Drilling statistics are shown below:

|                         | <i>Three months ended March 31</i> |             |              |             |
|-------------------------|------------------------------------|-------------|--------------|-------------|
|                         | <i>2011</i>                        |             | <i>2010</i>  |             |
|                         | <i>Gross</i>                       | <i>Net</i>  | <i>Gross</i> | <i>Net</i>  |
| Gas                     | -                                  | -           | 19           | 16.0        |
| Oil                     | 15                                 | 13.3        | 3            | 2.3         |
| Dry                     | -                                  | -           | 4            | 2.8         |
| <b>Total</b>            | <b>15</b>                          | <b>13.3</b> | <b>26</b>    | <b>21.1</b> |
| <b>Success rate (%)</b> | <b>100%</b>                        | <b>100%</b> | <b>85%</b>   | <b>87%</b>  |

During the first quarter of 2011, the Company drilled 15 gross (13.3 net capital) Cardium horizontal light oil wells. In addition, the Company brought 14 gross (11.3 net revenue) Cardium horizontal light wells on-stream and tied in one gross (0.8 net revenue) natural gas wells. Approximately \$7.1 million was spent on facilities and well equipment.

Drilling incentive 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 were earned through drilling in the fourth quarter of 2009 but 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, in the first quarter of 2011, the Company reduced its estimate of drilling incentive credits that it will be entitled to by \$0.5 million to a total of \$4.5 million. The Company did receive \$0.3 million in proceeds on the sale of some of its surplus credits during the first quarter of 2011.

## SHARE INFORMATION

The Company's shares have been listed on the Toronto Stock Exchange since September 7, 2005 under the symbol "AXL". As of May 13, 2011, there were 172.5 million common shares outstanding, 11.3 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 the first quarter of 2011, 60,000 common shares (2010 – Nil) were issued under the employee stock option plan.

|                                   | <i>Three months ended March 31,</i> |                |
|-----------------------------------|-------------------------------------|----------------|
|                                   | <i>2011</i>                         | <i>2010</i>    |
| High                              | \$ 1.36                             | \$ 1.57        |
| Low                               | \$ 1.00                             | \$ 1.10        |
| Close                             | \$ 1.21                             | \$ 1.14        |
| Volume                            | 61,575,839                          | 43,643,072     |
| Shares outstanding at March 31    | 172,545,301                         | 172,400,401    |
| Market capitalization at March 31 | \$ 208,779,814                      | \$ 196,536,457 |

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 43.5 million common shares traded on these alternative exchanges in the three months ended March 31, 2011 (March 31, 2010 – 22.9 million). Including these exchanges, an average of 1.7 million common shares traded per day in the first quarter of 2011 (March 31, 2010 – 1.1 million), representing a turnover ratio of 61% (March 31, 2010 – 39%).

## LIQUIDITY AND CAPITAL RESOURCES

At March 31, 2011, the Company had bank loans of \$59.2, convertible debentures of \$50.0 million (principal) and a working capital deficiency of \$43.7 million, excluding the unrealized loss on derivative contracts. The working capital deficiency is due to accruals associated with the capital program.

On May 13, 2011, the Company agreed with its lenders to renew the credit facilities to July 12, 2012 at a total combined amount of \$135 million, subject to execution of customary documentation and normal closing conditions. The new facilities will consist of a \$100 million extendible revolving term credit facility, a \$10 million working capital credit facility and a \$25

million supplemental credit facility. If not extended, the extendible revolving term credit facility and working capital credit facility cease to revolve and all outstanding advances thereunder become repayable one year from the term date of July 12, 2012. The supplemental facility expires on July 12, 2012. Draws over \$10 million under the supplemental facility are subject to the consent of the bank syndicate at the time of the drawdown.

The Company has received approval from its board of directors to increase the capital budget for 2011 from \$75 million to \$115 million. 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 44 gross (32.7 net capital, 28.6 net revenue) Cardium oil wells in 2011, of which 19 gross (16.1 net capital, 13.8 net revenue) have been drilled to date in 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 March 31, 2011, the Company had total credit facilities of \$125 million and \$65.6 million of credit available under these facilities. 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. 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 in November 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 March 31, 2011. As noted under Liquidity and Capital Resources, these facilities were increased and extended to July 12, 2012 on May 13, 2011.
- *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 \$1.4 million for the remainder of 2011, and \$1.6 million in 2012.
- *Firm service transportation commitments* – The Company has entered into firm service transportation agreements for approximately 27 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 \$1.3 million for the remainder of 2011, \$1.4 million in 2012, \$0.9 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 third 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.

These obligations are described further in note 16 to the interim consolidated financial statements for the three months ended March 31, 2011.

#### INTERNATIONAL FINANCIAL REPORTING STANDARDS

The Company adopted IFRS effective January 1, 2011. As a result, the Company's financial results for the first quarter ended March 31, 2011 and comparative periods are reported under IFRS while selected historical data before 2010 continues to be reported under previous CGAAP. (Refer to note 17 of the interim consolidated financial statements for the Company's assessment of the impacts of the transition to IFRS).

## NEW AND PENDING ACCOUNTING STANDARDS

*IFRS 9 – Financial Instruments.* In November 2009, the IASB published IFRS 9 “Financial Instruments” which covers the classification and measurement of financial assets as part of its project to replace IAS 39 “Financial Instruments: Recognition and Measurement.” IFRS 9 uses a single approach to determine whether a financial asset is measured at amortized cost or fair value, replacing the multiple rules in IAS 39. The approach in IFRS 9 is based on how an entity managed its financial instruments in the context of its business model and the contractual cash flow characteristics of the financial assets. The new standard also requires a single impairment method to be used, replacing the multiple impairment methods in IAS 39.

In October 2010, additional requirements for classifying and measuring financial liabilities were added to IFRS 9. Under this guidance, entities have the option to recognize financial liabilities at fair value through profit or loss. If this option is elected, entities would be required to reverse the portion of the fair value change due to own credit risk out of profit or loss and recognize the change in other comprehensive income.

IFRS 9 will become effective for the Company on January 1, 2013. Early adoption is permitted and the standard is required to be applied retrospectively. The implementation of the issued standard is not expected to have a significant impact on the Company’s financial position or results.

*IAS 12 – Income Taxes.* IAS 12 “Income Taxes” was amended on December 20, 2010 to remove subjectivity in determining on which basis an entity measures the deferred tax relating to an asset. The amendment introduces a presumption that an entity will assess whether the carrying value of an asset will be recovered through the sale of the asset. The amendment to IAS 12 is effective for reporting periods beginning on or after January 1, 2012. The Company is currently evaluating the impact of this amendment to its financial statements.

## CONTROLS AND PROCEDURES

The Chief Executive Officer (“CEO”) and the Chief Financial Officer (“CFO”) have designed, or caused to be designed under their supervision, disclosure controls and procedures (“DC&P”) and internal controls over financial reporting (“ICOFR”) as defined in National Instrument 52-109 Certification of Disclosure in Issuer’s Annual and Interim Filings in order to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the financial statements for external purposes in accordance with IFRS.

The DC&P have been designed to provide reasonable assurance that material information relating to the Company is made known to the CEO and CFO by others and that information required to be disclosed by the Company in its annual filings, interim filings or other reports filed or submitted by the Company under securities legislation is recorded, processed, summarized and reported within the time periods specified in securities legislation. The Company’s CEO and CFO have concluded, based on their evaluation as of the end of the period covered by the interim filings, that the Company’s disclosure controls and procedures are effective to provide reasonable assurance that material information related to the issuer is made known to them by others within the Company.

The CEO and CFO are required to cause the Company to disclose any change in the Company's ICOFR that occurred during the most recent interim period that has materially affected, or is reasonably likely to materially affect, the Company's ICOFR. No changes in ICOFR were identified during such period that have materially affected or are reasonably likely to materially affect the Company's ICOFR. There were no changes to ICOFR as a result of the transition to IFRS

It should be noted a control system, including the Company's DC&P and ICOFR, no matter how well conceived or operated, can provide only reasonable, not absolute, assurance that the objective of the control system will be met and it should not be expected that DC&P and ICOFR will prevent all errors or fraud.

## **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 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.

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. On March 3, 2009, June 11, 2009 and June 25, 2009, the Government of Alberta announced amendments to the framework. 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.

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 50% to 40% for conventional oil and to 36% for natural gas.

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 115 gross (68.3 net) sections in the fairway and has identified an inventory of 188 gross (116.2 net) drill ready Cardium horizontal oil locations, of which 41 gross (29.2 net) have been drilled to date. 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 new annual production guidance for 2011 is 7,500 – 8,000 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 remain volatile, affecting funds from operations and earnings throughout 2009 and into 2011. Note that the quarterly table contains both IFRS and CGAAP numbers. Comparatives before 2010 have not been restated to reflect the changes in accounting policies as a result of adopting IFRS.

## SELECTED QUARTERLY INFORMATION

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

|  | <b>IFRS</b>    |                                     |                                     |                                     |
|--|----------------|-------------------------------------|-------------------------------------|-------------------------------------|
|  | <b>Q1 2011</b> | <b>Q4 2010</b><br><i>(restated)</i> | <b>Q3 2010</b><br><i>(restated)</i> | <b>Q2 2010</b><br><i>(restated)</i> |
| Oil and gas sales  | \$ 25,586      | \$ 23,946                           | \$ 18,928                           | \$ 20,318                           |
| Revenue, net of royalties  | \$ 23,283      | \$ 21,690                           | \$ 17,263                           | \$ 18,622                           |
| Funds from operations  | \$ 10,868      | \$ 9,283                            | \$ 7,876                            | \$ 8,923                            |
| Funds from operations per share                                  |                |                                     |                                     |                                     |
| Basic and diluted  | \$ 0.06        | \$ 0.05                             | \$ 0.05                             | \$ 0.05                             |
| Net loss before effect of impairment                             | \$ (3,681)     | \$ (4,865)                          | \$ (3,059)                          | \$ (2,449)                          |
| Net loss per share before effect of impairment                   |                |                                     |                                     |                                     |
| Basic and diluted  | \$ (0.02)      | \$ (0.03)                           | \$ (0.02)                           | \$ (0.01)                           |
| Net loss   | \$ (3,681)     | \$ (36,544)                         | \$ (39,031)                         | \$ (4,768)                          |
| Net loss per share, basic and diluted                            | \$ (0.02)      | \$ (0.21)                           | \$ (0.23)                           | \$ (0.03)                           |
| Capital expenditures, including acquisitions net of dispositions | \$ 42,354      | \$ 26,241                           | \$ 39,378                           | \$ 12,664                           |
| Cash from operating activities                                   | \$ 11,001      | \$ 10,489                           | \$ 8,287                            | \$ 8,811                            |
| Daily sales  |                |                                     |                                     |                                     |
| Natural gas ( <i>Mcf/d</i> )                                     | 33,931         | 38,479                              | 35,778                              | 38,998                              |
| Liquids ( <i>bpd</i> )   | 2,071          | 1,815                               | 1,329                               | 1,232                               |
| BOE ( <i>BOED</i> )  | 7,726          | 8,228                               | 7,292                               | 7,732                               |
| Average prices   |                |                                     |                                     |                                     |
| Natural gas ( <i>\$/Mcf</i> )                                    | \$ 3.58        | \$ 3.48                             | \$ 3.43                             | \$ 3.78                             |
| Liquids ( <i>\$/bbl</i> )  | \$ 78.39       | \$ 69.11                            | \$ 58.61                            | \$ 60.28                            |
| BOE ( <i>\$/BOE</i> )*   | \$ 36.80       | \$ 31.63                            | \$ 28.21                            | \$ 28.88                            |

|  | <b>IFRS</b>                         | <b>CGAAP</b>   |                |                |
|--|-------------------------------------|----------------|----------------|----------------|
|  | <b>Q1 2010</b><br><i>(restated)</i> | <b>Q4 2009</b> | <b>Q3 2009</b> | <b>Q2 2009</b> |
| Oil and gas sales  | \$ 23,265                           | \$ 20,439      | \$ 14,617      | \$ 17,508      |
| Revenue, net of royalties  | \$ 19,871                           | \$ 18,708      | \$ 13,813      | \$ 16,224      |
| Funds from operations  | \$ 10,435                           | \$ 9,151       | \$ 6,623       | \$ 6,692       |
| Funds from operations per share                                  |                                     |                |                |                |
| Basic and diluted  | \$ 0.06                             | \$ 0.06        | \$ 0.04        | \$ 0.06        |
| Net income (loss) before effect of impairment                    | \$ 256                              | \$ (6,457)     | \$ (9,432)     | \$ (10,410)    |
| Net income (loss) per share before effect of impairment          |                                     |                |                |                |
| Basic and diluted  | \$ -                                | \$ (0.04)      | \$ (0.06)      | \$ (0.09)      |
| Net loss   | \$ (44,444)                         | \$ (6,457)     | \$ (9,432)     | \$ (10,410)    |
| Net loss per share, basic and diluted                            | \$ (0.27)                           | \$ (0.04)      | \$ (0.06)      | \$ (0.09)      |
| Capital expenditures, including acquisitions net of dispositions | \$ 33,227                           | \$ 11,312      | \$ 6,571       | \$ 2,130       |
| Cash from operating activities                                   | \$ 12,746                           | \$ 5,361       | \$ 6,689       | \$ 2,472       |
| Daily sales  |                                     |                |                |                |
| Natural gas ( <i>Mcf/d</i> )                                     | 35,221                              | 34,938         | 36,282         | 40,495         |
| Liquids ( <i>bpd</i> )   | 1,130                               | 1,257          | 1,013          | 1,040          |
| BOE ( <i>BOED</i> )  | 7,000                               | 7,080          | 7,060          | 7,789          |
| Average prices   |                                     |                |                |                |
| Natural gas ( <i>\$/Mcf</i> )                                    | \$ 5.22                             | \$ 4.28        | \$ 2.81        | \$ 3.43        |
| Liquids ( <i>\$/bbl</i> )  | \$ 62.43                            | \$ 53.79       | \$ 53.84       | \$ 49.00       |
| BOE ( <i>\$/BOE</i> )*   | \$ 36.93                            | \$ 31.38       | \$ 22.50       | \$ 24.70       |

\* Includes royalty and other income classified with oil and gas sales and excludes realized and unrealized losses on derivative contracts.

## 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, operating and other 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](http://www.sedar.com)) and at Anderson Energy's website ([www.andersonenergy.ca](http://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 Statements of Financial Position

(Stated in thousands of dollars)  
(Unaudited)

|  | March 31,<br>2011 | December 31,<br>2010<br>(note 17) | January 1,<br>2010<br>(note 17) |
|--|-------------------|-----------------------------------|---------------------------------|
| <b>ASSETS</b>  |                   |                                   |                                 |
| Current assets:  |                   |                                   |                                 |
| Cash and cash equivalents  | \$ -              | \$ 4,024                          | \$ 1                            |
| Accounts receivables and accruals (note 5)                             | 18,581            | 20,998                            | 22,990                          |
| Prepaid expenses and deposits  | <u>2,807</u>      | <u>3,052</u>                      | <u>3,778</u>                    |
|  | 21,388            | 28,074                            | 26,769                          |
| Deferred tax asset   | 30,796            | 29,656                            | -                               |
| Property, plant and equipment (note 8)                                 | <u>351,999</u>    | <u>320,674</u>                    | <u>403,207</u>                  |
|  | <u>\$ 404,183</u> | <u>\$ 378,404</u>                 | <u>\$ 429,976</u>               |
| <b>LIABILITIES AND SHAREHOLDERS' EQUITY</b>                            |                   |                                   |                                 |
| Current liabilities:   |                   |                                   |                                 |
| Accounts payable and accruals  | \$ 65,112         | \$ 46,862                         | \$ 36,889                       |
| Current portion of unrealized loss on<br>derivative contracts (note 5) | <u>4,595</u>      | <u>1,918</u>                      | <u>-</u>                        |
|  | 69,707            | 48,780                            | 36,889                          |
| Bank loans (note 10)   | 59,247            | 52,719                            | 62,404                          |
| Convertible debentures (note 11)                                       | 43,679            | 43,460                            | -                               |
| Decommissioning obligations (note 12)                                  | 52,750            | 51,550                            | 47,657                          |
| Unrealized loss on derivative contracts (note 5)                       | 172               | -                                 | -                               |
| Deferred tax liability   | <u>-</u>          | <u>-</u>                          | <u>10,920</u>                   |
|  | 225,555           | 196,509                           | 157,870                         |
| Shareholders' equity:  |                   |                                   |                                 |
| Share capital (note 13)  | 426,998           | 426,925                           | 396,524                         |
| Equity component of convertible<br>debentures (note 11)                | 2,592             | 2,592                             | -                               |
| Contributed surplus  | 8,262             | 7,921                             | 6,338                           |
| Deficit  | <u>(259,224)</u>  | <u>(255,543)</u>                  | <u>(130,756)</u>                |
|  | 178,628           | 181,895                           | 272,106                         |
| Commitments (note 16)  |                   |                                   |                                 |
| Subsequent events (note 5 & 10)  |                   |                                   |                                 |
|  | <u>\$ 404,183</u> | <u>\$ 378,404</u>                 | <u>\$ 429,976</u>               |

See accompanying notes to the consolidated financial statements.

# ANDERSON ENERGY LTD.

## Consolidated Statements of Operations and Comprehensive Loss

THREE MONTHS ENDED MARCH 31, 2011 AND 2010

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

|  | 2011             | 2010<br>(note 17) |
|--|------------------|-------------------|
| Oil and gas sales                                    | \$ 25,586        | \$ 23,265         |
| Royalties  | <u>(2,303)</u>   | <u>(3,394)</u>    |
| Revenue, net of royalties                            | 23,283           | 19,871            |
| Realized loss on derivative contracts                | (400)            | -                 |
| Unrealized loss on derivative contracts              | (2,849)          | -                 |
| Gain on sale of property, plant and equipment        | <u>385</u>       | <u>673</u>        |
|  | 20,419           | 20,544            |
| <br>   |                  |                   |
| Operating expenses                                   | 7,623            | 6,876             |
| Depletion and depreciation                           | 12,355           | 10,344            |
| Impairment of property, plant and equipment (note 9) | -                | 59,540            |
| General and administrative expenses                  | <u>2,876</u>     | <u>2,112</u>      |
| <br>   |                  |                   |
| Loss from operating activities                       | (2,435)          | (58,328)          |
| <br>   |                  |                   |
| Finance income (note 6)                              | 23               | 58                |
| Finance expenses (note 6)                            | <u>(2,409)</u>   | <u>(1,102)</u>    |
| Net finance expenses                                 | (2,386)          | (1,044)           |
| <br>   |                  |                   |
| Loss before taxes                                    | (4,821)          | (59,372)          |
| Deferred income tax reduction                        | <u>(1,140)</u>   | <u>(14,928)</u>   |
| Loss and comprehensive loss for the period           | <u>(3,681)</u>   | <u>(44,444)</u>   |
| <br>   |                  |                   |
| Basic and diluted loss per share (note 14)           | <u>\$ (0.02)</u> | <u>\$ (0.27)</u>  |

See accompanying notes to the consolidated financial statements.

## ANDERSON ENERGY LTD.

### Consolidated Statements of Changes in Shareholders' Equity

(Stated in thousands of dollars, except number of common shares)  
(Unaudited)

|  | Number of<br>Common Shares | Share<br>capital | Equity<br>component of<br>convertible<br>debentures | Contributed<br>surplus | Deficit      | Total<br>shareholders'<br>equity |
|--|----------------------------|------------------|---|------------------------|--------------|----------------------------------|
| Balance at January 1, 2010 <i>(note 17)</i>    | 150,500,401 \$             | 396,524 \$       | - \$  | 6,338 \$               | (130,756) \$ | 272,106                          |
| Issued pursuant to prospectus <i>(note 15)</i> | 21,900,000                 | 31,755           | -   | -                      | -            | 31,755                           |
| Share issue costs, net of tax of \$0.5 million | -                          | (1,456)          | -   | -                      | -            | (1,456)                          |
| Share-based payments                           | -                          | -                | -   | 331                    | -            | 331                              |
| Loss for the period                            | -                          | -                | -   | -                      | (44,444)     | (44,444)                         |
| Balance at March 31, 2010 <i>(note 17)</i>     | 172,400,401                | 426,823          | -   | 6,669                  | (175,200)    | 258,292                          |

|                            |                |            |          |          |              |         |
|----------------------------|----------------|------------|----------|----------|--------------|---------|
| Balance at January 1, 2011 | 172,485,301    | 426,925    | 2,592    | 7,921    | (255,543)    | 181,895 |
| Share-based payments       | -              | -          | -        | 366      | -            | 366     |
| Options exercised          | 60,000         | 73         | -        | (25)     | -            | 48      |
| Loss for the period        | -              | -          | -        | -        | (3,681)      | (3,681) |
| Balance at March 31, 2011  | 172,545,301 \$ | 426,998 \$ | 2,592 \$ | 8,262 \$ | (259,224) \$ | 178,628 |

See accompanying notes to the consolidated financial statements.

# ANDERSON ENERGY LTD.

## Consolidated Statements of Cash Flows

THREE MONTHS ENDED MARCH 31, 2011 AND 2010

(Stated in thousands of dollars)  
(Unaudited)

|  | 2011            | 2010<br>(note 17) |
|--|-----------------|-------------------|
| <b>CASH PROVIDED BY (USED IN) OPERATIONS</b>             |                 |                   |
| Loss for the period                                      | \$ (3,681)      | \$ (44,444)       |
| Adjustments for:   |                 |                   |
| Depletion and depreciation                               | 12,355          | 10,344            |
| Unrealized loss on derivative contracts                  | 2,849           | -                 |
| Impairment losses on property, plant and equipment       | -               | 59,540            |
| Deferred income tax reduction                            | (1,140)         | (14,928)          |
| Gain on sale of property, plant and equipment            | (385)           | (673)             |
| Stock-based compensation                                 | 234             | 193               |
| Accretion on decommissioning obligations                 | 417             | 403               |
| Accretion on convertible debentures                      | 219             | -                 |
| Decommissioning expenditures                             | (26)            | (229)             |
| Changes in non-cash working capital (note 7)             | <u>159</u>      | <u>2,540</u>      |
|  | 11,001          | 12,746            |
| <b>FINANCING</b>   |                 |                   |
| Increase (decrease) in bank loans                        | 6,528           | (23,579)          |
| Proceeds from issue of share capital, net of issue costs | -               | 29,792            |
| Proceeds from exercise of stock options                  | 48              | -                 |
| Changes in non-cash working capital (note 7)             | <u>(294)</u>    | <u>260</u>        |
|  | 6,282           | 6,473             |
| <b>INVESTING</b>   |                 |                   |
| Property, plant and equipment expenditures               | (47,554)        | (35,396)          |
| Proceeds from sale of property, plant and equipment      | 5,200           | 2,169             |
| Changes in non-cash working capital (note 7)             | <u>21,047</u>   | <u>14,008</u>     |
|  | <u>(21,307)</u> | <u>(19,219)</u>   |
| Decrease in cash and cash equivalents                    | (4,024)         | -                 |
| Cash and cash equivalents, beginning of period           | <u>4,024</u>    | <u>1</u>          |
| Cash, end of period                                      | \$ -            | \$ 1              |
| <hr/>  |                 |                   |
| Interest received in cash                                | \$ 23           | \$ 56             |
| Interest paid in cash                                    | \$ (517)        | \$ (262)          |

See accompanying notes to the consolidated financial statements.

# ANDERSON ENERGY LTD.

## Notes to the Interim Consolidated Financial Statements

THREE MONTHS ENDED MARCH 31, 2011 AND 2010

*(Tabular amounts in thousands of dollars, unless otherwise stated)  
(Unaudited)*

### 1. REPORTING ENTITY

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.

### 2. BASIS OF PREPARATION

*(a) Statement of compliance.* The interim consolidated financial statements have been prepared in accordance with International Accounting Standard 34 *Interim Financial Reporting*. These are the Company’s first International Financial Reporting Standards (“IFRS”) condensed interim consolidated financial statements for part of the period covered by the first IFRS annual financial statements and IFRS 1 *First-time Adoption of International Financial Reporting Standards* has been applied. They do not include all of the information required for full annual financial statements.

The Company’s significant accounting policies under IFRS are presented in note 3. These policies have been retrospectively and consistently applied except where specific exemptions permitted an alternative treatment upon transition to IFRS in accordance with IFRS 1. The impact of the new standards, including reconciliations presenting the change from previous GAAP to IFRS as at January 1, 2010, as at and for the three months ended March 31, 2010 and as at and for the year ended December 31, 2010, is presented in note 17.

The interim consolidated financial statements were authorized for issuance by the Board of Directors on May 13, 2011.

*(b) Basis of measurement.* The interim consolidated financial statements have been prepared on the historical cost basis except for derivative financial instruments, which are measured at fair value. The methods used to measure fair values are discussed in note 4.

*(c) Functional and presentation currency.* These interim consolidated financial statements are presented in Canadian dollars, which is the Company’s functional currency.

*(d) Use of estimates and judgements.* The preparation of financial statements in conformity with IFRS requires management to make judgements, estimates and assumptions that affect the application of accounting policies and the reported amounts of assets, liabilities, income and expenses. Actual results may differ from these estimates.

Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the year in which the estimates are revised and in any future years affected.

Information about significant areas of estimation uncertainty and critical judgements in applying accounting policies that have the most significant effect on the amounts recognized in the consolidated financial statements is included in the following notes:

- Note 5 – valuation of financial instruments
- Note 8 – valuation of property, plant and equipment
- Note 9 – impairment loss
- Note 12 – decommissioning obligations
- Note 13 – measurement of stock-based compensation

## 2. BASIS OF PREPARATION *(Continued)*

Reserve estimates impact a number of the areas referred to above, in particular, the valuation of property, plant and equipment and the calculation of depletion and depreciation.

## 3. SIGNIFICANT ACCOUNTING POLICIES

The accounting policies set out below have been applied consistently to all periods presented in these interim consolidated financial statements, and have been applied consistently by the Company and its subsidiaries.

### *(a) Basis of consolidation:*

*(i) Subsidiaries.* Subsidiaries are entities controlled by the Company. Control exists when the Company has the power to govern the financial and operating policies of an entity so as to obtain benefits from its activities. In assessing control, potential voting rights that currently are exercisable are taken into account. The financial statements of subsidiaries are included in the interim consolidated financial statements from the date that control commences until the date that control ceases.

The acquisition method of accounting is used to account for acquisitions of subsidiaries and assets that meet the definition of a business under IFRS. The cost of an acquisition is measured as the fair value of the assets given, equity instruments issued and liabilities incurred or assumed at the date of exchange. Identifiable assets acquired and liabilities and contingent liabilities assumed in a business combination are measured initially at their recognized amounts (generally fair value) at the acquisition date. The excess of the cost of acquisition over the recognized amounts of the identifiable assets, liabilities and contingent liabilities acquired is recorded as goodwill. If the cost of acquisition is less than the fair value of the net assets of the subsidiary acquired, a bargain purchase gain is recognized immediately in the consolidated statement of operations.

*(ii) Jointly controlled operations and jointly controlled assets.* Many of the Company's oil and natural gas activities involve jointly controlled assets. The consolidated financial statements include the Company's share of these jointly controlled assets and the proportionate share of the relevant revenue and related costs.

*(iii) Transactions eliminated on consolidation.* Intercompany balances and transactions, and any unrealized income and expenses arising from intercompany transactions, are eliminated in preparing the interim consolidated financial statements.

### *(b) Financial instruments:*

*(i) Non-derivative financial instruments.* Non-derivative financial instruments comprise cash and cash equivalents, accounts receivable and accruals, accounts payables and accruals, bank loans and convertible debentures. Non-derivative financial instruments are recognized initially at fair value, plus, for instruments not classified as "fair value through profit or loss", any directly attributable transaction costs. Subsequent to initial recognition, non-derivative financial instruments are measured as described below.

*Cash and cash equivalents.* Cash and cash equivalents comprise cash on hand, term deposits and other short-term highly liquid investments with original maturities of three months or less and is measured similar to other non-derivative financial instruments.

*Other.* Other non-derivative financial instruments, comprising accounts receivable and accruals, accounts payable and accruals, bank loans and convertible debentures, are measured at amortized cost using the effective interest method, less any impairment losses. 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. Bank loans and convertible

### 3. SIGNIFICANT ACCOUNTING POLICIES *(Continued)*

debentures are recorded net of issue costs and are presented net of deferred interest payments, with interest recognized in earnings on an effective interest basis.

*(ii) Derivative financial instruments.* The Company has entered into certain financial derivative contracts in order to manage the exposure to market risks from fluctuations in commodity prices. These instruments are not used for trading or speculative purposes. The Company has not designated its financial derivative contracts as effective accounting hedges, and thus has not applied hedge accounting, even though the Company considers all commodity contracts to be economic hedges. As a result, all financial derivative contracts are classified as “fair value through profit or loss” and are recorded on the statement of financial position at fair value. Transaction costs are recognized in profit or loss when incurred.

The Company accounts for forward physical delivery sales contracts, which are entered into and held for the purpose of delivery or receipt of non-financial items in accordance with expected sale or usage requirements as executory contracts. As such, these contracts are not considered to be derivative financial instruments and have not been recorded at fair value on the statement of financial position. Settlements on these physical sales contracts are recognized in oil and natural gas revenue.

Embedded derivatives are separated from the host contract and accounted for separately if the economic characteristics and risks of the host contract and the embedded derivative are not closely related, a separate instrument with the same terms as the embedded derivative would meet the definition of a derivative, and the combined instrument is not measured at “fair value through profit or loss”. Changes in the fair value of separable embedded derivatives are recognized immediately in profit or loss.

*(iii) Share capital.* Common shares are classified as equity. Incremental costs directly attributable to the issue of common shares and stock options are recognized as a deduction from equity, net of any tax effects.

#### *(c) Property, plant and equipment:*

##### *(i) Recognition and measurement.*

*Exploration and evaluation expenditures.* Pre-licence costs are recognized in the statement of operations and comprehensive loss as incurred. Generally, costs designated as exploration and evaluation assets are initially capitalized, are assessed for impairment when there are indicators of impairment present and are transferred to development and production assets upon determination of reserves. As of March 31, 2011, the Company has not identified any costs as exploration and evaluation assets (December 31, 2010 – \$Nil, January 1, 2010 - \$Nil).

*Development and production costs.* Items of property, plant and equipment, which include oil and gas development and production assets, are measured at cost less accumulated depletion and depreciation and accumulated impairment losses. Development and production assets are grouped into cash generating units (“CGU’s”) for impairment testing. The Company has grouped its development and production assets into the following CGU’s: Horizontal Oil, Deep Gas, Shallow Gas and Non-Core. The cost of property, plant and equipment at January 1, 2010, the date of transition to IFRS, was determined using the IFRS 1 deemed cost election, whereby the costs at transition were allocated to CGU’s based on reserves and tested for impairment. The Company chose to allocate its costs based on proved plus probable reserves volumes. When significant parts of an item of property, plant and equipment, including oil and natural gas interests, have different useful lives, they are accounted for as separate items (components).

### 3. SIGNIFICANT ACCOUNTING POLICIES *(Continued)*

Gains and losses on disposal of an item of property, plant and equipment, including oil and natural gas interests, are determined by comparing the proceeds from disposal with the carrying amount of property, plant and equipment and are recognized as separate line items in profit or loss.

*(ii) Subsequent costs.* Costs incurred subsequent to the determination of technical feasibility and commercial viability and the costs of replacing parts of property, plant and equipment are recognized as oil and natural gas interests only when they increase the future economic benefits embodied in the specific asset to which they relate. All other expenditures are recognized in profit or loss as incurred. Such capitalized oil and natural gas interests generally represent costs incurred in developing proved and/or probable reserves and bringing in or enhancing production from such reserves, and are accumulated on a field or geotechnical area basis. The carrying amount of any replaced or sold component is derecognized. The costs of the day-to-day servicing of property, plant and equipment are recognized in profit or loss as incurred.

*(iii) Depletion and depreciation.* The net carrying value of development or production assets is depleted using the unit of production method by reference to the ratio of production in the quarter to the related proved and probable reserves, taking into account estimated future development and decommissioning costs necessary to bring those reserves into production. These estimates are reviewed by independent reserves engineers at least annually.

Proved and probable reserves are estimated using independent reserves evaluator reports and represent the estimated quantities of crude oil, natural gas and natural gas liquids which geological, geophysical and engineering data demonstrate with a specified degree of certainty to be recoverable in future years from known reservoirs and which are considered commercially producible. There should be a 50 percent statistical probability that the actual quantity of recoverable reserves will be more than the amount estimated as proved and probable and a 50 percent statistical probability that it will be less. The equivalent statistical probabilities for the proved component of proved and probable reserves are 90 percent and 10 percent, respectively.

Such reserves may be considered commercially producible if management has the intention of developing and producing them and such intention is based upon:

- a reasonable assessment of the future economics of such production;
- a reasonable expectation that there is a market for all or substantially all the expected oil and natural gas production; and
- evidence that the necessary production, transmission and transportation facilities are available or can be made available.

Reserves may only be considered proved and probable if producibility is supported by either actual production or a conclusive formation test. The area of reservoir considered proved includes (a) that portion delineated by drilling and defined by gas-oil and/or oil-water contacts, if any, or both, and (b) the immediately adjoining portions not yet drilled, but which can be reasonably judged as economically productive on the basis of available geophysical, geological and engineering data. In the absence of information on fluid contacts, the lowest known structural occurrence of oil and natural gas controls the lower proved limit of the reservoir.

### 3. SIGNIFICANT ACCOUNTING POLICIES *(Continued)*

Reserves which can be produced economically through application of improved recovery techniques (such as fluid injection) are only included in the proved and probable classification when successful testing by a pilot project, the operation of an installed program in the reservoir, or other reasonable evidence (such as, experience of the same techniques on similar reservoirs or reservoir simulation studies) provides support for the engineering analysis on which the project or program was based.

As of March 31, 2011, the Company has not identified any components that would be depreciated on a different basis than the unit of production method.

For other assets, depreciation is recognized in profit or loss over the estimated useful lives of each part of an item of property, plant and equipment using the declining balance method at rates between 20% and 30% per annum. Leased assets are depreciated over the shorter of the lease term and their useful lives unless it is reasonably certain that the Company will obtain ownership by the end of the lease term.

Depreciation methods, useful lives and residual values are reviewed at each reporting date.

*(d) Leased assets.* Operating leases are not recognized on the Company's statement of financial position.

Payments made under operating leases are recognized in profit or loss on a straight-line basis over the term of the lease. Lease incentives received are recognized as an integral part of the total lease expense, over the term of the lease.

*(e) Impairment:*

*(i) Financial assets.* A financial asset is assessed at each reporting date to determine whether there is any objective evidence that it is impaired. A financial asset is considered to be impaired if objective evidence indicates that one or more events have had a negative effect on the estimated future cash flows of that asset.

An impairment loss in respect of a financial asset measured at amortized cost is calculated as the difference between its carrying amount and the present value of the estimated future cash flows discounted at the original effective interest rate.

Individually significant financial assets are tested for impairment on an individual basis. The remaining financial assets are assessed collectively in groups that share similar credit risk characteristics.

All impairment losses are recognized in profit or loss.

An impairment loss is reversed if the reversal can be related objectively to an event occurring after the impairment loss was recognized. For financial assets measured at amortized cost the reversal is recognized in profit or loss.

*(ii) Non-financial assets.* The carrying amounts of the Company's non-financial assets, other than deferred tax assets are reviewed at each reporting date to determine whether there is any indication of impairment. If any such indication exists, then the asset's recoverable amount is estimated.

For the purpose of impairment testing, assets are grouped together into the smallest group of assets that generates cash inflows from continuing use that are largely independent of the cash inflows of other assets or groups of assets (the "cash-generating unit" or "CGU"). The recoverable amount of an asset or a CGU is the greater of its value in use and its fair value less costs to sell.

### 3. SIGNIFICANT ACCOUNTING POLICIES *(Continued)*

In assessing value in use, the estimated future cash flows are discounted to their present value using a pre-tax discount rate that reflects current market assessments of the time value of money and the risks specific to the asset. Value in use is generally computed by reference to the present value of the future cash flows expected to be derived from production of proved and probable reserves.

Fair value less cost to sell is determined as the amount that would be obtained from the sale of a CGU in an arm's length transaction between knowledgeable and willing parties. The fair value less cost to sell of oil and gas assets is generally determined as the net present value of the estimated future cash flows expected to arise from the continued use of the CGU, including any expansion prospects, and its eventual disposal, using assumptions that an independent market participant may take into account. These cash flows are discounted by an appropriate discount rate which would be applied by such a market participant to arrive at a net present value of the CGU.

An impairment loss is recognized if the carrying amount of an asset or its CGU exceeds its estimated recoverable amount. Impairment losses are recognized in profit or loss. Impairment losses recognized in respect of CGU's are allocated first to reduce the carrying amount of any goodwill allocated to the units and then to reduce the carrying amounts of the other assets in the unit on a pro rata basis.

Impairment losses recognized in prior years are assessed at each reporting date for any indications that the loss has decreased or no longer exists. An impairment loss is reversed if there has been a change in the estimates used to determine the recoverable amount. An impairment loss is reversed only to the extent that the asset's carrying amount does not exceed the carrying amount that would have been determined, net of depletion and depreciation, if no impairment loss had been recognized.

*(f) Share-based payments.* The grant date fair value of equity-settled options granted to employees is recognized as stock-based compensation expense, within general and administrative expenses, with a corresponding increase in contributed surplus over the vesting period. A forfeiture rate is estimated on the grant date and is adjusted to reflect the actual number of options that vest.

*(g) Provisions.* A provision is recognized if, as a result of a past event, the Company has a present legal or constructive obligation that can be estimated reliably, and it is probable that an outflow of economic benefits will be required to settle the obligation. Provisions are determined by discounting the expected future cash flows at a pre-tax rate that reflects current market assessments of the time value of money and the risks specific to the liability. Provisions are not recognized for future operating losses.

*Decommissioning obligations.* The Company's activities give rise to dismantling, decommissioning and site disturbance remediation activities. Provision is made for the estimated cost of site restoration and capitalized in the relevant asset category.

Decommissioning obligations are measured at the present value of management's best estimate of the expenditures required to settle the present obligation at the balance sheet date. Subsequent to the initial measurement, the obligation is adjusted at the end of each period to reflect the passage of time and changes in the estimated future cash flows underlying the obligation. The increase in the provision due to the passage of time is recognized as finance costs whereas increases/decreases due to changes in the estimated future cash flows are capitalized. Actual costs incurred upon settlement of the asset retirement obligations are charged against the provision to the extent the provision was established.

### 3. SIGNIFICANT ACCOUNTING POLICIES *(Continued)*

*(h) Revenue.* Revenue from the sale of oil and natural gas is recorded when the significant risks and rewards of ownership of the product is transferred to the buyer which is usually when legal title passes to the external party. This is generally at the time product enters the pipeline. Revenue is presented both before and after royalties payable to the Crown and others.

Transportation costs are netted from revenue where title transfers prior to transport on applicable sales pipelines and the transportation is held by and charged by the purchaser. Other transportation and processing fees are included in operating expenses.

Royalty income is recognized as it accrues in accordance with the terms of the overriding royalty agreements.

*(i) Finance income and expenses.* Finance expense comprises interest expense on borrowings, accretion of the discount on decommissioning obligations and accretion on convertible debentures recognized as financial liabilities.

Interest income is recognized as it accrues in profit or loss, using the effective interest method.

*(j) Income tax.* Income tax expense comprises current and deferred tax. Income tax expense is recognized in profit or loss except to the extent that it relates to items recognized directly in equity, in which case it is recognized in equity.

Current tax is the expected tax payable on the taxable income for the year, using tax rates enacted or substantively enacted at the reporting date, and any adjustment to tax payable in respect of previous years.

Deferred tax is recognized using the balance sheet method, providing for temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for taxation purposes. Deferred tax is not recognized on the initial recognition of assets or liabilities in a transaction that is not a business combination. In addition, deferred tax is not recognized for taxable temporary differences arising on the initial recognition of goodwill. Deferred tax is measured at the tax rates that are expected to be applied to temporary differences when they reverse, based on the laws that have been enacted or substantively enacted by the reporting date. Deferred tax assets and liabilities are offset if there is a legally enforceable right to offset, and they relate to income taxes levied by the same tax authority on the same taxable entity, or on different tax entities, but they intend to settle current tax liabilities and assets on a net basis or their tax assets and liabilities will be realized simultaneously.

A deferred tax asset is recognized to the extent that it is probable that future taxable profits will be available against which the temporary difference can be utilized. Deferred tax assets are reviewed at each reporting date and are reduced to the extent that it is no longer probable that the related tax benefit will be realized.

*(k) Earnings per share.* Basic earnings per share is calculated by dividing the profit or loss attributable to common shareholders of the Company by the weighted average number of common shares outstanding during the period. Diluted earnings per share is determined by adjusting the profit or loss attributable to common shareholders and the weighted average number of common shares outstanding for the effects of dilutive instruments such as options granted to employees.

### **3. SIGNIFICANT ACCOUNTING POLICIES** *(Continued)*

#### *(l) New standards and interpretations not yet adopted:*

The Company is currently reviewing the following new and revised accounting pronouncements that have been issued but are not yet effective to determine if they may have an impact on the Company:

*IFRS 9 – Financial Instruments.* In November 2009, the IASB published IFRS 9 “Financial Instruments” which covers the classification and measurement of financial assets as part of its project to replace IAS 39 “Financial Instruments: Recognition and Measurement.” IFRS 9 uses a single approach to determine whether a financial asset is measured at amortized cost or fair value, replacing the multiple rules in IAS 39. The approach in IFRS 9 is based on how an entity managed its financial instruments in the context of its business model and the contractual cash flow characteristics of the financial assets. The new standard also requires a single impairment method to be used, replacing the multiple impairment methods in IAS 39.

In October 2010, additional requirements for classifying and measuring financial liabilities were added to IFRS 9. Under this guidance, entities have the option to recognize financial liabilities at fair value through profit or loss. If this option is elected, entities would be required to reverse the portion of the fair value change due to own credit risk out of profit or loss and recognize the change in other comprehensive income.

IFRS 9 will become effective for the Company on January 1, 2013. Early adoption is permitted and the standard is required to be applied retrospectively. The implementation of the issued standard is not expected to have a significant impact on the Company’s financial position or results.

*IAS 12 – Income Taxes.* IAS 12 “Income Taxes” was amended on December 20, 2010 to remove subjectivity in determining on which basis an entity measures the deferred tax relating to an asset. The amendment introduces a presumption that an entity will assess whether the carrying value of an asset will be recovered through the sale of the asset. The amendment to IAS 12 is effective for reporting periods beginning on or after January 1, 2012. The Company is currently evaluating the impact of this amendment to its financial statements.

### **4. DETERMINATION OF FAIR VALUE**

A number of the Company’s accounting policies and disclosures require the determination of fair value, for both financial and non-financial assets and liabilities. Fair values have been determined for measurement and/or disclosure purposes based on the following methods. When applicable, further information about the assumptions made in determining fair values is disclosed in the notes specific to that asset or liability.

*(i) Property, plant and equipment.* Property, plant and equipment is recognized at fair value in a business combination. The fair value of property, plant and equipment is the estimated amount for which property, plant and equipment could be exchanged on the acquisition date between a willing buyer and a willing seller in an arm’s length transaction after proper marketing wherein the parties had each acted knowledgeably, prudently and without compulsion. The fair value of oil and natural gas interests (included in property, plant and equipment) is estimated with reference to the discounted cash flows expected to be derived from oil and natural gas production based on externally prepared reserve reports. The risk-adjusted discount rate is specific to the asset with reference to general market conditions, being 10% for 2011 (2010 – 10%).

The market value of other items of property, plant and equipment is based on the quoted market prices for similar items.

#### 4. DETERMINATION OF FAIR VALUE *(Continued)*

*(ii) Cash and cash equivalents, accounts receivable and accruals and accounts payable and accruals.* The fair value of cash and cash equivalents, accounts receivable and accruals and accounts payable and accruals is estimated as the present value of future cash flows, discounted at the market rate of interest at the reporting date. At March 31, 2011 and 2010, the fair value of these balances approximated their carrying value due to their short term to maturity.

*(iii) Bank loans.* The fair value of bank loans approximates their carrying value, as they bear interest at floating rates and the premium charged at March 31, 2011 and December 31, 2010 was indicative by the Company's current credit spreads.

*(iv) Derivatives.* The fair value of forward contracts and swaps is derived from quoted prices received from financial institutions and is based on published forward price curves as at the measurement date, using the remaining contracted oil and natural gas volumes.

*(v) Stock options.* The fair value of employee stock options is measured using a Black Scholes option pricing model. Measurement inputs include share price on measurement date, exercise price of the instrument, expected volatility (based on weighted average historic volatility adjusted for changes expected due to publicly available information), weighted average expected life of the instruments (based on historical experience and general option holder behaviour), expected dividends, and the risk-free interest rate (based on government bonds).

The Company classified the fair value of its financial instruments measured at fair value according to the following hierarchy based on the amount of observable inputs used to value the instrument:

- 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.

The fair value of the derivative contracts used for risk management as shown in the consolidated statements of financial position as at March 31, 2011 and December 2010 is measured using level 2.

During the periods ended March 31, 2011 and 2010, there were no transfers between level 1, level 2 and level 3 classified assets and liabilities.

#### 5. FINANCIAL RISK MANAGEMENT

*(a) Overview.* The Company's activities expose it to a variety of financial risks that arise as a result of its exploration, development, production, and financing activities such as:

- credit risk;
- liquidity risk; and
- market risk.

This note presents information about the Company's exposure to each of the above risks, the Company's objectives, policies and processes for measuring and managing risk, and the Company's management of capital. Further quantitative disclosures are included throughout these consolidated financial statements.

## 5. FINANCIAL RISK MANAGEMENT *(Continued)*

The Board of Directors oversees managements' establishment and execution of the Company's risk management framework. Management has implemented and monitors compliance with risk management policies. 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.

*(b) 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, and arises principally from the Company's receivables from joint venture partners and oil and natural gas marketers. The maximum exposure to credit risk at year-end is as follows:

|                                  | <i>Carrying Amount</i> |                          |                        |
|----------------------------------|------------------------|--------------------------|------------------------|
|                                  | <i>March 31, 2011</i>  | <i>December 31, 2010</i> | <i>January 1, 2010</i> |
| Cash and cash equivalents        | \$ -                   | \$ 4,024                 | \$ 1                   |
| Accounts receivable and accruals | 18,581                 | 20,998                   | 22,990                 |
|                                  | <u>\$ 18,581</u>       | <u>\$ 25,022</u>         | <u>\$ 22,991</u>       |

*Accounts receivable and accruals.* All of the Company's operations are conducted in Canada. The Company's exposure to credit risk is influenced mainly by the individual characteristics of each purchaser or joint venture partner.

Receivables from oil and natural gas marketers are normally 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 collection issues with its oil and natural gas marketers. Receivables from joint venture partners are typically collected within one to three months of the joint venture bill being issued. The Company attempts to mitigate the risk from joint venture receivables by obtaining venturer pre-approval of significant capital expenditures. However, the receivables are from participants in the oil and natural gas sector, and collection of the outstanding balances is dependent on industry factors such as commodity price fluctuations, escalating costs and the risk of unsuccessful drilling. In addition, further risk exists with joint venturers as disagreements occasionally arise that increase the potential for non-collection.

The Company does not typically obtain collateral from oil and natural gas marketers or joint venturers; however, the Company does have the ability to withhold production from joint venturers in the event of non-payment.

The Company's allowance for doubtful accounts as at March 31, 2011 was \$0.9 million (December 31, 2010 – \$1.0 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 \$35,000 in receivables during the three months ended March 31, 2011 (March 31, 2010 – \$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.

## 5. FINANCIAL RISK MANAGEMENT *(Continued)*

The maximum exposure to credit risk for accounts receivable and accruals, net of allowance for doubtful accounts at the reporting date by type of customer was:

|   | <i>Carrying Amount</i> |                          |                        |
|---|------------------------|--------------------------|------------------------|
|   | <i>March 31, 2011</i>  | <i>December 31, 2010</i> | <i>January 1, 2010</i> |
| Oil and natural gas marketing companies | \$ 9,386               | \$ 9,286                 | \$ 8,213               |
| Joint venture partners                  | 6,239                  | 7,989                    | 7,790                  |
| Other                                   | 2,956                  | 3,723                    | 6,987                  |
|   | <u>\$ 18,581</u>       | <u>\$ 20,998</u>         | <u>\$ 22,990</u>       |

As at March 31, 2011, December 31, 2010 and January 1, 2010, the Company's accounts receivable and accruals was aged as follows:

| <i>Aging</i>                   | <i>March 31, 2011</i> | <i>December 31, 2010</i> | <i>January 1, 2010</i> |
|--------------------------------|-----------------------|--------------------------|------------------------|
| Not past due                   | \$ 17,610             | \$ 18,960                | \$ 22,402              |
| Past due by less than 120 days | 602                   | 1,706                    | 537                    |
| Past due by more than 120 days | 369                   | 332                      | 51                     |
| Total                          | <u>\$ 18,581</u>      | <u>\$ 20,998</u>         | <u>\$ 22,990</u>       |

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

*(c) Liquidity risk.* Liquidity risk is the risk that the Company will not be able to meet its financial obligations as they fall due. The Company's approach to managing liquidity is to ensure, as far as possible, that it will always have sufficient liquidity to meet its liabilities when due, under both normal and stressed conditions, without incurring unacceptable losses or risking damage to the Company's reputation.

To achieve this objective, 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 provide capital when needed, the Company has revolving reserves-based credit facilities which are reviewed semi-annually by its lenders. These facilities are described in note 10. The Company also attempts to match its payment cycle with collection of oil and natural gas revenue on the 25th of each month.

## 5. FINANCIAL RISK MANAGEMENT *(Continued)*

The following are the contractual maturities of financial liabilities, including associated interest payments on convertible debentures and excluding the impact of netting agreements at March 31, 2011:

| <i>Financial Liabilities</i>                 | <i>Less than one year</i> | <i>One to two years</i> | <i>Two to three years</i> | <i>Three to four years</i> | <i>Four to five years</i> |
|--|---------------------------|-------------------------|---------------------------|----------------------------|---------------------------|
| <i>Non-derivative financial liabilities</i>  |                           |                         |                           |                            |                           |
| Accounts payable and accruals <sup>(1)</sup> | \$ 65,112                 | \$ -                    | \$ -                      | \$ -                       | -                         |
| Bank loans – principal <sup>(2)</sup>        | -                         | 59,247                  | -                         | -                          | -                         |
| <i>Convertible debentures</i>                |                           |                         |                           |                            |                           |
| - Interest <sup>(1)</sup>                    | 3,125                     | 3,750                   | 3,750                     | 3,750                      | 3,750                     |
| - Principal                                  | -                         | -                       | -                         | -                          | 50,000                    |
| <i>Derivative financial liabilities</i>      |                           |                         |                           |                            |                           |
| Derivative contracts - outflow               | 4,595                     | 172                     | -                         | -                          | -                         |
| <b>Total</b>                                 | <b>\$ 72,832</b>          | <b>\$ 63,169</b>        | <b>\$ 3,750</b>           | <b>\$ 3,750</b>            | <b>\$ 53,750</b>          |

(1) Accounts payable and accruals includes \$0.9 million of interest relating to convertible debentures. The total cash interest payable in less than one year on the convertible debentures is \$4.1 million.

(2) Assumes the credit facilities are not renewed on July 12, 2011. Subsequent to March 31, 2011, the Company agreed with its lenders to renew the facilities to July 12, 2012 (see note 10).

**(d) Market risk.** Market risk is the risk that changes in market prices, such as commodity prices, foreign exchange rates and interest rates will affect the Company's income or the value of the financial instruments. The objective of market risk management is to manage and control market risk exposures within acceptable parameters, while optimizing the return.

The Company may use both financial derivatives and physical delivery sales contracts to manage market risks. All such transactions are conducted within risk management tolerances that are reviewed by the Board of Directors.

**Currency risk.** Prices for oil are determined in global markets and generally denominated in United States dollars. Natural gas prices obtained by the Company are influenced by both U.S. and Canadian demand and the corresponding North American supply, and recently, by imports of liquefied natural gas. The exchange rate effect cannot be quantified but generally an increase in the value of the Canadian dollar as compared to the U.S. dollar will reduce the prices received by the Company for its petroleum and natural gas sales.

There were no financial instruments denominated in U.S. dollars at March 31, 2011 or December 31, 2010.

**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 interest charged on the outstanding bank loans fluctuates with the interest rates posted by the lenders. The Company has not entered into any mitigating interest rate hedges or swaps, however at December 31, 2010, the Company issued \$50 million of convertible debentures at a fixed interest rate of 7.5% maturing January 31, 2016. Had the borrowing rate on bank loans been 100 basis points higher (or lower) throughout the three months ended March 31, 2011, net loss would have been affected by \$86,400 (March 31, 2010 – \$81,800) based on the average bank debt balance outstanding during the period.

**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 oil and natural gas are impacted by both the relationship between the Canadian and U.S. dollar and world economic events that dictate the levels of supply and demand.

## 5. FINANCIAL RISK MANAGEMENT *(Continued)*

It is the Company's policy to economically hedge some oil and natural gas sales through the use of various financial derivative forward sales contracts and physical sales contracts. The Company does not apply hedge accounting for these contracts. The Company's production is usually sold using "spot" or near term contracts, with prices fixed at the time of transfer of custody or on the basis of a monthly average market price. The Company, however, may give consideration in certain circumstances to the appropriateness of entering into long term, fixed price marketing contracts. The Company does not enter into commodity contracts other than to meet the Company's expected sale requirements.

At March 31, 2011 the following derivative contracts were outstanding and recorded at estimated fair value:

| <i>Type of Contract<sup>(1)</sup></i> | <i>Commodity</i> | <i>Volume</i>  | <i>Weighted<br/>Average<br/>Fixed Price<br/>(NYMEX<br/>Canadian \$)</i> | <i>Remaining Period</i>       |
|---------------------------------------|------------------|----------------|---|-------------------------------|
| Financial swap                        | Crude oil        | 1,000 bbls/day | \$ 88.45/bbl  | April 1, 2011 to Dec 31, 2011 |
| Financial swap                        | Crude oil        | 500 bbls/day   | \$ 103.10/bbl   | Jan 1, 2012 to Dec 31, 2012   |

*(1) Swap indicates fixed price payable to Anderson in exchange for floating price payable to counterparty.*

The estimated fair value of the financial oil contracts has been determined on the amounts the Company would receive or pay to terminate the oil contracts. At March 31, 2011, the amount the Company would pay to terminate the contracts would be \$4.8 million.

The fair value of the financial commodity risk management contracts have been allocated to current and non-current liabilities on a contract by contract basis as follows:

|              | <i>March 31, 2011</i> | <i>December 31, 2010</i> | <i>January 1, 2010</i> |
|--------------|-----------------------|--------------------------|------------------------|
| Liabilities: |                       |                          |                        |
| Current      | \$ 4,595              | \$ 1,918                 | \$ -                   |
| Long-term    | 172                   | -                        | -                      |
| Net position | <u>\$ 4,767</u>       | <u>\$ 1,918</u>          | <u>\$ -</u>            |

The fair value of derivative contracts at March 31, 2011 would have been impacted as follows had the forward price curves used to estimated the fair value changed by:

|  | <i>Effect of an<br/>increase in price<br/>on after-tax<br/>earnings</i> | <i>Effect of a<br/>decrease in price<br/>on after-tax<br/>earnings</i> |
|--|---|--|
| Canadian \$1.00 per barrel change in the oil price | \$ (339)  | \$ 339   |

## 5. FINANCIAL RISK MANAGEMENT *(Continued)*

In April 2011, the Company entered into the following fixed price contracts:

| <i>Type of Contract<sup>(1)</sup></i> | <i>Commodity</i> | <i>Volume</i> | <i>Weighted<br/>Average<br/>Fixed Price<br/>(NYMEX<br/>Canadian \$)</i> | <i>Remaining Period</i>       |
|---------------------------------------|------------------|---------------|---|-------------------------------|
| Financial swap                        | Crude oil        | 250 bbls/day  | \$ 106.00/bbl   | May 1, 2011 to Dec 31, 2011   |
| Financial swap                        | Crude oil        | 250 bbls/day  | \$ 105.15/bbl   | July 1, 2011 to Sept 30, 2011 |
| Financial swap                        | Crude oil        | 250 bbls/day  | \$ 105.30/bbl   | Oct 1, 2011 to Dec 31, 2011   |
| Financial swap                        | Crude oil        | 500 bbls/day  | \$ 106.04/bbl   | Jan 1, 2012 to Mar 31, 2012   |
| Financial swap                        | Crude oil        | 500 bbls/day  | \$ 104.75/bbl   | Jan 1, 2012 to Dec 31, 2012   |

*(1) Swap indicates fixed price payable to Anderson in exchange for floating price payable to counterparty.*

*(e) Capital management.* 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 \$178.6 million, bank loans of \$59.2 million, convertible debentures with a face value of \$50.0 million and the working capital deficiency of \$43.7 million, excluding the current portion of unrealized loss on derivative contracts. 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 cash 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 including decommissioning 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.

## 5. FINANCIAL RISK MANAGEMENT *(Continued)*

|  | <i>March 31,<br/>2011</i> | <i>December<br/>31, 2010</i> |
|--|---------------------------|------------------------------|
| Bank loans   | \$ 59,247                 | \$ 52,719                    |
| Current liabilities, excluding unrealized loss on derivative contracts | 65,112                    | 46,862                       |
| Current assets   | (21,388)                  | (28,074)                     |
| Net debt before convertible debentures                                 | \$ 102,971                | \$ 71,507                    |
| Convertible debentures (liability component)                           | 43,679                    | 43,460                       |
| Total net debt   | \$ 146,650                | \$ 114,967                   |
| Cash from operating activities in quarter                              | \$ 11,001                 | \$ 10,489                    |
| Decommissioning expenditures   | 26                        | 118                          |
| Changes in non-cash working capital                                    | (159)                     | (1,324)                      |
| Funds from operations in quarter                                       | \$ 10,868                 | \$ 9,283                     |
| Annualized current quarter funds from operations                       | \$ 43,472                 | \$ 37,132                    |
| Net debt before convertible debentures to funds from operations        | 2.4                       | 1.9                          |
| Total net debt to funds from operations                                | 3.4                       | 3.1                          |

There were no changes in the Company's approach to capital management during the period.

As at March 31, 2011, the Company's ratio of net debt before convertible debentures to annualized cash flow was 2.4 to 1 (December 31, 2010 – 1.9 to 1). As at March 31, 2011, the Company's ratio of total net debt to annualized cash flow was 3.4 to 1 (December 31, 2010 – 3.0 to 1). The higher ratios reflect the capital expenditures required to make the transition from a gas weighted company to an oil weighted company. As new crude oil production is brought on-stream at higher expected operating margins, the debt to funds from operations ratio is expected to decrease.

Neither the Company nor any of its subsidiaries are subject to externally imposed capital requirements. The credit facilities are subject to a semi-annual review of the borrowing base which is directly impacted by the value of the oil and natural gas reserves.

## 6. FINANCE INCOME AND EXPENSES

|  | <i>March 31, 2011</i> | <i>March 31, 2010</i> |
|--|-----------------------|-----------------------|
| Income:                                    |                       |                       |
| Interest income on cash equivalents        | \$ 3                  | \$ -                  |
| Other                                      | 20                    | 58                    |
| Expenses:                                  |                       |                       |
| Interest and financing costs on bank loans | (818)                 | (685)                 |
| Interest on convertible debentures         | (938)                 | -                     |
| Accretion on convertible debentures        | (219)                 | -                     |
| Accretion on decommissioning obligations   | (417)                 | (403)                 |
| Other                                      | (17)                  | (14)                  |
| Net finance expenses                       | \$ (2,386)            | \$ (1,044)            |

## 7. SUPPLEMENTAL CASH FLOW INFORMATION

Changes in non-cash working capital is comprised of:

|                                  | March 31, 2011   | March 31, 2010   |
|----------------------------------|------------------|------------------|
| Source (use) of cash             |                  |                  |
| Accounts receivable and accruals | \$ 2,417         | \$ 2,152         |
| Prepaid expenses and deposits    | 245              | (161)            |
| Accounts payable and accruals    | 18,250           | 14,817           |
|                                  | <u>\$ 20,912</u> | <u>\$ 16,808</u> |
| Related to operating activities  | \$ 159           | \$ 2,540         |
| Related to financing activities  | \$ (294)         | \$ 260           |
| Related to investing activities  | \$ 21,047        | \$ 14,008        |

## 8. PROPERTY, PLANT AND EQUIPMENT

### *Cost or deemed cost*

|                              | <i>Oil and natural<br/>gas assets</i> | <i>Other<br/>equipment</i> | <i>Total</i>      |
|------------------------------|---------------------------------------|----------------------------|-------------------|
| Balance at January 1, 2010   | \$ 469,762                            | \$ 1,713                   | \$ 471,475        |
| Additions                    | 118,140                               | 67                         | 118,207           |
| Disposals                    | (2,407)                               | -                          | (2,407)           |
| Balance at December 31, 2010 | 585,495                               | 1,780                      | 587,275           |
| Additions                    | 48,708                                | 2                          | 48,710            |
| Disposals                    | (10,213)                              | -                          | (10,213)          |
| Balance at March 31, 2011    | <u>\$ 623,990</u>                     | <u>\$ 1,782</u>            | <u>\$ 625,772</u> |

### *Accumulated depletion, depreciation and impairment losses*

|   | <i>Oil and natural<br/>gas assets</i> | <i>Other<br/>equipment</i> | <i>Total</i>      |
|---|---------------------------------------|----------------------------|-------------------|
| Opening balance at January 1, 2010        | \$ -                                  | \$ 1,075                   | \$ 1,075          |
| Impairment loss at January 1, 2010        | 67,193                                | -                          | 67,193            |
| Balance at January 1, 2010                | 67,193                                | 1,075                      | 68,268            |
| Depletion and depreciation for the year   | 45,484                                | 168                        | 45,652            |
| Impairment loss                           | 153,165                               | -                          | 153,165           |
| Disposals                                 | (484)                                 | -                          | (484)             |
| Balance at December 31, 2010              | \$ 265,358                            | \$ 1,243                   | \$ 266,601        |
| Depletion and depreciation for the period | 12,319                                | 36                         | 12,355            |
| Disposals                                 | (5,183)                               | -                          | (5,183)           |
| Balance at March 31, 2011                 | <u>\$ 272,494</u>                     | <u>\$ 1,279</u>            | <u>\$ 273,773</u> |

### *Carrying amounts*

|                      | <i>Oil and natural<br/>gas assets</i> | <i>Other<br/>equipment</i> | <i>Total</i>      |
|----------------------|---------------------------------------|----------------------------|-------------------|
| At January 1, 2010   | \$ 402,569                            | \$ 638                     | \$ 403,207        |
| At December 31, 2010 | \$ 320,137                            | \$ 537                     | \$ 320,674        |
| At March 31, 2011    | <u>\$ 351,496</u>                     | <u>\$ 503</u>              | <u>\$ 351,999</u> |

## 8. PROPERTY, PLANT AND EQUIPMENT *(Continued)*

*Depletion, depreciation and impairment charges.* Depletion and depreciation, impairment of property, plant and equipment, and any eventual reversal thereof, are recognized as separate line items in the consolidated statement of operations (see note 9).

## 9. IMPAIRMENT LOSS

As a result of applying the IFRS 1 exemption for deemed cost at January 1, 2010, the Company was required to test all of its cash generating units for impairment. At March 31, 2010, September 30, 2010 and December 31, 2010, due to declines in the forward curve for natural gas prices, the Company tested the Shallow Gas, Deep Gas and Non-core CGUs for impairment. In addition, as a result of continued weakness in natural gas pricing at June 30, 2010, the Company tested the same CGUs for impairment. At March 31, 2011, there was no material change in the forward curve for natural gas prices and there was an increase in oil and natural gas liquids prices from December 31, 2010, therefore the Company did not test for impairment of its CGUs, or reverse any of the impairments previously recognized.

The recoverable amount of the CGUs was estimated based on the higher of the value in use and the fair value less costs to sell. The estimate of fair value less costs to sell was determined using a discount rate of 10 percent and forecasted cash flows, with escalating prices and future development costs, as obtained from the reserve report. The prices used to estimate the fair value less cost to sell are those used by independent industry reserve engineers.

Based on this assessment at January 1, 2010, the carrying amount of the Shallow Gas CGU was determined to be \$67.2 million lower than its recoverable amount and thus an impairment was recorded. In addition, at March 31, 2010 the carrying amounts of the three natural gas CGUs were determined to be \$59.5 million lower than their recoverable amounts and an impairment was recorded.

The impairment losses recognized in each CGU were as follows:

|   | <i>Horizontal<br/>Oil CGU</i> | <i>Deep<br/>Gas CGU</i> | <i>Shallow<br/>Gas CGU</i> | <i>Non-Core<br/>CGU</i> | <i>Total<sup>(1)</sup></i> |
|---|-------------------------------|-------------------------|----------------------------|-------------------------|----------------------------|
| Impairment loss at January 1, 2010                                    | \$ -                          | \$ -                    | \$ 67,193                  | \$ -                    | \$ 67,193                  |
| Impairment loss for the quarter ended<br>March 31, 2010               | -                             | 6,587                   | 52,827                     | 126                     | 59,540                     |
| Impairment loss for the quarter ended<br>June 30, 2010                | -                             | 3,112                   | -                          | -                       | 3,112                      |
| Impairment loss for the quarter ended<br>September 30, 2010           | -                             | 15,996                  | 28,286                     | 4,035                   | 48,317                     |
| Impairment loss for the quarter ended<br>December 31, 2010            | -                             | 5,384                   | 35,033                     | 1,779                   | 42,196                     |
| Cumulative impairment loss at December<br>31, 2010 and March 31, 2011 | \$ -                          | \$ 31,079               | \$ 183,339                 | \$ 5,940                | \$ 220,358                 |
| Carrying value, January 1, 2010                                       | \$ 5,750                      | \$ 116,993              | \$ 233,237                 | \$ 44,795               | \$ 400,775                 |
| Carrying value, December 31, 2010                                     | \$ 63,687                     | \$ 94,091               | \$ 124,836                 | \$ 36,764               | \$ 319,378                 |
| Carrying value, March 31, 2011  | \$ 106,516                    | \$ 90,829               | \$ 116,918                 | \$ 35,772               | \$ 350,035                 |

*(1) Carrying values exclude inventory and corporate assets of \$2.4 million at January 1, 2010, \$1.3 million at December 31, 2010 and \$2.0 million at March 31, 2011.*

## 10. BANK LOANS

At March 31, 2011, 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

## 10. BANK LOANS *(Continued)*

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.

At March 31, 2011, there were no amounts drawn under the supplemental facility. The average effective interest rate on advances under the facilities in 2011 was 6.1% (March 31, 2010 – 4.5%). The Company had \$133,500 in letters of credit outstanding at March 31, 2011 that reduce 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. These margins vary from 1.75% to 6.50% depending on the borrowing option used and the Company's financial ratios.

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

On May 13, 2011, the Company agreed with its lenders to renew the credit facilities to July 12, 2012 at a total combined amount of \$135 million, subject to execution of customary documentation and normal closing conditions. The new facilities will consist of a \$100 million extendible revolving term credit facility, a \$10 million working capital credit facility and a \$25 million supplemental credit facility. If not extended, the extendible revolving term credit facility and working capital credit facility cease to revolve and all outstanding advances thereunder become repayable one year from the term date of July 12, 2012. The supplemental facility expires on July 12, 2012. Draws over \$10 million under the supplemental facility are subject to the consent of the bank syndicate at the time of the drawdown. The applicable margins vary from 1.50% to 6.00% depending on the borrowing option used and the Company's financial ratios.

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 in November 2011.

## 11. 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 or 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".

## 11. CONVERTIBLE DEBENTURES *(Continued)*

The Debentures were determined to be compound instruments. 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 \$50 million principal balance at maturity.

The following table indicates the convertible debenture activities:

|  | <i>Proceeds</i> | <i>Debt component</i> | <i>Equity component</i> |
|--|-----------------|-----------------------|-------------------------|
| Balance, December 31, 2009                   | \$ -            | \$ -                  | -                       |
| Issued pursuant to prospectus <sup>(1)</sup> | 50,000          | 45,553                | 4,447                   |
| Issue costs                                  | (2,300)         | (2,095)               | (205)                   |
| Deferred tax                                 | -               | -                     | (1,650)                 |
| Accretion expense                            | -               | 2                     | -                       |
| Balance, December 31, 2010                   | \$ 47,700       | \$ 43,460             | \$ 2,592                |
| Accretion expense                            | -               | 219                   | -                       |
| Balance, March 31, 2011                      | \$ 47,700       | \$ 43,679             | \$ 2,592                |

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

## 12. DECOMMISSIONING OBLIGATIONS

|                         | <i>March 31, 2011</i> | <i>December 31, 2010</i> |
|-------------------------|-----------------------|--------------------------|
| Balance at January 1    | \$ 51,550             | \$ 47,657                |
| Provisions incurred     | 852                   | 2,945                    |
| Provisions settled      | (26)                  | (1,549)                  |
| Provisions disposed     | (215)                 | (75)                     |
| Change in discount rate | 163                   | 634                      |
| Change in estimates     | 9                     | 284                      |
| Accretion expense       | 417                   | 1,654                    |
| Ending balance          | \$ 52,750             | \$ 51,550                |

The Company's decommissioning obligations result from its ownership interest in oil and natural gas assets including well sites and gathering systems. The total decommissioning obligation is estimated based on the Company's net ownership interest in all wells and facilities, estimated costs to reclaim and abandon these wells and facilities and the estimated timing of the costs to be incurred in future years. The Company has estimated the net present value of the decommissioning obligations to be \$52.8 million as at March 31, 2011 (December 31, 2010 – \$51.6 million) based on an undiscounted inflation-adjusted total future liability of \$74.6 million (December 31, 2010 – \$72.9 million). These payments are expected to be made over the next 25 years with the majority of costs to be incurred between 2012 and 2030. The discount factor, being the risk-free rate related to the liability, ranged from 0.8% to 4.4% (December 31, 2010 – 0.8% to 4.4%) depending on the estimated timing of the future obligation.

### 13. SHARE CAPITAL

*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.*

|   | <i>Number of<br/>Common Shares</i> | <i>Amount</i> |
|---|------------------------------------|---------------|
| Balance at January 1, 2010                                    | 150,500,401 \$                     | 396,524       |
| Issued pursuant to prospectus <sup>(1)</sup>                  | 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 \$                     | 426,925       |
| Stock options exercised                                       | 60,000                             | 73            |
| Balance at March 31, 2011                                     | 172,545,301 \$                     | 426,998       |

(1) 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 three months ended March 31, 2011 and the year ended December 31, 2010 are as follows:

|                               | <i>March 31, 2011</i>        |  | <i>December 31, 2010</i>     |  |
|-------------------------------|------------------------------|--|------------------------------|--|
|                               | <i>Number of<br/>options</i> | <i>Weighted<br/>average<br/>exercise price</i> | <i>Number of<br/>options</i> | <i>Weighted<br/>average<br/>exercise price</i> |
| Outstanding at January 1      | 12,006,232                   | \$ 2.32  | 10,258,756                   | \$ 3.22  |
| Granted during the period     | 295,000                      | 1.19   | 3,950,250                    | 1.06   |
| Exercised during the period   | (60,000)                     | 0.79   | (84,900)                     | 0.79   |
| Expirations during the period | (557,200)                    | 5.03   | (1,430,124)                  | 5.78   |
| Forfeitures during the period | (405,700)                    | 1.05   | (687,750)                    | 1.44   |
| Ending balance                | 11,278,332                   | \$ 2.22  | 12,006,232                   | \$ 2.32  |
| Exercisable, end of period    | 5,533,899                    | \$ 3.39  | 6,111,399                    | \$ 3.53  |

The range of exercise prices of the outstanding options is as follows:

| <i>Range of exercise prices</i> | <i>Number of options</i> | <i>Weighted average<br/>exercise price</i> | <i>Weighted average<br/>remaining life (years)</i> |
|---------------------------------|--------------------------|--|--|
| \$0.79 to \$0.99                | 2,554,300                | \$ 0.79                                    | 3.4  |
| \$1.00 to \$1.50                | 3,824,050                | 1.07                                       | 4.4  |
| \$2.26 to \$3.35                | 673,950                  | 2.68                                       | 2.4  |
| \$3.36 to \$5.00                | 4,122,532                | 4.01                                       | 1.2  |
| \$5.01 to \$6.08                | 103,500                  | 5.22                                       | 0.4  |
| Total at March 31, 2011         | 11,278,332               | \$ 2.22                                    | 2.8  |

### 13. SHARE CAPITAL *(Continued)*

The weighted average share price at the date of exercise for stock options exercised in 2011 was \$1.22 (December 31, 2010 – \$1.02).

The fair value of the options was estimated using the Black-Scholes model with the following weighted average inputs:

|                          | <i>March 31, 2011</i> | <i>March 31, 2010</i> |
|--------------------------|-----------------------|-----------------------|
| Fair value at grant date | \$ 0.61               | \$ 0.68               |
| Share price              | \$ 1.19               | \$ 1.28               |
| Exercise price           | \$ 1.19               | \$ 1.28               |
| Volatility               | 58%                   | 60%                   |
| Option life              | 5 years               | 5 years               |
| Dividends                | 0%                    | 0%                    |
| Risk-free interest rate  | 2.6%                  | 2.3%                  |
| Forfeiture rate          | 15%                   | 15%                   |

This estimated forfeiture rate is adjusted to the actual forfeiture rate when each tranche vests. Stock-based compensation cost of \$0.2 million (March 31, 2010 – \$0.2 million) was expensed during the three months ended March 31 2011. In addition, stock based compensation expense of \$0.1 million (March 31, 2010 – \$0.1 million) was capitalized during the three months ended March 31, 2011.

### 14. LOSS PER SHARE

Basic and diluted loss per share was calculated as follows:

|   | <i>March 31, 2011</i> | <i>March 31, 2010</i> |
|---|-----------------------|-----------------------|
| Loss for the period   | \$ (3,681)            | \$ (44,444)           |
| Weighted average number of common shares (basic)<br><i>(in thousands of shares)</i> |                       |                       |
| Common shares outstanding at January 1  | 172,485               | 150,500               |
| Effect of stock options exercised   | 19                    | -                     |
| Effect of other shares issued   | -                     | 13,311                |
| Weighted average number of common shares (basic)                                    | 172,504               | 163,811               |
| Basic and diluted loss per share  | \$ (0.02)             | \$ (0.27)             |

The average market value of the Company's shares for purposes of calculating the dilutive effect of stock options was based on quoted market prices for the period that the options were outstanding. Excluded from diluted earnings per share is the effect of 11,278,332 options (March 31, 2010 – 10,302,856 options) and 32,258,065 common share reserved for convertible debentures (March 31, 2010 – Nil) as they were anti-dilutive.

### 15. 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 deal 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 deal offering of common shares.

## 16. COMMITMENTS

The Company has entered into an agreement to lease office space until November 30, 2012. Future minimum lease payments are expected to be \$1.4 million in the remainder of 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 third 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 27 million cubic feet per day of gas sales in central Alberta for various terms expiring in one to nine 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<br/>(MMcfd)</i> |    | <i>Committed<br/>amount</i> |
|-------------------|-------------------------------------|----|-----------------------------|
| Remainder of 2011 | 27                                  | \$ | 1,286                       |
| 2012              | 20                                  | \$ | 1,402                       |
| 2013              | 8                                   | \$ | 851                         |
| 2014              | 5                                   | \$ | 678                         |
| 2015              | 4                                   | \$ | 603                         |
| Thereafter        | 12                                  | \$ | 442                         |

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.

## 17. RECONCILIATION FROM CANADIAN GAAP TO IFRS

These are the Company's first interim consolidated financial statements for the period covered by the first annual consolidated financial statements to be prepared in accordance with IFRS.

The accounting policies in note 3 have been applied in preparing the interim consolidated financial statements for the three months ended March 31, 2011, the comparative information presented in these interim consolidated financial statements for both the three months ended March 31, 2010 and the year ended December 31, 2010 and in the preparation of the opening IFRS statement of financial position at January 1, 2010.

Statement of financial position at the date of IFRS transition – January 1, 2010:

| <i>(in thousands of dollars)</i>                   | <i>Canadian<br/>GAAP</i> | <i>Impairment<br/>(note 17b)</i> | <i>Provisions<br/>(note 17d)</i> | <i>Effect of transition to IFRS<br/>Share-<br/>based<br/>payments<br/>(note 17e)</i> | <i>Flow<br/>through<br/>shares<br/>(note 17f)</i> | <i>Deferred<br/>Taxes (note<br/>17h)</i> | <i>IFRS</i>       |
|--|--------------------------|----------------------------------|----------------------------------|--|---|--|-------------------|
| <b>ASSETS</b>                                      |                          |                                  |                                  |  |   |  |                   |
| Current assets:                                    |                          |                                  |                                  |  |   |  |                   |
| Cash and cash equivalents                          | \$ 1                     | \$ -                             | \$ -                             | \$ -   | \$ -  | \$ -                                     | \$ 1              |
| Accounts receivable and<br>accruals                | 22,990                   |                                  |                                  |  |   |  | 22,990            |
| Prepaid expenses and<br>deposits                   | 3,778                    |                                  |                                  |  |   |  | 3,778             |
|  | <u>26,769</u>            | -                                | -                                | -  | -   | -  | <u>26,769</u>     |
| Property, plant and<br>equipment <i>(note 17a)</i> | 470,400                  | (67,193)                         |                                  |  |   |  | 403,207           |
|  | <u>\$ 497,169</u>        | <u>\$ (67,193)</u>               | <u>\$ -</u>                      | <u>\$ -</u>  | <u>\$ -</u>                                       | <u>\$ -</u>                              | <u>\$ 429,976</u> |
| <b>LIABILITIES AND EQUITY</b>                      |                          |                                  |                                  |  |   |  |                   |
| Current liabilities:                               |                          |                                  |                                  |  |   |  |                   |
| Accounts payable and<br>accruals                   | \$ 36,889                | \$ -                             | \$ -                             | \$ -   | \$ -  | \$ -                                     | \$ 36,889         |
| Bank loans   | 62,404                   |                                  |                                  |  |   |  | 62,404            |
| Decommissioning obligations                        | 33,879                   |                                  | 13,778                           |  |   |  | 47,657            |
| Deferred tax liability                             | 31,278                   | (16,914)                         | (3,444)                          |  |   |  | 10,920            |
|  | <u>164,450</u>           | <u>(16,914)</u>                  | <u>10,334</u>                    | -  | -   | -  | <u>157,870</u>    |
| Shareholders' Equity:                              |                          |                                  |                                  |  |   |  |                   |
| Share capital                                      | \$ 391,637               | \$ -                             | \$ -                             | \$ -   | \$ 5,336  | \$ (449)                                 | \$ 396,524        |
| Contributed surplus                                | 6,104                    |                                  |                                  | 234  |   |  | 6,338             |
| Deficit <i>(note 17i)</i>                          | (65,022)                 | (50,279)                         | (10,334)                         | (234)  | (5,336)   | 449                                      | (130,756)         |
|  | <u>332,719</u>           | <u>(50,279)</u>                  | <u>(10,334)</u>                  | <u>-</u>   | <u>-</u>  | <u>-</u>                                 | <u>272,106</u>    |
|  | <u>\$ 497,169</u>        | <u>\$ (67,193)</u>               | <u>\$ -</u>                      | <u>\$ -</u>  | <u>\$ -</u>                                       | <u>\$ -</u>                              | <u>\$ 429,976</u> |

## 17. RECONCILIATION FROM CANADIAN GAAP TO IFRS (Continued)

Statement of financial position at March 31, 2010:

| (in thousands of dollars)                | Canadian<br>GAAP  | Impairment<br>(note 17b) | Provisions<br>(note 17d) | Effect of transition to IFRS              |                         |                                     | Flow<br>through<br>shares<br>(note<br>17f) | Deferred<br>Taxes<br>(note 17h) | IFRS              |
|--|-------------------|--------------------------|--------------------------|---|-------------------------|-------------------------------------|--|---------------------------------|-------------------|
|  |                   |                          |                          | Share-<br>based<br>payments<br>note (17e) | Depletion<br>(note 17c) | Other<br>PP&E<br>adjs<br>(note 17c) |  |                                 |                   |
| <b>ASSETS</b>                            |                   |                          |                          |   |                         |                                     |  |                                 |                   |
| Current assets:                          |                   |                          |                          |   |                         |                                     |  |                                 |                   |
| Cash and cash equivalents                | \$ 1              | \$ -                     | \$ -                     | \$ -                                      | \$ -                    | \$ -                                | \$ -                                       | \$ -                            | \$ 1              |
| Accounts receivable and accruals         | 20,838            |                          |                          |   |                         |                                     |  |                                 | 20,838            |
| Prepaid expenses and deposits            | 3,939             |                          |                          |   |                         |                                     |  |                                 | 3,939             |
|  | <u>24,778</u>     | <u>-</u>                 | <u>-</u>                 | <u>-</u>                                  | <u>-</u>                | <u>-</u>                            | <u>-</u>                                   | <u>-</u>                        | <u>24,778</u>     |
| Property, plant and equipment (note 17a) | 487,118           | (126,733)                | 557                      | (48)                                      | 7,345                   | 589                                 |  |                                 | 368,828           |
|  | <u>\$ 511,896</u> | <u>\$ (126,733)</u>      | <u>\$ 557</u>            | <u>\$ (48)</u>                            | <u>\$ 7,345</u>         | <u>\$ 589</u>                       | <u>\$ -</u>                                | <u>\$ -</u>                     | <u>\$ 393,606</u> |
| <b>LIABILITIES AND EQUITY</b>            |                   |                          |                          |   |                         |                                     |  |                                 |                   |
| Current liabilities:                     |                   |                          |                          |   |                         |                                     |  |                                 |                   |
| Accounts payable and accruals            | \$ 51,706         | \$ -                     | \$ -                     | \$ -                                      | \$ -                    | \$ -                                | \$ -                                       | \$ -                            | \$ 51,706         |
| Current portion of bank loans            | 10,000            |                          |                          |   |                         |                                     |  |                                 | 10,000            |
|  | <u>61,706</u>     | <u>-</u>                 | <u>-</u>                 | <u>-</u>                                  | <u>-</u>                | <u>-</u>                            | <u>-</u>                                   | <u>-</u>                        | <u>61,706</u>     |
| Bank loans                               | 28,825            |                          |                          |   |                         |                                     |  |                                 | 28,825            |
| Decommissioning obligations              | 34,994            |                          | 14,123                   |   |                         | 181                                 |  |                                 | 49,298            |
| Deferred tax liability (asset)           | 28,896            | (31,754)                 | (3,390)                  |   | 1,848                   | (115)                               |  |                                 | (4,515)           |
|  | <u>154,421</u>    | <u>(31,754)</u>          | <u>10,733</u>            | <u>-</u>                                  | <u>1,848</u>            | <u>66</u>                           | <u>-</u>                                   | <u>-</u>                        | <u>135,314</u>    |
| Shareholders' Equity:                    |                   |                          |                          |   |                         |                                     |  |                                 |                   |
| Share capital                            | \$ 421,936        | \$ -                     | \$ -                     | \$ -                                      | \$ -                    | \$ -                                | \$ 5,336                                   | \$ (449)                        | \$ 426,823        |
| Contributed surplus                      | 6,514             |                          |                          | 155                                       |                         |                                     |  |                                 | 6,669             |
| Deficit (note 17i)                       | (70,975)          | (94,979)                 | (10,176)                 | (203)                                     | 5,497                   | 523                                 | (5,336)                                    | 449                             | (175,200)         |
|  | <u>357,475</u>    | <u>(94,979)</u>          | <u>(10,176)</u>          | <u>(48)</u>                               | <u>5,497</u>            | <u>523</u>                          | <u>-</u>                                   | <u>-</u>                        | <u>258,292</u>    |
|  | <u>\$ 511,896</u> | <u>\$ (126,733)</u>      | <u>\$ 557</u>            | <u>\$ (48)</u>                            | <u>\$ 7,345</u>         | <u>\$ 589</u>                       | <u>\$ -</u>                                | <u>\$ -</u>                     | <u>\$ 393,606</u> |

## 17. RECONCILIATION FROM CANADIAN GAAP TO IFRS (Continued)

Statement of financial position at the end of the last reporting year– December 31, 2010:

| <i>(in thousands of dollars)</i>           | Canadian<br>GAAP | Impairment<br>(note 17b) | Decommi-<br>ssioning<br>(note 17d) | Share-<br>based<br>payments<br>note (17e) | Depletion<br>and depre-<br>ciation<br>(note 17c) | Other<br>PP&E<br>adjs<br>(note 17c) | Flow<br>through<br>shares<br>(note<br>17f) | Convert-<br>ible<br>debent-<br>ures<br>(note<br>17g) | Deferred<br>Taxes<br>(note 17h) | IFRS       |
|--|------------------|--------------------------|------------------------------------|---|--|-------------------------------------|--|--|---------------------------------|------------|
| <b>ASSETS</b>                              |                  |                          |                                    |   |  |                                     |  |  |                                 |            |
| Current assets:                            |                  |                          |                                    |   |  |                                     |  |  |                                 |            |
| Cash and cash equivalents                  | \$ 4,024         | \$ -                     | \$ -                               | \$ -                                      | \$ -   | \$ -                                | \$ -                                       | \$ -   | \$ -                            | \$ 4,024   |
| Accounts receivable and accruals           | 20,998           |                          |                                    |   |  |                                     |  |  |                                 | 20,998     |
| Prepaid expenses and deposits              | 3,052            |                          |                                    |   |  |                                     |  |  |                                 | 3,052      |
| Deferred tax asset - current               | 508              |                          |                                    |   |  |                                     |  |  | (508)                           | -          |
|  | 28,582           | -                        | -                                  | -   | -  | -                                   | -  | -  | (508)                           | 28,074     |
| Property, plant and equipment (note 17a)   | 506,533          | (220,358)                | 2,185                              | (322)                                     | 33,071   | (435)                               |  |  |                                 | 320,674    |
|  | \$ 535,115       | \$ (220,358)             | \$ 2,185                           | \$ (322)                                  | \$ 33,071  | \$ (435)                            | \$ -                                       | \$ -   | \$ (508)                        | \$ 348,748 |
| <b>LIABILITIES AND EQUITY</b>              |                  |                          |                                    |   |  |                                     |  |  |                                 |            |
| Current liabilities:                       |                  |                          |                                    |   |  |                                     |  |  |                                 |            |
| Accounts payable and accruals              | \$ 46,862        | \$ -                     | \$ -                               | \$ -                                      | \$ -   | \$ -                                | \$ -                                       | \$ -   | \$ -                            | \$ 46,862  |
| Unrealized loss on derivative contracts    | 1,918            |                          |                                    |   |  |                                     |  |  |                                 | 1,918      |
|  | 48,780           | -                        | -                                  | -   | -  | -                                   | -  | -  | -                               | 48,780     |
| Bank loans                                 | 52,719           |                          |                                    |   |  |                                     |  |  |                                 | 52,719     |
| Convertible debentures                     | 43,460           |                          |                                    |   |  |                                     |  |  |                                 | 43,460     |
| Decommissioning obligations                | 36,320           |                          | 15,075                             |   |  | 155                                 |  |  |                                 | 51,550     |
| Deferred tax liability (asset)             | 20,045           | (55,407)                 | (3,222)                            |   | 8,268  | (482)                               |  | 1,650  | (508)                           | (29,656)   |
|  | 201,324          | (55,407)                 | 11,853                             | -   | 8,268  | (327)                               | -  | 1,650  | (508)                           | 166,853    |
| Shareholders' Equity:                      |                  |                          |                                    |   |  |                                     |  |  |                                 |            |
| Share capital                              | \$ 422,038       | \$ -                     | \$ -                               | \$ -                                      | \$ -   | \$ -                                | \$ 5,336                                   | \$ -   | \$ (449)                        | \$ 426,925 |
| Equity component of convertible debentures | 4,242            |                          |                                    |   |  |                                     | (1,650)                                    |  |                                 | 2,592      |
| Contributed surplus                        | 8,164            |                          |                                    | (243)                                     |  |                                     |  |  |                                 | 7,921      |
| Deficit (note 17i)                         | (100,653)        | (164,951)                | (9,668)                            | (79)                                      | 24,803   | (108)                               | (5,336)                                    | -  | 449                             | (255,543)  |
|  | 333,791          | (164,951)                | (9,668)                            | (322)                                     | 24,803   | (108)                               | -  | (1,650)  | -                               | 181,895    |
|  | \$ 535,115       | \$ (220,358)             | \$ 2,185                           | \$ (322)                                  | \$ 33,071  | \$ (435)                            | \$ -                                       | \$ -   | \$ (508)                        | \$ 348,748 |

## 17. RECONCILIATION FROM CANADIAN GAAP TO IFRS (Continued)

Reconciliation of consolidated statement of operations and comprehensive loss for the three months ended March 31, 2010:

| (in thousands of dollars)  | Canadian<br>GAAP | Impairment<br>(note 17b) | Effect of transition to IFRS       |   |  |        | Other<br>PP&E<br>adjs<br>(note 17c) | IFRS        |
|--|------------------|--------------------------|------------------------------------|---|--|--------|-------------------------------------|-------------|
|  |                  |                          | Decommi-<br>ssioning<br>(note 17d) | Share-<br>based<br>payments<br>(note 17e) | Depletion<br>and<br>depreciation<br>(note 17c) |        |                                     |             |
| Oil and gas sales  | \$ 23,265        | \$ -                     | \$ -                               | \$ -                                      | \$ -   | \$ -   | \$ -                                | \$ 23,265   |
| Royalties  | (3,394)          |                          |                                    |   |  |        |                                     | (3,394)     |
| Revenue, net of royalties  | 19,871           | -                        | -                                  | -   | -  | -      | -                                   | 19,871      |
| Gain on sale of property, plant<br>and equipment                               | -                |                          |                                    |   |  | 673    | 673                                 | 673         |
|  | 19,871           | -                        | -                                  | -   | -  | 673    | 673                                 | 20,544      |
| Operating expenses   | 6,876            |                          |                                    |   |  |        |                                     | 6,876       |
| Depletion and depreciation   | 17,689           |                          |                                    |   | (7,345)  |        |                                     | 10,344      |
| Impairment of property, plant and<br>equipment                                 | -                | 59,540                   |                                    |   |  |        |                                     | 59,540      |
| General and administrative<br>expenses, including stock-<br>based compensation | 1,943            |                          |                                    | (31)                                      |  | 200    | 200                                 | 2,112       |
| Loss from operating activities   | (6,637)          | (59,540)                 | -                                  | 31  | 7,345  | 473    | 473                                 | (58,328)    |
| Finance income   | 58               |                          |                                    |   |  |        |                                     | 58          |
| Finance expenses, including<br>accretion                                       | (1,313)          |                          | 211                                |   |  |        |                                     | (1,102)     |
| Net finance expenses   | (1,255)          | -                        | 211                                | -   | -  | -      | -                                   | (1,044)     |
| Loss before taxes  | (7,892)          | (59,540)                 | 211                                | 31  | 7,345  | 473    | 473                                 | (59,372)    |
| Deferred income tax reduction  | (1,939)          | (14,840)                 | 53                                 | -   | 1,848  | (50)   | (50)                                | (14,928)    |
| Loss and comprehensive loss for<br>the period                                  | \$ (5,953)       | \$ (44,700)              | \$ 158                             | \$ 31                                     | \$ 5,497                                       | \$ 523 | \$ 523                              | \$ (44,444) |

## 17. RECONCILIATION FROM CANADIAN GAAP TO IFRS (Continued)

Reconciliation of consolidated statement of operations and comprehensive loss for the year ended December 31, 2010:

| <i>(in thousands of dollars)</i>  | Canadian<br>GAAP | Impairment<br>(note 17b) | Decommi-<br>ssioning<br>(note 17d) | Share-<br>based<br>payments<br>(note 17e) | Depletion<br>and<br>depreciation<br>(note 17c) | Other<br>PP&E adjs<br>(note 17c) | IFRS         |
|---|------------------|--------------------------|------------------------------------|---|--|----------------------------------|--------------|
| Oil and gas sales   | \$ 86,457        | \$ -                     | \$ -                               | \$ -                                      | \$ -   | \$ -                             | \$ 86,457    |
| Royalties   | (9,011)          |                          |                                    |   |  |                                  | (9,011)      |
| Revenue, net of royalties   | 77,446           | -                        | -                                  | -   | -  | -                                | 77,446       |
| Realized loss on derivative contracts                                   | (131)            |                          |                                    |   |  |                                  | (131)        |
| Unrealized loss on derivative contracts                                 | (1,918)          |                          |                                    |   |  |                                  | (1,918)      |
| Gain on sale of property, plant and equipment                           | -                |                          |                                    |   |  | 389                              | 389          |
|   | 75,397           | -                        | -                                  | -   | -  | 389                              | 75,786       |
| Operating expenses  | 29,148           |                          |                                    |   |  |                                  | 29,148       |
| Depletion and depreciation  | 78,723           |                          |                                    |   | (33,071)                                       |                                  | 45,652       |
| Impairment of property, plant and equipment                             | -                | 153,165                  |                                    |   |  |                                  | 153,165      |
| General and administrative expenses, including stock-based compensation | 8,908            |                          |                                    | (155)                                     |  | 664                              | 9,417        |
| Loss from operating activities  | (41,382)         | (153,165)                | -                                  | 155                                       | 33,071   | (275)                            | (161,596)    |
| Finance income  | 96               |                          |                                    |   |  |                                  | 96           |
| Finance expenses, including accretion                                   | (5,894)          |                          | 888                                |   |  |                                  | (5,006)      |
| Net finance expenses  | (5,798)          | -                        | 888                                | -   | -  | -                                | (4,910)      |
| Loss before taxes   | (47,180)         | (153,165)                | 888                                | 155                                       | 33,071   | (275)                            | (166,506)    |
| Deferred income tax reduction   | (11,549)         | (38,495)                 | 223                                | -   | 8,268  | (166)                            | (41,719)     |
| Loss and comprehensive loss for the year                                | \$ (35,631)      | \$ (114,670)             | \$ 665                             | \$ 155                                    | \$ 24,803                                      | \$ (109)                         | \$ (124,787) |

## 17. RECONCILIATION FROM CANADIAN GAAP TO IFRS (Continued)

### Notes to reconciliations

(a) *IFRS 1 – Deemed Cost.* The Company applied the IFRS 1 exemption whereby the value of its opening plant, property and equipment at January 1, 2010 was deemed to be equal to the net book value as determined under Canadian GAAP and the corresponding CGUs were tested for impairment. The Company chose to allocate its costs to its CGUs based on proved plus probable reserves volumes.

(b) *IAS 36 Adjustments – Impairment of Assets.* Under Canadian GAAP, impairment of non-financial assets is assessed on the basis of an asset's estimated undiscounted future cash flows compared with the asset's carrying amount and if impairment is indicated, discounted cash flows are prepared to quantify the amount of the impairment. Under IFRS, impairment is assessed based on recoverable amount (greater of value in use or fair value less costs to sell) compared with the asset's carrying amount to determine the recoverable amount and measure the amount of the impairment. In addition, under IFRS, where a non-financial assets does not generate largely independent cash inflows, the Company is required to perform its test at a cash generating unit level, which is the smallest identifiable grouping of assets that generates largely independent cash inflows. Canadian GAAP impairment is based on undiscounted cash flows using asset groupings with both independent cash inflows and cash outflows.

As a result of this impairment testing at a cash generating unit level, the Company recognized an impairment of \$67.2 million at January 1, 2010 with a corresponding reduction to retained earnings. For the three months ended March 31, 2010 and the year ended December 31, 2010 the Company recognized additional impairments of \$59.5 million and \$153.2 million respectively with a corresponding reduction in property, plant and equipment as a result of declines in the forward natural gas price curves.

(c) *IAS 16 Adjustments – Property, Plant and Equipment.*

*Depletion and depreciation.* Upon transition to IFRS, the Company adopted a policy of depleting and depreciating oil and natural gas interests on a unit of production basis over proved plus probable reserves. The depletion and depreciation policy under Canadian GAAP was based on units of production over proved reserves. In addition, depletion and depreciation was calculated on the Canadian full cost pool under Canadian GAAP. IFRS requires depletion and depreciation to be calculated based on individual components

There was no impact of this difference on adoption of IFRS at January 1, 2010 as a result of the policy as discussed above. For the three months ended March 31, 2010, the use of proved plus probable reserves as well as the lower net book value due to the transition impairment of the Company's Shallow Gas CGU resulted in a decrease to depletion of \$7.3 million (year ended December 31, 2010 – \$33.1 million) with a corresponding increase to property, plant and equipment.

*Other adjustments.* IFRS requires that gains or losses be reported on the disposition of property, plant and equipment. Under Canadian GAAP, gains or losses on disposition of property, plant and equipment were only reported when the disposition resulted in more than a 20 percent change in the depletion rate. As a result of this requirement, the Company reported a gain of \$0.7 million during the three months ended March 31, 2010 (year ended December 31, 2010 – \$0.4 million) with an increase in property, plant and equipment where the proceeds were originally recorded under Canadian GAAP and a net increase to decommissioning obligations that were assumed as part of an asset exchange of \$0.2 million (year ended December 31, 2010 – \$0.2 million).

## 17. RECONCILIATION FROM CANADIAN GAAP TO IFRS *(Continued)*

IFRS also requires that the capitalization of general and administrative costs be limited to directly attributable costs. Under Canadian GAAP, a reasonable allocation of general and administrative costs to property, plant and equipment was acceptable. As a result of the change in the capitalization criteria, the Company increased its general and administrative expense by \$0.2 million during the three months ended March 31, 2010 (year ended December 31, 2010 – \$0.7 million) with a corresponding decrease in property, plant and equipment.

Under Canadian GAAP, a deferred tax adjustment was recorded related to stock-based compensation costs capitalized. No such adjustment is made under IFRS. As a result of this change, property, plant and equipment was reduced by \$0.1 million at March 31, 2010 (\$0.3 million at December 31, 2010) with a corresponding decrease to the deferred tax liability.

*(d) IAS 37 Adjustments – Provisions, Contingent Liabilities and Contingent Assets.* Consistent with IFRS, decommissioning obligations (asset retirement obligations under Canadian GAAP) were measured under Canadian GAAP based on the estimated cost of decommissioning, discounted to their net present value upon initial recognition. Under Canadian GAAP, asset retirement obligations were discounted at a credit adjusted risk free rate of eight to 10 percent. Under IFRS, the estimated cash flow to abandon and remediate the wells and facilities has been risk adjusted, therefore the provision is discounted at a risk free rate of one to four percent. Decommissioning obligations are also required to be re-measured based on changes in estimates including discount rates.

The IFRS 1 exemption was utilized for asset retirement obligations associated with oil and gas properties and the Company re-measured asset retirement obligations as at January 1, 2010 under IAS 37 with a corresponding adjustment to opening retained earnings. Upon transition to IFRS this resulted in a \$13.8 million increase in the decommissioning obligations with a corresponding decrease in retained earnings.

At March 31, 2010, using risk-free rates of one to four percent, depending on the estimated timing of the future obligation, the Company increased its decommissioning obligations by \$14.1 million (December 31, 2010 – \$15.1 million) from Canadian GAAP. The Company also increased the value of its plant, property and equipment for March 31, 2010 and December 31, 2010 by \$0.6 million and \$2.2 million respectively.

As a result of the change in the decommissioning obligation, accretion expense decreased by \$0.2 million during the three months ended March 31, 2010 (December 31, 2010 – \$0.9 million) under IFRS compared to Canadian GAAP. In addition, under Canadian GAAP accretion of the discount was included in depletion and depreciation. Under IFRS, it is included in finance expenses.

*(e) IFRS 2 Adjustments – Share-based Payments.* Under Canadian GAAP, the Company recognized an expense related to stock-based compensation on a straight-line basis through the date of full vesting and incorporated a forfeiture multiple, which was optional under Canadian GAAP. Under IFRS, the Company is required to recognize the expense over the individual vesting periods for the graded vesting awards and estimate a forfeiture rate. Upon transition to IFRS, this resulted in a \$0.2 million increase in contributed surplus with a corresponding decrease in retained earnings. For the three months ended March 31, 2010, the Company reduced the amount of stock-based compensation expense by \$31,000 (year ended December 31, 2010 – \$0.2 million). In addition, under Canadian GAAP, stock-based compensation was disclosed separately on the consolidated statement of operations and comprehensive loss. Under IFRS, stock-based compensation is included in general and administrative expenses.

## 17. RECONCILIATION FROM CANADIAN GAAP TO IFRS (Continued)

(f) *Flow Through Shares.* Under Canadian GAAP, the Company recorded the deferred tax impact on renouncement of flow through shares against share capital. Under IFRS, the Company is required to record a premium liability when the flow through shares are issued, which is relieved upon renouncement, with the difference going to deferred tax expense. As a result of this change in the treatment of deferred taxes, at transition, the Company recorded an additional \$5.3 million to share capital with a corresponding reduction in retained earnings for flow through shares that had been previously issued and fully renounced at transition.

(g) *Convertible Debentures.* Under Canadian GAAP, the Company did not record a deferred tax difference on its convertible debentures. Under IFRS, the Company is required to record the deferred tax difference between the fair value of the liability component of the convertible debentures and the tax value of the convertible debentures with the difference being booked against the equity component of convertible debentures.

(h) *IAS 12 Adjustments – Income Taxes.* The aforementioned changes increased (decreased) the net deferred tax liability as follows based on a tax rate of 25 percent:

|  | December 31,<br>2010 | March 31,<br>2010  | January 1,<br>2010 |
|--|----------------------|--------------------|--------------------|
| Impairment of plant, property and equipment<br><i>(note 17b)</i> | \$ (55,407)          | \$ (31,754)        | \$ (16,914)        |
| Depletion and depreciation <i>(note 17c)</i>                     | 8,268                | 1,848              | -                  |
| Decommissioning obligation <i>(note 17d)</i>                     | (3,222)              | (3,390)            | (3,444)            |
| Convertible debentures <i>(note 17g)</i>                         | 1,650                | -                  | -                  |
| Other adjustments <i>(note 17c)</i>                              | (482)                | (115)              | -                  |
| <b>Decrease in deferred tax liabilities</b>                      | <b>\$ (49,193)</b>   | <b>\$ (33,411)</b> | <b>\$ (20,358)</b> |

IFRS requires that adjustments to the future tax rates used to calculate deferred taxes be traced and recorded against the original source of the timing difference as opposed to through earnings as was done under Canadian GAAP. As a result of this change at January 1, 2010, the Company reclassified \$0.5 million in deferred taxes previously recorded in income against share issue costs.

Under Canadian GAAP, the Company was required to present its future income tax assets and liabilities in the same current and long-term classification from which the timing differences arose. There is no such requirement under IFRS, therefore the Company reclassified \$0.5 million at December 31, 2010 from current future income tax assets to the deferred tax asset.

The effect on the consolidated statements of operations and comprehensive loss for the three months ended March 31, 2010 and the year ended December 31, 2010 was to decrease the previously reported tax charge for the period by \$13.0 million and \$30.2 million, respectively.

## 17. RECONCILIATION FROM CANADIAN GAAP TO IFRS (Continued)

(i) *Opening Retained Earnings Adjustments.* The aforementioned changes increased (decreased) increased retained earnings as follows on an after-tax basis:

|   | December 31,<br>2010 | March 31,<br>2010   | January 1,<br>2010 |
|---|----------------------|---------------------|--------------------|
| Impairment of plant, property and equipment<br>(note 17b)   | \$ (164,951)         | \$ (94,979)         | \$ (50,279)        |
| Decommissioning obligations (note 17d)                      | (9,668)              | (10,176)            | (10,334)           |
| Flow through shares (note 17f)                              | (5,336)              | (5,336)             | (5,336)            |
| Depletion and depreciation (note 17c)                       | 24,803               | 5,497               | -                  |
| Gain on sale of plant, property and<br>equipment (note 17c) | 389                  | 673                 | -                  |
| Deferred taxes on share issue costs (note 17h)              | 449                  | 449                 | 449                |
| General and administrative expenses<br>(note 17c)           | (497)                | (150)               | -                  |
| Stock-based compensation (note 17e)                         | (79)                 | (203)               | (234)              |
| <b>Decrease in retained earnings</b>                        | <b>\$ (154,890)</b>  | <b>\$ (104,225)</b> | <b>\$ (65,734)</b> |

(j) *Adjustments to the Company's Cash Flow Statement under IFRS.* The reconciling items discussed above between Canadian GAAP and IFRS policies have no material impact on the cash flows generated by the Company. As a result of the change in capitalized general and administrative expenses, there was a reduction of \$0.2 million to operating cash flows, with an equal and opposite effect on investing cash flows for the three months ended March 31, 2010 and \$0.7 million for the year ended December 31, 2010.

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(2) Compensation & Corporate  
Governance Committee  
(3) Reserves Committee

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### 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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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  
Mstb – thousand stock tank barrels  
BOE – barrels of oil equivalent  
BOED – barrels of oil equivalent per day  
BOPD – barrels of oil per day  
MBOE – thousand barrels of oil equivalent  
GJ – gigajoule  
Mcf – thousand cubic feet  
Mcf/d – thousand cubic feet per day  
MMcf – million cubic feet  
MMcf/d – million cubic feet per day  
NGL – natural gas liquids  
WTI – West Texas Intermediate