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## Anderson Energy Announces 2011 Second Quarter Results

Calgary, Alberta, August 15, 2011 - Anderson Energy Ltd. ("Anderson Energy" or the "Company") (TSX:AXL) is pleased to announce its operating and financial results for the three and six months ended June 30, 2011.

### HIGHLIGHTS:

- Funds from operations in the second quarter were \$13.9 million, up 56% from the second quarter of 2010 and 28% from the first quarter of 2011.
- Total production was 7,758 BOED in the second quarter of 2011 compared to 7,732 BOED in the second quarter of 2010. Oil and NGL production in the second quarter averaged 2,426 bpd, up 97% from the second quarter of 2010 and 17% from the 2,071 bpd reported in the first quarter of 2011. Oil represented 1,759 bpd of total production in the second quarter and was 258% higher than the second quarter of 2010 and 28% higher than the first quarter of 2011.
- Oil and NGL revenue made up 65% of total oil and gas sales in the second quarter of 2011.
- Earnings were \$5.9 million in the second quarter of 2011.
- The operating netback improved to \$25.47 per BOE in the second quarter of 2011 from \$16.58 per BOE in the second quarter of 2010, due to increased oil volumes and higher oil and NGL prices.
- The capital program for 2011 is estimated to be \$115 million. Production guidance associated with this 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) were drilled in the first half of 2011 and nine gross (7.0 net) Cardium horizontal oil wells have been drilled in the third quarter to date. The Company currently has five drilling rigs working in the field drilling Cardium horizontal oil wells.
- On June 8, 2011, the Company closed a \$46 million convertible debenture bought deal offering.
- 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.
- Drill ready Cardium horizontal oil location inventory stands at 213 gross (128.6 net) locations, a 51% increase since December 31, 2010 and an 11% increase since the May 16, 2011 press release. The Company has increased the Cardium prospective land that it owns or controls by 23% since December 31, 2010 to 124.5 gross (73.7 net) sections (85% in the oil fairway). Using an industry standard disclosure of three wells per section drilling density, the drilling inventory would be 221 net locations.

## FINANCIAL AND OPERATING HIGHLIGHTS

<i>(thousands of dollars, unless otherwise stated)</i>	<i>Three months ended June 30</i>			<i>Six months ended June 30</i>		
	<i>2011</i>	<i>2010*</i>	<i>% Change</i>	<i>2011</i>	<i>2010*</i>	<i>% Change</i>
Oil and gas sales**	\$ 31,566	\$ 20,318	55%	\$ 57,152	\$ 43,583	31%
Revenue, net of royalties**	\$ 27,776	\$ 18,622	49%	\$ 51,059	\$ 38,493	33%
Funds from operations	\$ 13,944	\$ 8,923	56%	\$ 24,812	\$ 19,358	28%
Funds from operations per share						
Basic and diluted	\$ 0.08	\$ 0.05	60%	\$ 0.14	\$ 0.12	17%
Earnings (loss) before effect of impairment	\$ 5,932	\$ (2,450)	342%	\$ 2,251	\$ (2,194)	203%
Earnings (loss) per share before effect of impairment						
Basic and diluted	\$ 0.03	\$ (0.01)	400%	\$ 0.01	\$ (0.01)	200%
Earnings (loss)	\$ 5,932	\$ (4,769)	224%	\$ 2,251	\$ (49,213)	105%
Earnings (loss) per share						
Basic and diluted	\$ 0.03	\$ (0.03)	200%	\$ 0.01	\$ (0.29)	103%
Capital expenditures, including acquisitions net of dispositions	\$ 26,284	\$ 12,664	108%	\$ 68,638	\$ 45,891	50%
Bank loans plus cash working capital deficiency				\$ 71,464	\$ 70,284	2%
Convertible debentures				\$ 83,872	\$ -	100%
Shareholders' equity				\$ 187,401	\$ 253,903	(26%)
Average shares outstanding <i>(thousands)</i>						
Basic	172,548	172,400	-	172,526	168,129	3%
Diluted	172,935	172,400	-	173,163	168,129	3%
Ending shares outstanding <i>(thousands)</i>				172,550	172,400	-
Average daily sales:						
Natural gas <i>(Mcf)</i>	31,990	38,998	(18%)	32,955	37,120	(11%)
Oil <i>(bpd)</i>	1,759	491	258%	1,567	419	274%
NGL <i>(bpd)</i>	667	741	(10%)	683	763	(10%)
Barrels of oil equivalent <i>(BOED)</i>	7,758	7,732	-	7,742	7,368	5%
Average prices:						
Natural gas <i>(\$/Mcf)</i>	\$ 3.79	\$ 3.78	-	\$ 3.68	\$ 4.46	(17%)
Oil <i>(\$/bbl)</i>	\$ 99.39	\$ 70.45	41%	\$ 93.00	\$ 72.51	28%
NGL <i>(\$/bbl)</i>	\$ 74.24	\$ 53.55	39%	\$ 70.03	\$ 55.15	27%
Barrels of oil equivalent <i>(\$/BOE)**</i>	\$ 44.71	\$ 28.88	55%	\$ 40.78	\$ 32.68	25%
Realized loss on derivative contracts <i>(\$/BOE)</i>	\$ 1.17	\$ -	(100%)	\$ 0.87	\$ -	(100%)
Royalties <i>(\$/BOE)</i>	\$ 5.37	\$ 2.41	123%	\$ 4.35	\$ 3.82	14%
Operating costs <i>(\$/BOE)</i>	\$ 12.04	\$ 9.71	24%	\$ 11.34	\$ 10.21	11%
Transportation costs <i>(\$/BOE)</i>	\$ 0.66	\$ 0.18	267%	\$ 0.50	\$ 0.16	213%
Operating netback <i>(\$/BOE)</i>	\$ 25.47	\$ 16.58	54%	\$ 23.72	\$ 18.49	28%
Wells drilled <i>(gross)</i>	5	3	67%	20	29	(31%)

\* 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 second quarter of 2011, four gross (2.5 net revenue) Cardium horizontal oil wells were drilled. From May 1, 2010 to June 30, 2011, the Company has placed 41 gross (29.2 net) Cardium oil wells on production. Oil and NGL production for the three months ended June 30, 2011 was 2,426 bpd, up substantially from 1,232 bpd in the second quarter of 2010. Of this number, 1,759 bpd or 73% is crude oil production, compared to 491 bpd or 40% in the second 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 August 15, 2011	50	36.2	42	30.2
Estimated up to December 31, 2011	66	44.0	66	44.0

*"Net" is net revenue interest earned.*

The Company currently has five drilling rigs working in the field drilling horizontal oil wells. As of August 15, 2011, nine gross (7.0 net) Cardium horizontal oil wells have been drilled in the third quarter and six of them have been completed.

The Company's Cardium prospective land inventory is 124.5 gross (73.7 net) sections, an increase of 8% since the last update on May 16, 2011 and 23% since December 31, 2010. 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 213 gross (128.6 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 11% since the May 16, 2011 press release. The Company has not included prospective locations from the gas prone fairway as natural gas prices are low. 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 now conducts 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 to be approximately \$2.6 million per well in the Garrington field and \$3.0 to \$3.2 million per well in other properties.

The Garrington battery consolidation project was completed in early August with all of the Company's single well batteries connected to the central 15-34 tank battery. This project is expected to reduce operating and capital costs in this area. The 100% owned facility will ultimately be connected by Plains Midstream Canada to the Rangeland Pipeline system later this year. This facility is processing third party volumes and so also represents an attractive source of processing fee income for the Company.

The Company is 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 identified five non-Cardium zones on its lands in central Alberta, with potential for horizontal oil drilling. These zones are Second White Specs, Belly River, Viking, Glauconite and Mannville. The first Belly River horizontal oil well is scheduled to be drilled in the fourth quarter of 2011 and the Company is evaluating the timeline to drill the other four horizons later in 2011 or in 2012.

## PRODUCTION

For the second quarter of 2011, the Company averaged 7,758 BOED, with oil and NGL volumes representing 31% of total volumes. Oil and NGL production is 17% higher than the first quarter of 2011 due to increasing Cardium oil volumes. The Company experienced very wet weather in the latter part of the second quarter of 2011, which negatively impacted production volumes, drilling and completion activity and operating costs.

In the third quarter of 2011, the Company's production will be negatively impacted by a planned major one month plant turnaround at Buck Lake, which represents 500 BOED of production, for the duration of the turnaround.

## FINANCIAL RESULTS

Capital expenditures, net of proceeds on dispositions, were \$26.3 million in the second quarter of 2011 with \$12.7 million spent on drilling and completions and \$9.5 million spent on facilities. This compares to capital expenditures of \$12.7 million in the second quarter of 2010. As of August 15, 2011, the Company has disposed of \$12.6 million in property sales and sales of excess drilling royalty credits as compared to its original budget of \$10 million.

The Company's funds from operations were \$13.9 million in the second quarter of 2011 compared to \$8.9 million in the second quarter of 2010. The Company's average crude oil and natural gas liquids sales price in the second quarter of 2011 was \$92.48 per barrel compared to \$60.28 per barrel in the second quarter of 2010. The Company realized a loss of \$0.8 million on WTI Canadian fixed price oil contracts in the second quarter of 2011, which negatively impacted funds from operations. The Company has entered into fixed price oil swaps for 2011 and 2012. The WTI Canadian prices on these contracts range between \$88.45 per bbl to \$107.00 per bbl. The Company's mark to market valuation of its oil hedge gain at June 30, 2011 is \$2.9 million. The Company's average natural gas sales price was \$3.79 per Mcf in the second quarter of 2011 compared to \$3.78 per Mcf in second quarter of 2010. The Company entered into physical contracts to sell 15,000 GJ per day of natural gas at an average AECO gas price of \$4.06 per GJ for the period July 1 to October 31, 2011. This equates to approximately 13.9 MMcfd at an average plant gate price of approximately \$4.15 per Mcf. The Company recorded earnings of \$5.9 million in the second quarter of 2011 primarily due to the hedging gain and a stronger contribution to total revenue by additional oil volumes and higher oil and NGL prices. The Company's operating netback was \$25.47 per BOE in the second quarter of 2011 compared to \$16.58 per BOE in the second quarter of 2010. The increase in the operating netback was primarily due to the increase in oil and NGL prices and oil volumes.

	<i>Average wellhead natural gas price (\$/Mcf)</i>	<i>Revenue (\$/BOE)</i>	<i>Operating netback (\$/BOE)</i>	<i>Funds from operations (\$/BOE)</i>
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
Second quarter of 2011	3.79	44.71	25.47	19.75
First quarter of 2012 estimate (\$90 to \$100 WTI Canadian** plus oil hedge program)	4.00**	48.00 to 50.00	33.00 to 36.00	25.00 to 28.00

\* 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, operating netback per BOE and funds from operations per BOE should increase and as a consequence, the Company expects to reposition itself to achieve sustained profitability by 2012. Royalties were \$5.37 per BOE in the second quarter of 2011 compared to \$3.31 per BOE in the first quarter of 2011 due to annual gas cost allowance adjustments recorded in the second quarter. Operating expenses in the second quarter of 2011 were \$12.04 per BOE, which was 13% higher than the first quarter of 2011 due to costs associated with temporary production facilities being utilized for longer periods of time as a result of spring breakup and extremely wet weather. These costs negatively impacted operating expenses in the second quarter by \$0.78 per BOE. After adjusting for temporary production facility costs in the second quarter, operating costs were 6% higher than in the first quarter of 2011. These facilities are now permanently connected to the new Garrington battery consolidation project and to a permanent battery installation in Willesden Green.

## FINANCING

On June 8, 2011, the Company completed a \$46 million convertible subordinated debenture financing. The debentures have a six year term with a 7.25% coupon and a conversion price of \$1.70 per share. Proceeds were initially used to reduce the Company's bank indebtedness and provide financial flexibility for its 2011 capital program. As of June 30, 2011, 65% of the Company's debt is long term convertible debenture financing and the remainder is extendible revolving term bank debt.

In the second quarter of 2011, the Company sold \$626,000 in properties and surplus drilling royalty credits. As of August 15, 2011, the Company has sold a total of \$12.6 million in properties and surplus drilling royalty credits in 2011, which is higher than the budget plan of \$10 million. The Company is financing its drilling program with bank loans, convertible debentures, cash flow and dispositions in 2011. On May 13, 2011, the Company entered into an agreement with a syndicate of three Canadian banks to renew its credit facilities and increase the total facilities to \$135 million. As of June 30, 2011, the Company had drawn down 34% of these facilities.

## 2011 CAPITAL PROGRAM

During the second quarter of 2011, the Company's Board of Directors approved an increase in the capital program from \$75 million to \$115 million. The increase in 2011 capital spending is back-end weighted. 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) had been drilled to June 30, 2011. The Company is planning to drill one Belly River well in the fourth quarter of 2011, and is evaluating the other four non-Cardium zones for horizontal oil drilling in the latter part of 2011 or in 2012.

## COMMODITY CONTRACTS

*Crude Oil.* 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 for volumes and prices for these contracts is summarized below:

<i>Period</i>	<i>Weighted average volume (bbls)</i>	<i>Weighted average WTI Canadian (\$/bbl)</i>
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 Company entered into the hedging contracts to protect its capital program and support its bank borrowing base. 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.

The mark to market hedge gain as of June 30, 2011 was \$2.9 million for the crude oil contracts.

*Natural Gas.* The Company has physically contracted to sell 15,000 GJ per day of natural gas at an average Canadian dollar AECO price of \$4.06 per GJ, from July 1, 2011 to October 31, 2011. This equates to approximately 13.9 MMcfd at an average plant gate price of approximately \$4.15 per Mcf.

## STRATEGY

At WTI Canadian oil prices of \$85 per bbl, operating netbacks in the Cardium program are approximately \$62 per BOE as compared to operating netbacks in the Edmonton Sands shallow gas program of \$15 per BOE. A change in WTI Canadian oil price of \$5 per bbl, would impact the Cardium operating netback by \$4.36 per BOE. The Company estimates it could grow its oil and NGL production from 18% of total production in 2010 to 33% in 2011 and estimates that it will have balanced its gas production with oil and NGL production by sometime in 2012. Independent analysts currently estimate that funds from operations (or "cash flow") will range from \$47 million to \$62 million in 2011 and \$73 million to \$98 million in 2012, which is significant growth when compared to \$36.5 million in funds from operations in 2010. Management believes that a strategy of cash flow growth through light oil horizontal drilling is the best solution in this period of anemic natural gas prices. As part of this transition from natural gas to oil, the Company completed two convertible debenture financings with five to six year terms and conversion prices of \$1.55 and \$1.70 per share. This provides the Company with better financial flexibility to make the transformation to a balanced oil and gas producer. Debt leverage is higher than some of its peers in 2011, however, with improving revenue from oil production in 2011 and 2012, leverage is

expected to return to more typical levels for junior oil producers by 2012. The Company believes it has the depth of prospects to stay the oil course and still bring forward natural gas prospects for drilling when economic conditions dictate.

With oil prices at or near present levels, we expect to be able to finance our foreseeable drilling programs out of cash flow and currently available credit facilities without the need for external financing.

In the last year, we were able to move up the learning curve in the Cardium play with 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.

## OUTLOOK

Oil prices continue to be strong, but volatile, and are expected to remain so in the near term. Natural gas prices are weak and the timing of natural gas price recovery to economic levels is uncertain. The Company will continue to dedicate its capital program to light oil horizontal oil drilling as these prospects represent the best economics.

By the end of 2011, the Company estimates it will have 44 net revenue Cardium horizontal wells on production, up 50% from the end of the second quarter 2011. The Company has increased its Cardium development drilling inventory by 51% since December 31, 2010 and is becoming one of the industry leaders in lowering Cardium capital costs. The Company believes it is well positioned in the Cardium horizontal oil play and the results from the Cardium program will help to peel the natural gas label off the stock price and reward shareholders with more of an oil company valuation. As oil production grows in 2011, the impact that this currently higher priced commodity will have on its cash flow and earnings could be significant.

We have five drilling rigs currently active in the field, drilling Cardium horizontal oil wells. Additional horizontal oil prospectivity have been identified in the Second White Specs, Viking, Belly River, Glauconite and Mannville formations. Some of these zones are expected to be advanced for drilling in the fourth quarter of 2011.

In the second quarter of 2011, the Company achieved significant increases in operating netback and funds from operations per BOE and recorded positive earnings as a result of hedging gains and the doubling its oil and NGL production compared to the second quarter of 2010. This is the first quarter that we have started to see the benefits of the strategy change to light oil horizontal drilling. With the emphasis on oil drilling, the Company could potentially see its oil and natural gas production becoming balanced sometime in 2012. For more information, we encourage investors to review our website at [www.andersonenergy.ca](http://www.andersonenergy.ca).

Brian H. Dau  
President & Chief Executive Officer  
August 15, 2011

## Management's Discussion and Analysis

FOR THE THREE AND SIX MONTHS ENDED JUNE 30, 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 and six months ended June 30, 2011, the unaudited interim consolidated financial statements 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 August 12, 2011.

The following information is based on the interim consolidated financial statements of the Company at June 30, 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. 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 for each of the periods ended March 31, 2011 and June 30, 2011 contain detailed descriptions of the Company's adoption of IFRS, including reconciliations 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 and 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, operating expenses and transportation 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 June 30, 2011, funds from operations were \$13.9 million, up 56% from the second quarter of 2010 and 28% from the first quarter of 2011 due to the Company's refocus on Cardium light oil drilling. Sales volumes for the three months ended June 30, 2011 averaged 7,758 BOED, which was consistent with the first quarter of 2011, but lower than expected. Significant wet weather conditions impacted production on-stream time, drilling and completion activities and facility construction. Management estimates that wet weather in the second quarter of 2011 reduced production by approximately 200 BOED.

Capital additions, net of proceeds from dispositions were \$26.3 million for the three months ended June 30, 2011. During the second quarter of 2011, the Company drilled four gross (2.8 net) Cardium light oil wells with a 100% success rate. The Company tied in nine gross (6.4 net) Cardium light oil wells in the second quarter of 2011.

Bank loans plus cash working capital deficiency were \$71.5 million at June 30, 2011, \$31.5 million lower than at March 31, 2011. On June 8, 2011, the Company completed a convertible subordinated debenture financing for proceeds, net of commission and expenses, of \$43.9 million. Proceeds were initially used to pay down bank debt. The availability created in the credit facilities, along with cash flows, will be used to help finance the Company's 2011 capital program.

*Revenue and Production.* In 2010, the Company changed its focus to oil prospects in light of the continued depressed natural gas market. Oil and natural gas liquids revenue represents 65% of total revenue in the second quarter of 2011, up 8% from the first quarter of 2011 and up 32% from the second quarter of 2010.

Gas sales volumes for the three months ended June 30, 2011 decreased to 32.0 MMcfd from 33.9 MMcfd in the first quarter of 2011. The decrease is a result of the Company's focus on oil prospects in conjunction with low 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 June 30, 2011 averaged 1,759 bpd compared to 1,372 bpd in the first quarter of 2011 and 491 bpd in the second quarter of 2010. The increase in volumes from the first quarter of 2011 is due to the nine gross (6.4 net) Cardium light oil wells tied in during the quarter.

Natural gas liquids sales for the three months ended June 30, 2011 averaged 667 bpd compared to 699 bpd in the first quarter of 2011 and 741 bpd for the second quarter of 2010. Natural gas liquids volumes were affected by natural declines, consistent with declines in gas production.

The following tables outline production revenue, volumes and average sales prices for the period ended June 30, 2011 and 2010.

## OIL AND NATURAL GAS REVENUE

(thousands of dollars)	Three months ended June 30		Six months ended June 30	
	2011	2010	2011	2010
Natural gas	\$ 11,034	\$ 13,421	\$ 21,954	\$ 28,680
Gain on fixed price natural gas contracts	-	-	-	1,302
Oil <sup>(1)</sup>	15,912	3,148	26,375	5,494
NGL	4,505	3,612	8,654	7,615
Royalty and other	115	137	169	492
<b>Total revenue<sup>(1)</sup></b>	<b>\$ 31,566</b>	<b>\$ 20,318</b>	<b>\$ 57,152</b>	<b>\$ 43,583</b>

(1) The three month numbers exclude the realized loss and unrealized gain on derivative contracts of \$0.8 million and \$7.7 million respectively during the three months ended June 30, 2011 (June 30, 2010 - \$Nil). The six month numbers exclude the realized loss and unrealized gain on derivative contracts of \$1.2 million and \$4.8 million respectively during the six months ended June 30, 2011 (June 30, 2010 - \$Nil).

## PRODUCTION

	Three months ended June 30		Six months ended June 30	
	2011	2010	2011	2010
Natural gas (Mcf)	31,990	38,998	32,955	37,120
Oil (bpd)	1,759	491	1,567	419
NGL (bpd)	667	741	683	763
<b>Total (BOED)</b>	<b>7,758</b>	<b>7,732</b>	<b>7,742</b>	<b>7,368</b>

## PRICES

	Three months ended June 30		Six months ended June 30	
	2011	2010	2011	2010
Natural gas (\$/Mcf) <sup>(1)</sup>	\$ 3.79	3.78	\$ 3.68	\$ 4.46
Oil (\$/bbl) <sup>(2)</sup>	99.39	70.45	93.00	72.51
NGL (\$/bbl)	74.24	53.55	70.03	55.15
<b>Total (\$/BOE)<sup>(2)(3)</sup></b>	<b>\$ 44.71</b>	<b>28.88</b>	<b>\$ 40.78</b>	<b>\$ 32.68</b>

(1) Six month price includes gain on fixed price natural gas contracts from the first quarter of 2010.

(2) The three month numbers exclude the realized loss and unrealized gain on derivative contracts of \$0.8 million and \$7.7 million respectively during the three months ended June 30, 2011 (June 30, 2010 - \$Nil). The six month numbers exclude the realized loss and unrealized gain on derivative contracts of \$1.2 million and \$4.8 million respectively during the six months ended June 30, 2011 (June 30, 2010 - \$Nil).

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

Anderson Energy's average natural gas sales price was \$3.79 per Mcf for the three months ended June 30, 2011, 6% higher than the first quarter of 2011 price of \$3.58 per Mcf and flat compared to the second quarter of 2010 price of \$3.78 per Mcf. Anderson Energy's average gas sales price was \$3.68 per Mcf for the six months ended June 30, 2011, 17% lower than the first half of 2010 price of \$4.46 per Mcf. The natural gas price in the first quarter of 2010 includes a gain of \$1.3 million on the Company's fixed price natural gas contracts. The gas price before the gain was \$4.27 per Mcf in the first half of 2010. Gas prices have been significantly affected by increased supply and lower industrial consumption of natural gas in the United States.

Historically, Anderson Energy has sold most of its gas at Alberta spot market prices. The Company is currently selling all of its unhedged gas production at the average daily index price. The Company has classified transportation costs as an offset to gas sales revenue as title transfers prior to transport on the applicable sales pipelines and transportation is being held by and charged by the gas purchasers. The Company has arranged firm service transportation

agreements covering approximately 24 MMcfd of natural gas sales for various terms expiring in one to nine years.

**Commodity Contracts.** At June 30, 2011 the following derivative contracts summarized on a quarterly basis were outstanding and recorded at estimated fair value:

<i>Period</i>	<i>Weighted average volume (bbls)</i>	<i>Weighted average WTI Canadian (\$/bbl)</i>
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

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

<i>(thousands of dollars)</i>	<i>Three months ended June 30,</i>		<i>Six months ended June 30,</i>	
	<i>2011</i>	<i>2010</i>	<i>2011</i>	<i>2010</i>
Realized loss on derivative contracts	\$ (824)	\$ -	\$ (1,224)	\$ -
Unrealized gain on derivative contracts	7,665	-	4,816	-
	<u>\$ 6,841</u>	<u>\$ -</u>	<u>\$ 3,592</u>	<u>\$ -</u>

In June 2011, as part of its risk management program, the Company entered into fixed price natural gas contracts to manage commodity price risk. The Company entered into physical contracts to sell 15,000 GJ per day of natural gas from July 1, 2011 to October 31, 2011 at an average AECO price of \$4.06 per GJ. The Company does not mark-to-market physical sales contracts as they are not considered to be derivative instruments. These contracts will affect the price of the commodity sold during the period of the contract.

**Royalties.** Royalties were 12.0% of revenue for the three months ended June 30, 2011 compared to 9.0% for the first quarter of 2010 and 8.3% for the three months ended June 30, 2010. The royalty rate increased in the second quarter of 2011 as a result of annual gas cost allowance ("GCA") adjustments related to the prior year. As a result of low natural gas prices and declining natural gas production, GCA previous paid was clawed back on the annual adjustment. In contrast, a large positive adjustment was received in 2010.

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 June 30</i>		<i>Six months ended June 30</i>	
	<i>2011</i>	<i>2010</i>	<i>2011</i>	<i>2010</i>
Gross Crown royalties (%)	8.8%	12.0%	9.3%	13.5%
Gas cost allowance (%)	(3.8%)	(10.1%)	(5.2%)	(8.3%)
Other royalties (%)	7.0%	6.4%	6.6%	6.5%
Royalties (%)	<u>12.0%</u>	<u>8.3%</u>	<u>10.7%</u>	<u>11.7%</u>
Royalties (\$/BOE)	\$ 5.37	\$ 2.41	\$ 4.35	\$ 3.82

**Operating Expenses.** Operating expenses were \$12.04 per BOE for the three months ended June 30, 2011 compared to \$10.63 per BOE in the first quarter of 2011 and \$9.71 per BOE in the second quarter of 2010. Operating expenses were \$11.34 per BOE for the six months ended June 30, 2011 compared to \$10.21 per BOE in the first half of 2010. The increase is due to costs associated with temporary production facilities being utilized for longer periods of time in 2011 as a result of an extended spring breakup and extremely wet weather. These costs negatively impacted operating expenses in the second quarter of 2011 by \$0.78 per BOE. These facilities are now permanently connected to the new Garrington battery consolidation project and to a permanent battery installation in Willesden Green. In addition, the Company received large invoices for amended gas processing fees at Bigoray, and for 2008 and 2009 equalizations in West Pembina.

**Transportation Expenses.** Transportation expenses were \$0.66 per BOE for the three months ended June 30, 2011 compared to \$0.33 per BOE in the first quarter of 2011 and \$0.18 per BOE in the second quarter of 2010. Transportation expenses were \$0.50 per BOE for the six months ended June 30, 2011 compared to \$0.16 per BOE in the first half of 2010. The increase in transportation expenses in 2011 is the result of more clean oil trucking charges. In the first half of 2010, oil production was 5.7% of total production compared with 20.2% in the first half of 2011. Previously, the Company included transportation expenses with operating expenses as they were not significant to disclose separately.

#### OPERATING NETBACK

<i>(thousands of dollars)</i>	<i>Three months ended June 30</i>		<i>Six months ended June 30</i>	
	<i>2011</i>	<i>2010</i>	<i>2011</i>	<i>2010</i>
Revenue <sup>(1)</sup>	\$ 31,566	\$ 20,318	\$ 57,152	\$ 43,583
Realized loss on derivative contracts	(824)	-	(1,224)	-
Royalties	(3,790)	(1,696)	(6,093)	(5,090)
Operating expenses	(8,493)	(6,830)	(15,883)	(13,619)
Transportation expenses	(469)	(128)	(702)	(215)
	<u>\$ 17,990</u>	<u>\$ 11,664</u>	<u>\$ 33,250</u>	<u>\$ 24,659</u>
Sales (MBOE)	706.0	703.6	1,401.3	1,333.6
Per BOE				
Revenue <sup>(1)</sup>	\$ 44.71	\$ 28.88	\$ 40.78	\$ 32.68
Realized loss on derivative contracts	(1.17)	-	(0.87)	-
Royalties	(5.37)	(2.41)	(4.35)	(3.82)
Operating expenses	(12.04)	(9.71)	(11.34)	(10.21)
Transportation expenses	(0.66)	(0.18)	(0.50)	(0.16)
	<u>\$ 25.47</u>	<u>\$ 16.58</u>	<u>\$ 23.72</u>	<u>\$ 18.49</u>

(1) Includes royalty and other income classified with oil and gas sales. For the three months ended June 30, 2011, excludes unrealized gain on derivative contracts of \$7.7 million pertaining to fixed price crude oil swaps. For the six months ended June 30, 2011 excludes an unrealized gain of \$4.8 million pertaining to fixed price crude oil swaps.

**General and Administrative Expenses.** General and administrative expenses excluding stock-based compensation were \$2.0 million or \$2.86 per BOE for the three months ended June 30, 2011 compared to \$2.6 million or \$3.80 per BOE in the first quarter of 2011 and \$2.0 million or \$2.88 per BOE for the three months ended June 30, 2010. General and administrative expenses were \$4.7 million or \$3.32 per BOE for the six months ended June 30, 2011 compared to \$3.9 million or \$2.96 per BOE for the first half of 2010. General and administrative expenses decreased overall in the second quarter of 2011, as compared to the first quarter of 2011 as the first quarter of 2011 contained annual bonus payments. Under IFRS, general and administrative expenses are shown inclusive of share-based payments on the consolidated statement of operations and comprehensive income (loss). IFRS also requires that the capitalization of general and administrative costs be limited to directly attributable costs. Capitalized general and administrative costs are limited to salaries and associated office rent of staff involved in capital activities. 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 \$0.1 million for the three months ended June 30, 2011 and by \$0.3 for the six month ended June 30, 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 June 30,</i>		<i>Six months ended June 30,</i>	
	<i>2011</i>	<i>2010</i> <i>(restated)</i>	<i>2011</i>	<i>2010</i> <i>(restated)</i>
General and administrative (gross)	\$ 3,566	\$ 3,286	\$ 7,693	\$ 6,312
Overhead recoveries	(457)	(322)	(810)	(769)
Capitalized	<u>(1,092)</u>	<u>(936)</u>	<u>(2,224)</u>	<u>(1,596)</u>
General and administrative (cash)	\$ 2,017	\$ 2,028	\$ 4,659	\$ 3,947
Net stock-based compensation	<u>257</u>	<u>211</u>	<u>491</u>	<u>404</u>
General and administrative (net)	\$ 2,274	\$ 2,239	\$ 5,150	\$ 4,351
General and administrative (cash) <i>(\$/BOE)</i>	\$ 2.86	\$ 2.88	\$ 3.32	\$ 2.96
% Capitalized	31%	28%	29%	25%

**Stock-Based Compensation.** The Company accounts for stock-based compensation plans using the fair value method of accounting. Stock-based compensation expense was \$0.4 million for the second quarter of 2011 (\$0.3 million net of amounts capitalized) versus \$0.4 million (\$0.2 million net of amounts capitalized) in the second quarter of 2010. Stock-based compensation expense was \$0.8 million for the first half of 2011 (\$0.5 million net of amounts capitalized) versus \$0.7 million (\$0.4 million net of amounts capitalized) in the comparable period of 2010. The increase is a result of additional stock options granted to new and existing employees.

**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 \$2.8 million for the second quarter of 2011, compared to \$2.4 million in the first quarter of 2011 and \$1.1 million in the second quarter of 2010. Finance expenses were \$5.2 million for the six months ended June 30, 2011, compared to \$2.2 million in comparable period of 2010. The increase in finance expenses is the result of higher interest and accretion on the convertible debentures issued on December 31, 2010 and June 8, 2011, and higher interest rates, partially offset by lower average bank loans. Bank loans, were \$45.6 million at June 30, 2011 compared to \$59.2 million at March 31, 2011 and \$55.6

million at June 30, 2010. The average effective interest rate on outstanding bank loans was 5.7% for the six months ended June 30, 2011 compared to 5.0% for the comparable period in 2010.

<i>(thousands of dollars)</i>	<i>Three months ended June 30,</i>		<i>Six months ended June 30,</i>	
	<i>2011</i>	<i>2010</i>	<i>2011</i>	<i>2010</i>
		<i>(restated)</i>		<i>(restated)</i>
Interest and accretion on convertible debentures	\$ 1,441	\$ -	\$ 2,598	\$ -
Interest expense on credit facilities and other	889	719	1,724	1,418
Accretion on decommissioning obligations	439	411	856	814
Finance expenses	<u>\$ 2,769</u>	<u>\$ 1,130</u>	<u>\$ 5,178</u>	<u>\$ 2,232</u>

**Depletion and Depreciation.** Depletion and depreciation was \$13.3 million (\$18.90 per BOE) for the second quarter of 2011 compared to \$12.4 million (\$17.77 per BOE) in the first quarter of 2011 and \$11.5 million (\$16.30 per BOE) in the second quarter of 2010. Depletion and depreciation was \$25.7 million (\$18.34 per BOE) for the first half of 2011 compared \$21.8 million (\$16.36 per BOE) for the comparable period in 2010. The increase in depletion and depreciation in the second quarter of 2011 is the result of higher depletion rates on upfront Cardium oil capital costs.

**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 six months ended June 30, 2010 and the year ended December 31, 2010 the Company recognized additional impairments of \$62.7 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 June 30, 2011, therefore the Company did not test for impairment. In addition, there were no indicators of impairment reversal in the second 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 July 1, 2011 were as follows:

	<i>AECO Gas Price (\$Cdn/Mcf)</i>	<i>WTI Cushing (\$US/bbl)</i>	<i>Exchange rate (US\$/Cdn)</i>
2011 Q3-Q4	4.08	97.50	1.00
2012	4.59	100.00	0.98
2013	5.05	100.00	0.98
2014	5.51	100.00	0.98
2015	5.97	100.00	0.98
2016	6.43	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 a \$0.1 million increase in decommissioning obligations in the second quarter of 2011 related to current activity and changes in estimates. Accretion expense was \$0.4 million for the second quarter of 2011 compared to \$0.4 million in the second quarter of 2010 and was included in finance expenses.

**Income Taxes.** Anderson Energy is not currently taxable. The Company does not anticipate paying current income tax in 2011. The Company has approximately \$436 million in tax pools at June 30, 2011.

**Funds from Operations.** Funds from operations for the second quarter of 2011 were \$13.9 million (\$0.08 per share), a 28% increase over the \$10.9 million (\$0.06 per share) recorded in the first quarter of 2011 and 56% higher than the \$8.9 million (\$0.05 per share) recorded in the same period of the prior year. Funds from operations for the first half of 2011 were \$24.8 million (\$0.14 per share) compared to \$19.3 million (\$0.12 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 funds from operations per BOE when compared to natural gas properties. As new crude oil production is brought on-stream at higher expected operating margins, funds from operations are expected to increase. The changes in funds from operations as reported under IFRS for the three and six month ended June 30, 2010 relate to the decrease in the capitalized general and administrative costs of \$0.1 million and \$0.3 million respectively from what was previously reported under CGAAP.

	<i>Three months ended June 30</i>		<i>Six months ended June 30</i>	
	<i>2011</i>	<i>2010 (restated)</i>	<i>2011</i>	<i>2010 (restated)</i>
<i>(thousands of dollars)</i>				
Cash from operating activities	\$ 14,953	\$ 8,811	\$ 25,954	\$ 21,557
Changes in non-cash working capital	(1,025)	(678)	(1,184)	(3,218)
Decommissioning expenditures	16	790	42	1,019
Funds from operations	\$ 13,944	\$ 8,923	\$ 24,812	\$ 19,358

**Earnings (loss).** The Company reported earnings of \$5.9 million in the second quarter of 2011 compared to a loss of \$3.7 million for the three months ended March 31, 2011 and a loss of \$4.8 million for the second quarter of 2010. The Company reported earnings of \$2.3 million in the first half of 2011 compared to a loss of \$49.2 million in the first half of 2010. Earnings in the second quarter of 2011 are a result of the unrealized gain on derivative contracts along with increased oil production combined with higher oil and NGL prices. The 2010 loss was due to a \$62.7 million impairment recorded in the period.

The Company's funds from operations and earnings are highly sensitive to changes in factors that are beyond its control, such as commodity prices and weather. 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 \$26.3 million on capital additions, net of proceeds on dispositions in the second quarter of 2011. The breakdown of expenditures is shown below:

<i>(thousands of dollars)</i>	<i>Three months ended June 30</i>		<i>Six months ended June 30</i>	
	<i>2011</i>	<i>2010 (restated)</i>	<i>2011</i>	<i>2010 (restated)</i>
Land, geological and geophysical costs	\$ 3,479	569	\$ 3,766	\$ 597
Acquisitions	-	9	-	733
Proceeds on disposition	(167)	(38)	(5,367)	(2,207)
Drilling, completion and recompletion	12,662	5,945	51,560	22,989
Drilling incentive credits	(291)	-	(138)	(2,614)
Facilities and well equipment	9,483	5,128	16,565	25,872
Capitalized G&A	1,092	936	2,224	1,596
Total finding, development & acquisition Expenditures	26,258	12,549	68,610	46,966
Change in compressor and other equipment inventory	-	75	-	(1,124)
Office equipment and furniture	26	40	28	49
Total net cash capital expenditures	\$ 26,284	12,664	\$ 68,638	\$ 45,891

Drilling statistics are shown below:

	<i>Three months ended June 30</i>				<i>Six months ended June 30</i>			
	<i>2011</i>		<i>2010</i>		<i>2011</i>		<i>2010</i>	
	<i>Gross</i>	<i>Net</i>	<i>Gross</i>	<i>Net</i>	<i>Gross</i>	<i>Net</i>	<i>Gross</i>	<i>Net</i>
Gas	-	-	1	0.6	-	-	20	16.6
Oil	5	2.9	2	0.9	20	16.2	5	3.2
Dry	-	-	-	-	-	-	4	2.8
<b>Total</b>	<b>5</b>	<b>2.9</b>	<b>3</b>	<b>1.5</b>	<b>20</b>	<b>16.2</b>	<b>29</b>	<b>22.6</b>
<b>Success rate (%)</b>	<b>100%</b>	<b>100%</b>	<b>100%</b>	<b>100%</b>	<b>100%</b>	<b>100%</b>	<b>86%</b>	<b>88%</b>

During the second quarter of 2011, the Company drilled four gross (2.8 net capital) Cardium horizontal light oil wells. In addition, the Company brought nine gross (6.4 net revenue) Cardium horizontal light wells on-stream. Approximately \$9.5 million was spent on facilities and well equipment during the second quarter of 2011.

Drilling incentive credits earned are capped at 50% of crown royalties paid between April 1, 2009 and March 31, 2011 and the Company earned more drilling credits that it was 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. The Company has not received its final calculation of these credits, pending final adjustments to royalties paid during this period. As a result of the cap, in the second quarter of 2011, the Company reduced its estimate of drilling incentive credits that it will be entitled to by a further \$0.2 million, to a total of \$4.3 million. The Company received \$0.5 million in proceeds from the sale of surplus credits during the second 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 August 12, 2011, there were 172.5 million common shares outstanding, 11.4 million stock options outstanding, \$50.0 million principal amount of convertible debentures which are convertible into common shares at a conversion price of \$1.55 per common share and \$46.0 million principal amount of convertible debentures which are convertible into common shares at a conversion price of \$1.70 per common share. During the second quarter of 2011, 4,400 common shares (2010 – Nil) were issued under the employee stock option plan.

	<i>Three months ended June 30</i>		<i>Six months ended June 30</i>	
	<i>2011</i>	<i>2010</i>	<i>2011</i>	<i>2010</i>
High	\$ 1.23	\$ 1.32	\$ 1.36	\$ 1.57
Low	\$ 0.77	\$ 1.02	\$ 0.77	\$ 1.02
Close	\$ 0.80	\$ 1.18	\$ 0.80	\$ 1.18
Volume	23,392,247	26,669,464	84,968,086	70,312,536
Shares outstanding at June 30	172,549,701	172,400,401	172,549,701	172,400,401
<b>Market capitalization at June 30</b>	<b>\$ 138,039,761</b>	<b>\$ 203,432,473</b>	<b>\$ 138,039,761</b>	<b>\$ 203,432,473</b>

The statistics above include trading on the Toronto Stock Exchange only. Shares also trade on alternative platforms like Alpha, Chi-X, Pure and Omega. During the three and six months ended

June 30, 2011 approximately 22.1 million and 65.7 million common shares traded on these alternative exchanges respectively.

### ELIMINATION OF DEFICIT

On May 16, 2011 the Company's shareholders approved an ordinary resolution to eliminate the Company's accumulated deficit at January 1, 2011 against share capital without reduction to stated capital or paid up capital. The Company's accumulated deficit at January 1, 2011 was largely the result of the implementation of IFRS combined with the significant reduction in natural gas prices in recent years which reduced profitability and resulted in write downs of historical costs. The Company believes that the elimination of the consolidated accounting deficit, in connection with the implementation of IFRS, is beneficial on a go-forward basis. The accounting adjustment should allow shareholders to better evaluate reporting under IFRS as well as measure the success of the Company's response to detrimental changes in the natural gas business by transitioning to a more oil weighted company.

### LIQUIDITY AND CAPITAL RESOURCES

At June 30, 2011, the Company had outstanding long-term bank loans of \$45.6 million, convertible debentures of \$96.0 million (principal) and a working capital deficiency of \$25.9 million, excluding the unrealized gain on derivative contracts. The working capital deficiency is due to accruals associated with the capital program. The following table shows the changes in bank loans plus cash working capital deficiency:

<i>(thousands of dollars)</i>	<i>Three months ended June 30</i>		<i>Six months ended June 30</i>	
	<i>2011</i>	<i>2010</i>	<i>2011</i>	<i>2010</i>
		<i>(restated)</i>		<i>(restated)</i>
Bank loans plus cash working capital deficiency, beginning of period	\$ (102,971)	\$ (65,753)	\$ (71,507)	\$ (72,524)
Funds from operations	13,944	8,923	24,812	19,358
Net cash capital expenditures	(26,284)	(12,664)	(68,638)	(45,891)
Proceeds from issue of convertible debentures, net of issue costs	43,860	-	43,860	-
Proceeds from issue of share capital, net of issue costs	-	-	-	29,792
Proceeds from exercise of stock options	3	-	51	-
Decommissioning expenditures	(16)	(790)	(42)	(1,019)
Bank loans plus cash working capital deficiency, end of period	<u>\$ (71,464)</u>	<u>\$ (70,284)</u>	<u>\$ (71,464)</u>	<u>\$ (70,284)</u>

The Company's 2011 net capital budget is \$115 million, of which \$68.6 million was spent in the first half of 2011. 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 28 gross (23.9 net capital, 20.8 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 June 30, 2011, the Company had total credit facilities of \$135 million and \$89.3 million of credit available under these facilities. On June 8, 2011, the Company completed a convertible

subordinated debenture financing for proceeds, net of commission and expenses, of \$43.9 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 11, 2012, 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 11, 2012. The supplemental facility is available on a revolving basis and expires on July 11, 2012 with any amounts outstanding due in full at that time. No amounts were drawn under the supplemental facility at June 30, 2011.
- *Convertible debentures* – The Company has \$96.0 million (principal) in convertible debentures outstanding at June 30, 2011, of which \$50.0 million bears interest at 7.5% (“Series A Convertible Debentures”) and \$46.0 million bears interest at 7.25% (“Series B Convertible Debentures”). The convertible debentures have a face value of \$1,000 with interest payable semi-annually. The Series A Convertible Debentures mature on January 31, 2016 with interest payable on the last day of July and January commencing July 31, 2011. These 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 and are not redeemable by the Company before January 31, 2014. The Series B Convertible Debentures mature on June 30, 2017 with interest payable on the last day of June and December, commencing December 31, 2011. These convertible debentures and are convertible at the holder's option at a conversion price of \$1.70 per common share, subject to adjustment in certain events and are not redeemable by the Company before June 30, 2014.
- *Lease for office space* – This lease expires on November 30, 2012. Future minimum lease payments are expected to be \$0.9 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 24 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 \$0.8 million for the remainder of 2011, \$1.4 million in 2012, \$0.8 million in 2013, \$0.7 million in 2014, \$0.6 million in 2015 and \$0.4 million thereafter.
- *Oil transportation contract* – In 2010, the Company entered into a facilities construction and operation agreement pursuant to which it is committed to ship a minimum volume of gross crude oil through new facilities and pipelines being constructed in Garrington. The total financial commitment is \$2.6 million to be incurred over a minimum of five years. The contract contains a minimum volume requirement per year for the first five years following completion of construction which is expected to be late 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 June 30, 2011. 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 15 to the interim consolidated financial statements for the three and six months ended June 30, 2011 and 2010.

#### INTERNATIONAL FINANCIAL REPORTING STANDARDS

The Company adopted IFRS effective January 1, 2011. As a result, the Company's financial results for the six months ended June 30, 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 each of the periods ended March 31, 2011 and June 30, 2011 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.

On August 4, 2011, the IASB issued an exposure draft proposing to change the mandatory effective date of IFRS 9 to annual periods beginning on or after January 1, 2015 from the original effective date of January 1, 2013. Early adoption is permitted and the standard is required to be applied retrospectively. The comment period for this exposure draft closes on October 21, 2011.

The implementation of the issued standard is not expected to have a significant impact on the Company's financial position or results.

*Reporting Entity.* In May 2011, the IASB issued IFRS 10 Consolidated Financial Statement, IFRS 11 Joint Arrangements, IFRS 12 Disclosures of Interests in Other Entities, and amendments to IAS 27 Separate Financial Statements and IAS 28 Investments in Associates and Joint Ventures.

IFRS 10 creates a single consolidation model by revising the definition of control in order to apply the same control criteria to all types of entities, including joint arrangements, associates and special purpose vehicles. IFRS 11 establishes a principle-based approach to the accounting for joint arrangements by focusing on the rights and obligations of the arrangement and limits the application of proportionate consolidation accounting to arrangements that meet the definition of a joint operation. IFRS 12 is a comprehensive disclosure standard for all forms of interests in other entities, including joint arrangements, associates and special purpose vehicles.

Retrospective application of these standards with relief for certain transactions is effective for fiscal years beginning on or after January 1, 2013, with earlier application permitted if all five standards are collectively adopted.

*IFRS 13 – Fair Value Measurement.* In May 2011, the IASB issued IFRS 13 Fair Value Measurement, which establishes a single source of guidance for all fair value measurements; clarifies the definition of fair value; and enhances the disclosures on fair value measurement. Prospective application of this standard is effective for fiscal years beginning on or after January 1, 2013, with early application permitted.

*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.

## 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 had increased earlier this year, and continue to remain volatile as they are a geopolitical commodity, responding to concerns about economic markets in the US and Europe and continued 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 believes it 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 124.5 gross (73.7 net) sections in the Cardium fairway and has identified an inventory of 213 gross (128.6 net) drill ready Cardium horizontal oil locations, of which 50 gross (36.2 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 goal is to grow its oil production to achieve 50% of total production from oil and NGL by sometime in 2012. The capital budget for 2011 is \$115 million and annual production guidance for 2011 is between 7,500 and 8,000 BOED. The Company could have considered a budget which yielded higher BOED production growth through spending on natural gas prospects, but elected to proceed with a 100% oil capital budget which does not create BOED production growth in 2011, but which yields substantially higher cash flows through stronger netbacks. We are now starting to see these higher netbacks. We expect a return to BOED production growth in 2012 in addition to higher cash flows.

Risks associated with the production guidance provided 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>Q2 2011</b>	<b>Q1 2011</b>	<b>Q4 2010</b> <i>(restated)</i>	<b>Q3 2010</b> <i>(restated)</i>
Revenue, net of royalties	\$ 27,776	\$ 23,283	\$ 21,690	\$ 17,263
Funds from operations	\$ 13,944	\$ 10,868	\$ 9,282	\$ 7,876
Funds from operations per share, basic and diluted	\$ 0.08	\$ 0.06	\$ 0.05	\$ 0.05
Earnings (loss) before effect of impairment	\$ 5,932	\$ (3,681)	\$ (4,864)	\$ (3,057)
Earnings (loss) per share before effect of impairment				
Basic and diluted	\$ 0.03	\$ (0.02)	\$ (0.03)	\$ (0.02)
Earnings (loss)	\$ 5,932	\$ (3,681)	\$ (36,545)	\$ (39,029)
Basic and diluted	\$ 0.03	\$ (0.02)	\$ (0.21)	\$ (0.23)
Capital expenditures, including acquisitions net of dispositions	\$ 26,284	\$ 42,354	\$ 26,240	\$ 39,378
Cash from operating activities	\$ 14,953	\$ 11,001	\$ 10,489	\$ 8,287
Daily sales				
Natural gas ( <i>Mcf</i> )	31,990	33,931	38,479	35,778
Liquids ( <i>bpd</i> )	2,426	2,071	1,815	1,329
BOE ( <i>BOED</i> )	7,758	7,726	8,228	7,292
Average prices				
Natural gas ( <i>\$/Mcf</i> )	\$ 3.79	\$ 3.58	\$ 3.48	\$ 3.43
Liquids ( <i>\$/bbl</i> )	\$ 92.48	\$ 78.39	\$ 69.11	\$ 58.61
BOE ( <i>\$/BOE</i> )*	\$ 44.71	\$ 36.80	\$ 31.63	\$ 28.21

	<b>IFRS</b>		<b>CGAAP</b>	
	<b>Q2 2010</b> <i>(restated)</i>	<b>Q1 2010</b> <i>(restated)</i>	<b>Q4 2009</b>	<b>Q3 2009</b>
Revenue, net of royalties	\$ 18,622	\$ 19,871	\$ 18,708	\$ 13,813
Funds from operations	\$ 8,923	\$ 10,435	\$ 9,151	\$ 6,623
Funds from operations per share, basic and diluted	\$ 0.05	\$ 0.06	\$ 0.06	\$ 0.04
Earnings (loss) before effect of impairment	\$ (2,450)	\$ 256	\$ (6,457)	\$ (9,432)
Earnings (loss) per share before effect of impairment				
Basic and diluted	\$ (0.01)	\$ -	\$ (0.04)	\$ (0.06)
Loss	\$ (4,769)	\$ (44,444)	\$ (6,457)	\$ (9,432)
Loss per share, basic and diluted	\$ (0.03)	\$ (0.27)	\$ (0.04)	\$ (0.06)
Capital expenditures, including acquisitions net of dispositions	\$ 12,664	\$ 33,227	\$ 11,312	\$ 6,571
Cash from operating activities	\$ 8,811	\$ 12,746	\$ 5,361	\$ 6,689
Daily sales				
Natural gas ( <i>Mcf</i> )	38,998	35,221	34,938	36,282
Liquids ( <i>bpd</i> )	1,232	1,130	1,257	1,013
BOE ( <i>BOED</i> )	7,732	7,000	7,080	7,060
Average prices				
Natural gas ( <i>\$/Mcf</i> )	\$ 3.78	\$ 5.22	\$ 4.28	\$ 2.81
Liquids ( <i>\$/bbl</i> )	\$ 60.28	\$ 62.43	\$ 53.79	\$ 53.84
BOE ( <i>\$/BOE</i> )*	\$ 28.88	\$ 36.93	\$ 31.38	\$ 22.50

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

## FORWARD-LOOKING STATEMENTS

*Certain statements 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; percentage of production from oil and natural gas liquids; dates of commencement of production; amount of capital expenditures and the timing and method of financing 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 in the royalty regime applicable to the Company; estimates of future revenues, costs, netbacks, funds from operations and debt levels; 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; adequate weather to conduct operations; sufficiency of budgeted capital, operating and other costs to carry out planned activities; 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; ability to access sufficient capital from internal and external sources; and other factors, many of which are beyond the Company's control. The impact of any one risk, uncertainty or factor on a particular forward-looking statement is not determinable with certainty as the factors are interdependent, and management's future course of action would depend on its assessment of all information at the time. As a consequence, actual results may differ materially from those anticipated in the forward-looking statements and readers should not place undue reliance on the assumptions and 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)) or at Anderson Energy's website ([www.andersonenergy.ca](http://www.andersonenergy.ca)).*

*Estimates of future revenues, costs, netbacks, funds from operations and debt levels may constitute future oriented financial information or a financial outlook under applicable securities laws, and are presented to provide readers with a comparison to levels in 2009 and 2010 based on the various assumptions described or inherent in the estimates. Readers are cautioned that the information may not be appropriate for other purposes.*

*This news release contains information regarding forecasts that were obtained from reports prepared by third parties. None of the authors of such reports have provided any form of consultation, advice or counsel regarding any aspect of this news release. Actual outcomes may vary materially from the forecast in such reports, and the prospect for material variation can be expected to increase as the length of the forecast period increases.*

*The forward-looking statements contained in this news release are made as at the date of this news release and the Company 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.*

## CONVERSION

*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)

	June 30, 2011	December 31, 2010
<b>ASSETS</b>		
Current assets:		
Cash and cash equivalents	\$ -	\$ 4,024
Accounts receivables and accruals (note 13)	18,303	20,998
Prepaid expenses and deposits	2,847	3,052
Current portion of unrealized gain on derivative contracts (note 13)	1,732	-
	<u>22,882</u>	<u>28,074</u>
Deferred taxes	27,155	29,657
Unrealized gain on derivative contracts (note 13)	1,166	-
Property, plant and equipment (note 4 and 5)	365,952	320,673
	<u>\$ 417,155</u>	<u>\$ 378,404</u>
<b>LIABILITIES AND SHAREHOLDERS' EQUITY</b>		
Current liabilities:		
Accounts payable and accruals	\$ 47,008	\$ 46,862
Unrealized loss on derivative contracts (note 13)	-	1,918
	<u>47,008</u>	<u>48,780</u>
Bank loans (note 6)	45,606	52,719
Convertible debentures (note 7)	83,872	43,460
Decommissioning obligations (note 8)	53,268	51,550
	<u>229,754</u>	<u>196,509</u>
Shareholders' equity:		
Share capital (note 9)	171,460	426,925
Equity component of convertible debentures (note 7)	5,019	2,592
Contributed surplus	8,671	7,921
Retained earnings (deficit) (note 9)	2,251	(255,543)
	<u>187,401</u>	<u>181,895</u>
Commitments (note 15)		
Subsequent event (note 16)		
	<u>\$ 417,155</u>	<u>\$ 378,404</u>

See accompanying notes to the consolidated financial statements.

# ANDERSON ENERGY LTD.

## Consolidated Statements of Operations and Comprehensive Income (Loss)

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

	Three months ended June 30,		Six months ended June 30,	
	2011	2010 (note 17)	2011	2010 (note 17)
Oil and gas sales	\$ 31,566	\$ 20,318	\$ 57,152	\$ 43,583
Royalties	<u>(3,790)</u>	<u>(1,696)</u>	<u>(6,093)</u>	<u>(5,090)</u>
Revenue, net of royalties	27,776	18,622	51,059	38,493
Realized loss on derivative contracts	(824)	-	(1,224)	-
Unrealized gain on derivative contracts	7,665	-	4,816	-
Gain on sale of property, plant and equipment	<u>761</u>	<u>35</u>	<u>1,146</u>	<u>708</u>
	35,378	18,657	55,797	39,201
Operating expenses	8,493	6,830	15,883	13,619
Transportation expenses	469	128	702	215
Depletion and depreciation	13,341	11,468	25,696	21,812
Impairment of property, plant and equipment (note 5)	-	3,112	-	62,652
General and administrative expenses	<u>2,274</u>	<u>2,239</u>	<u>5,150</u>	<u>4,351</u>
Earnings (loss) from operating activities	10,801	(5,120)	8,366	(63,448)
Finance income (note 11)	10	6	33	64
Finance expenses (note 11)	<u>(2,769)</u>	<u>(1,130)</u>	<u>(5,178)</u>	<u>(2,232)</u>
Net finance expenses	(2,759)	(1,124)	(5,145)	(2,168)
Earnings (loss) before taxes	8,042	(6,244)	3,221	(65,616)
Deferred income tax expense (benefit)	<u>2,110</u>	<u>(1,475)</u>	<u>970</u>	<u>(16,403)</u>
Earnings (loss) and comprehensive income (loss) for the period	5,932	(4,769)	2,251	(49,213)
Basic and diluted earnings (loss) per share (note 10)	\$ 0.03	\$ (0.03)	\$ 0.01	\$ (0.29)

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 Common Shares	Share capital	Equity component of convertible debentures	Contributed surplus	Retained earnings (deficit)	Total shareholders' equity
Balance at January 1, 2010	150,500,401 \$	396,524 \$	- \$	6,338 \$	(130,756) \$	272,106
Issued pursuant to prospectus (note 9)	21,900,000	31,755	-	-	-	31,755
Share issue costs, net of tax of \$0.5 million	-	(1,456)	-	-	-	(1,456)
Share-based payments	-	-	-	711	-	711
Loss for the period	-	-	-	-	(49,213)	(49,213)
Balance at June 30, 2010 (note 17)	172,400,401	426,823	-	7,049	(179,969)	253,903
Balance at January 1, 2011	172,485,301	426,925	2,592	7,921	(255,543)	181,895
Elimination of deficit (note 9)	-	(255,543)	-	-	255,543	-
Equity component of convertible debentures, net of tax of \$1.5 million (note 7)	-	-	2,427	-	-	2,427
Share-based payments	-	-	-	777	-	777
Options exercised	64,400	78	-	(27)	-	51
Earnings for the period	-	-	-	-	2,251	2,251
Balance at June 30, 2011	172,549,701 \$	171,460 \$	5,019 \$	8,671 \$	2,251 \$	187,401

See accompanying notes to the consolidated financial statements.

# ANDERSON ENERGY LTD.

## Consolidated Statements of Cash Flows

SIX MONTHS ENDED JUNE 30, 2011 AND 2010

(Stated in thousands of dollars)  
(Unaudited)

	2011	2010 (note 17)
<b>CASH PROVIDED BY (USED IN) OPERATIONS</b>		
Earnings (loss) for the period	\$ 2,251	\$ (49,213)
Adjustments for:		
Depletion and depreciation	25,696	21,812
Unrealized gain on derivative contracts	(4,816)	-
Impairment losses on property, plant and equipment	-	62,652
Deferred income tax expense (benefit)	970	(16,403)
Gain on sale of property, plant and equipment	(1,146)	(708)
Stock-based compensation	491	404
Accretion on decommissioning obligations	856	814
Accretion on convertible debentures	510	-
Decommissioning expenditures	(42)	(1,019)
Changes in non-cash working capital (note 12)	<u>1,184</u>	<u>3,218</u>
	25,954	21,557
<b>FINANCING</b>		
Decrease in bank loans	(7,113)	(6,796)
Proceeds from issue of convertible debentures, net of issue costs (note 7)	43,860	-
Proceeds from issue of share capital, net of issue costs	-	29,792
Proceeds from exercise of stock options	51	-
Changes in non-cash working capital (note 12)	<u>(34)</u>	<u>150</u>
	36,764	23,146
<b>INVESTING</b>		
Property, plant and equipment expenditures	(74,005)	(48,098)
Proceeds from sale of property, plant and equipment	5,367	2,207
Changes in non-cash working capital (note 12)	<u>1,896</u>	<u>1,190</u>
	<u>(66,742)</u>	<u>(44,701)</u>
Increase (decrease) in cash and cash equivalents	(4,024)	2
Cash and cash equivalents, beginning of period	<u>4,024</u>	<u>1</u>
Cash, end of period	\$ -	\$ 3
Interest received in cash	\$ 33	\$ 61
Interest paid in cash	\$ (990)	\$ (917)

See accompanying notes to the consolidated financial statements.

# ANDERSON ENERGY LTD.

## Notes to the Interim Consolidated Financial Statements

THREE AND SIX MONTHS ENDED JUNE 30, 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 using accounting policies consistent with International Financial Reporting Standards (“IFRS”) and in accordance with International Accounting Standard 34 *Interim Financial Reporting*.

The preparation of financial statements requires management to make judgements, estimates and assumptions that affect the application of policies and reported amounts of assets and liabilities, and revenue and expenses. The estimates and associated assumptions are based on historical experience and various other factors that are believed to be reasonable under the circumstances, the results of which form the basis of making the judgements about carrying values of asset and liabilities that are not readily apparent from other sources. Actual results may differ from these estimates.

The 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 periods affected.

Judgements made by management in the application of IFRS that have a significant effect on the financial statements and estimates with a significant risk of material adjustment in the current and following fiscal years are discussed in note 2(d) of the Company’s interim consolidated financial statements for the three months ended March 31, 2011.

These condensed interim consolidated financial statements do not include all of the information required for full annual financial statements. These interim consolidated financial statements have been prepared following the same accounting policies and methods of computation as the interim consolidated financial statements for the three months ended March 31, 2011. These interim consolidated financial statements should be read in conjunction with the interim consolidated financial statements and notes thereto for the three months ended March 31, 2011.

The interim consolidated financial statements were authorized for issuance by the Board of Directors on August 12, 2011.

### 3. SIGNIFICANT ACCOUNTING POLICIES

Significant accounting policies are presented in notes 3 and 4 and the impact of the new standards, including reconciliations presenting the change from previous GAAP to IFRS at January 1, 2010 and December 31, 2010 are presented in note 17 of the Company's interim consolidated financial statements for the three months ended March 31, 2011.

The impacts of the new standards, including reconciliations presenting the change from previous GAAP to IFRS as at June 30, 2010 and for the three and six months ended June 30, 2010, are presented in note 17 herein.

### 4. PROPERTY, PLANT AND EQUIPMENT

#### *Cost or deemed cost*

	<i>Oil and natural gas assets</i>	<i>Other equipment</i>	<i>Total</i>
Balance at January 1, 2010	\$ 469,762	\$ 1,713	\$ 471,475
Additions	118,140	66	118,206
Disposals	(2,407)	-	(2,407)
Balance at December 31, 2010	585,495	1,779	587,274
Additions	76,076	28	76,104
Disposals	(10,312)	-	(10,312)
Balance at June 30, 2011	\$ 651,259	\$ 1,807	\$ 653,066

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

	<i>Oil and natural gas assets</i>	<i>Other 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	25,626	70	25,696
Disposals	(5,183)	-	(5,183)
Balance at June 30, 2011	\$ 285,801	\$ 1,313	\$ 287,114

#### *Carrying amounts*

	<i>Oil and natural gas assets</i>	<i>Other equipment</i>	<i>Total</i>
At December 31, 2010	\$ 320,137	\$ 536	\$ 320,673
At June 30, 2011	\$ 365,458	\$ 494	\$ 365,952

*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 statements of operations (see note 5).

## 5. IMPAIRMENT LOSS

As a result of continued weakness in natural gas pricing at June 30, 2010, the Company tested the Deep Gas, Shallow Gas and Non-core CGUs for impairment. Based on this assessment at June 30, 2010, the carrying amount of the Deep Gas CGU was determined to be \$3.1 million lower than its recoverable amount and an impairment was recorded.

At June 30, 2011, there were no material changes in the forward curves for natural gas, oil and natural gas liquids prices from December 31, 2011, 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 is 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 is 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.

The impairment losses since January 1, 2010 recognized in each CGU were as follows:

	<i>Horizontal Oil CGU</i>	<i>Deep Gas CGU</i>	<i>Shallow Gas CGU</i>	<i>Non-Core CGU</i>	<i>Total<sup>(1)</sup></i>
Impairment loss at January 1, 2010	\$ -	\$ -	\$ 67,193	\$ -	\$ 67,193
Impairment loss for the quarter ended March 31, 2010	-	6,587	52,827	126	59,540
Impairment loss for the quarter ended June 30, 2010	-	3,112	-	-	3,112
Impairment loss for the quarter ended September 30, 2010	-	15,996	28,286	4,035	48,317
Impairment loss for the quarter ended December 31, 2010	-	5,384	35,033	1,779	42,196
Cumulative impairment loss at December 31, 2010 and June 30, 2011	\$ -	\$ 31,079	\$ 183,339	\$ 5,940	\$ 220,358
Carrying value, December 31, 2010	\$ 63,687	\$ 94,091	\$ 124,836	\$ 36,764	\$ 319,378
Carrying value, June 30, 2011	\$ 128,469	\$ 88,660	\$ 112,402	\$ 35,014	\$ 364,545

*(1) Carrying values exclude inventory and corporate assets of \$1.3 million at December 31, 2010 and \$1.4 million at June 30, 2011.*

## 6. BANK LOANS

At June 30, 2011, total bank facilities were \$135 million consisting of a \$100 million extendible revolving term credit facility, a \$10 million working capital credit facility and a \$25 million supplemental credit facility, with a syndicate of Canadian banks. The extendible revolving term credit facility and the working capital credit facility have a revolving period ending on July 11, 2012. 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 11, 2012. The supplemental facility expires on July 11, 2012, with any outstanding amounts due in full at that time.

At June 30, 2011, there were no amounts drawn under the supplemental facility. The average effective interest rate on advances under the facilities in 2011 was 5.7% (June 30, 2010 – 5.0%). The Company had \$133,500 in letters of credit outstanding at June 30, 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 1.50% to 6.00% depending on the borrowing option used and the Company's financial ratios.

## **6. BANK LOANS** *(Continued)*

Loans are secured by a floating charge debenture over all assets and guarantees by material subsidiaries. Draws over \$15 million under the supplemental facility are subject to the consent of the bank syndicate at the time of the drawdown.

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

## **7. CONVERTIBLE DEBENTURES**

On June 8, 2011, the Company issued \$46 million of convertible unsecured subordinated debentures (the "Series B Debentures") on a bought deal basis. The Series B Debentures have a face value of \$1,000, bear interest at the rate of 7.25% per annum payable semi-annually in arrears on the last day of June and December of each year commencing on December 31, 2011 and mature on June 30, 2017 ("Maturity Date"). The Series B Debentures are convertible at the holder's option at a conversion price of \$1.70 per common share (the "Conversion Price"), subject to adjustment in certain events. The Series B Debentures are not redeemable by the Corporation before June 30, 2014. On and after June 30, 2014 and prior to June 30, 2016, the Series B 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. On or after June 30, 2016 and prior to the Maturity Date, the Series B Debentures may be redeemed in whole or in part at the option of the Corporation on not more than 60 days and not less than 30 days prior notice at a price equal to their principal amount plus accrued and unpaid interest. The Series B Debentures are listed and posted for trading on the TSX under the symbol "AXL.DB.B".

The Series B Debentures were determined to be compound instruments. As the Series B 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 Series B Debentures, net of the equity component and issue costs are accreted using the effective interest rate method over the term of the Series B Debentures, such that the carrying amount of the financial liability will equal the \$46 million principal balance at maturity.

## 7. CONVERTIBLE DEBENTURES *(Continued)*

The following table indicates the convertible debenture activities:

	<i>Proceeds</i>	<i>Debt component</i>	<i>Equity component</i>
Balance, January 1, 2010	\$ -	\$ -	-
Series A Debentures 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
Series B Debentures issued pursuant to prospectus <sup>(2)</sup>	46,000	41,849	4,151
Issue costs	(2,140)	(1,947)	(193)
Deferred tax	-	-	(1,531)
Accretion expense	-	510	-
Balance, June 30, 2011	\$ 91,560	\$ 83,872	\$ 5,019

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

*(2) Includes 1,575 Series B Debentures issued to management and directors for total gross proceeds of \$1.6 million.*

## 8. DECOMMISSIONING OBLIGATIONS

	<i>June 30, 2011</i>	<i>December 31, 2010</i>
Balance at January 1	\$ 51,550	\$ 47,657
Provisions incurred	1,046	2,945
Provisions settled	(42)	(1,549)
Provisions disposed	(223)	(75)
Change in discount rate	67	634
Change in estimates	14	284
Accretion expense	856	1,654
Ending balance	\$ 53,268	\$ 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 \$53.3 million as at June 30, 2011 (December 31, 2010 – \$51.6 million) based on an undiscounted inflation-adjusted total future liability of \$75.3 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.

## 9. 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 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
<b>Balance at December 31, 2010</b>	<b>172,485,301</b>	<b>\$ 426,925</b>
Elimination of deficit	-	(255,543)
Stock options exercised	64,400	51
Transferred from contributed surplus on stock option exercise	-	27
<b>Balance at June 30, 2011</b>	<b>172,549,701</b>	<b>\$ 171,460</b>

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

*Elimination of deficit.* On May 16, 2011, the Company's shareholders approved the elimination of the Company's consolidated deficit as at January 1, 2011, the effective date of the Company's transition to IFRS, without reduction to the Company's stated capital or paid up capital.

*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 six months ended June 30, 2011 and the year ended December 31, 2010 are as follows:

	<i>June 30, 2011</i>		<i>December 31, 2010</i>	
	<i>Number of options</i>	<i>Weighted average exercise price</i>	<i>Number of options</i>	<i>Weighted average exercise price</i>
Outstanding at January 1	12,006,232	\$ 2.32	10,258,756	\$ 3.22
Granted during the period	441,100	1.18	3,950,250	1.06
Exercised during the period	(64,400)	0.79	(84,900)	0.79
Expirations during the period	(726,700)	4.93	(1,430,124)	5.78
Forfeitures during the period	(442,100)	1.07	(687,750)	1.44
<b>Ending balance</b>	<b>11,214,132</b>	<b>\$ 2.17</b>	<b>12,006,232</b>	<b>\$ 2.32</b>
<b>Exercisable, end of period</b>	<b>5,531,732</b>	<b>\$ 3.31</b>	<b>6,111,399</b>	<b>\$ 3.53</b>

## 9. SHARE CAPITAL *(Continued)*

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 exercise price</i>	<i>Weighted average remaining life (years)</i>
\$0.79 to \$0.99	2,562,100	\$ 0.79	3.2
\$1.00 to \$1.50	3,924,550	1.08	4.1
\$2.26 to \$3.35	661,950	2.68	2.2
\$3.36 to \$4.90	4,065,532	4.01	1.0
<b>Total at June 30, 2011</b>	<b>11,214,132</b>	<b>\$ 2.17</b>	<b>2.7</b>

The weighted average share price at the date of exercise for stock options exercised in 2011 was \$1.20 (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>June 30, 2011</i>	<i>June 30, 2010</i>
Fair value at grant date	\$ 0.61	\$ 0.64
Share price	\$ 1.18	\$ 1.20
Exercise price	\$ 1.18	\$ 1.20
Volatility	58%	60%
Option life	5 years	5 years
Dividends	0%	0%
Risk-free interest rate	2.7%	2.7%
Forfeiture rate	15%	15%

This estimated forfeiture rate is adjusted to the actual forfeiture rate when each tranche vests. Stock-based compensation cost of \$0.5 million (June 30, 2010 – \$0.4 million) was expensed during the six months ended June 30 2011. Stock-based compensation cost of \$0.3 million (June 30, 2010 – \$0.2 million) was expensed during the three months ended June 30 2011. In addition, stock based compensation expense of \$0.3 million (June 30, 2010 – \$0.3 million) was capitalized during the six months ended June 30, 2011. For the three months ended June 30, 2011, \$0.2 million of stock-based compensation was capitalized (June 30, 2010 – \$0.2 million).

## 10. EARNINGS (LOSS) PER SHARE

Basic and diluted earnings (loss) per share were calculated as follows:

	<i>Three months ended</i>		<i>Six months ended</i>	
	<i>June 30, 2011</i>	<i>June 30, 2010</i>	<i>June 30, 2011</i>	<i>June 30, 2010</i>
<u>Earnings (loss) for the period</u>	<u>\$ 5,932</u>	<u>\$ (4,769)</u>	<u>\$ 2,251</u>	<u>\$ (49,213)</u>
Weighted average number of common shares (basic) <i>(in thousands of shares)</i>				
Common shares outstanding at beginning of period	172,545	172,400	172,485	150,500
Effect of stock options exercised	3	-	41	-
Effect of other shares issued	-	-	-	17,629
Weighted average number of common shares (basic)	172,548	172,400	172,526	168,129
Effect of dilutive stock options	387	-	637	-
Weighted average number of common shares (diluted)	172,935	172,400	173,163	168,129
<u>Basic and diluted earnings (loss) per share</u>	<u>\$ 0.03</u>	<u>\$ (0.03)</u>	<u>\$ 0.01</u>	<u>\$ (0.29)</u>

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. For the three months ended June 30, 2011, 8,673,032 options (June 30, 2010 – 10,307,356 options) and 59,316,889 common share reserved for convertible debentures (June 30, 2010 – Nil) were excluded from calculating dilutive earnings as they were anti-dilutive. For the six months ended June 30, 2011, 8,628,032 options (June 30, 2010 – 10,307,356 options) and 59,316,889 common share reserved for convertible debentures (June 30, 2010 – Nil) were excluded from calculating dilutive earnings as they were anti-dilutive.

## 11. FINANCE INCOME AND EXPENSES

	<i>Three months ended</i>		<i>Six months ended</i>	
	<i>June 30, 2011</i>	<i>June 30, 2010</i>	<i>June 30, 2011</i>	<i>June 30, 2010</i>
Income:				
Interest income on cash equivalents	\$ 2	\$ -	\$ 5	\$ -
Other	8	6	28	64
Expenses:				
Interest and financing costs on bank loans	(891)	(709)	(1,709)	(1,394)
Interest on convertible debentures	(1,150)	-	(2,088)	-
Accretion on convertible debentures	(291)	-	(510)	-
Accretion on decommissioning obligations	(439)	(411)	(856)	(814)
Other	2	(10)	(15)	(24)
<u>Net finance expenses</u>	<u>:(2,759)</u>	<u>:(1,124)</u>	<u>:(5,145)</u>	<u>:(2,168)</u>

## 12. SUPPLEMENTAL CASH FLOW INFORMATION

Changes in non-cash working capital is comprised of:

	<i>June 30, 2011</i>	<i>June 30, 2010</i>
Source (use) of cash		
Accounts receivable and accruals	\$ 2,695	\$ 4,280
Prepaid expenses and deposits	205	833
Accounts payable and accruals	146	(555)
	<u>\$ 3,046</u>	<u>\$ 4,558</u>
Related to operating activities	\$ 1,184	\$ 3,218
Related to financing activities	\$ (34)	\$ 150
Related to investing activities	\$ 1,896	\$ 1,190

## 13. 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.

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>June 30, 2011</i>	<i>December 31, 2010</i>
Cash and cash equivalents	\$ -	\$ 4,024
Accounts receivable and accruals	18,303	20,998
	<u>\$ 18,303</u>	<u>\$ 25,022</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

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

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 June 30, 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 six months ended June 30, 2011 (June 30, 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.

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>June 30, 2011</i>	<i>December 31, 2010</i>
Oil and natural gas marketing companies	\$ 9,904	\$ 9,286
Joint venture partners	6,830	7,989
Other	1,569	3,723
	<u>\$ 18,303</u>	<u>\$ 20,998</u>

As at June 30, 2011 and December 31, 2010, the Company's accounts receivable and accruals was aged as follows:

<i>Aging</i>	<i>June 30, 2011</i>	<i>December 31, 2010</i>
Not past due	\$ 17,191	\$ 18,960
Past due by less than 120 days	935	1,706
Past due by more than 120 days	177	332
Total	<u>\$ 18,303</u>	<u>\$ 20,998</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 6. The Company also attempts to match its payment cycle with collection of oil and natural gas revenue on the 25th of each month.

### 13. 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 June 30, 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>Five to six years</i>
Non-derivative financial liabilities						
Accounts payable and accruals <sup>(1)</sup>	\$ 47,008	\$ -	\$ -	\$ -	\$ -	\$ -
Bank loans – principal <sup>(2)</sup>	-	-	45,606	-	-	-
Convertible debentures						
- Interest <sup>(1)</sup>	5,522	7,085	7,085	7,085	7,085	3,335
- Principal	-	-	-	-	50,000	46,000
<b>Total</b>	<b>\$ 52,530</b>	<b>\$ 7,085</b>	<b>\$ 52,691</b>	<b>\$ 7,085</b>	<b>\$ 57,085</b>	<b>\$ 49,335</b>

(1) Accounts payable and accruals includes \$2.1 million of interest relating to convertible debentures. The total cash interest payable in less than one year on the convertible debentures is \$7.6 million.

(2) Assumes the credit facilities are not renewed on July 11, 2012.

**(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 June 30, 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 the Company has \$50 million and \$46 million of convertible debentures with fixed interest rates of 7.5% and 7.25% respectively, maturing January 31, 2016 and June 30, 2017 (see note 7). Had the borrowing rate on bank loans been 100 basis points higher (or lower) throughout the six months ended June 30, 2011, earnings would have been affected by \$0.2 million (June 30, 2010 – \$0.2 million) 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.

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

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

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 June 30, 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	1,250 bbls/day	\$ 91.96/bbl	July 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	1,000 bbls/day	\$ 103.93/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 June 30, 2011, the Company estimates that it would have received \$2.9 million to terminate these contracts.

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:

	June 30, 2011	December 31, 2010
Assets:		
Current	\$ 1,732	\$ -
Long-term	1,166	-
Current liability	-	(1,918)
Net asset (liability) position	\$ 2,898	\$ (1,918)

The fair value of derivative contracts at June 30, 2011 would have been impacted as follows had the forward price curves used to estimated the fair value changed by:

	Effect of an increase in price on after-tax earnings	Effect of a decrease in price on after-tax earnings
Canadian \$1.00 per barrel change in the oil price	\$ (511)	\$ 511

In June 2011, the Company entered into physical sales contracts to sell 15,000 GJ per day of natural gas between July 1, 2011 and October 31, 2011 at a weighted average AECO price of \$4.06 per GJ. As of June 30, 2011, there have been no gains or losses recognized in association with these physical sales contracts.

*(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

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

natural gas assets. The Company's capital structure includes shareholders' equity of \$187.4 million, bank loans of \$45.6 million, convertible debentures with a face value of \$96.0 million and the working capital deficiency of \$25.9 million, excluding the current portion of unrealized gain 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.

	<i>June 30, 2011</i>	<i>December 31, 2010</i>
Bank loans	\$ 45,606	\$ 52,719
Current liabilities <sup>(1)</sup>	47,008	46,862
Current assets <sup>(1)</sup>	(21,150)	(28,074)
Net debt before convertible debentures	\$ 71,464	\$ 71,507
Convertible debentures (liability component)	83,872	43,460
Total net debt	\$ 155,336	\$ 114,967
Cash from operating activities in quarter	\$ 14,953	\$ 10,489
Decommissioning expenditures	16	118
Changes in non-cash working capital	(1,025)	(1,324)
Funds from operations in quarter	\$ 13,944	\$ 9,283
Annualized current quarter funds from operations	\$ 55,776	\$ 37,132
Net debt before convertible debentures to funds from operations	1.3	1.9
Total net debt to funds from operations	2.8	3.1

*(1) Excludes unrealized gains (losses) on derivative contracts.*

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

As at June 30, 2011, the Company's ratio of net debt before convertible debentures to annualized funds from operations was 1.3 to 1 (December 31, 2010 – 1.9 to 1). As at June 30, 2011, the Company's ratio of total net debt to annualized funds from operations was 2.8 to 1 (December 31, 2010 – 3.0 to 1). The high ratios reflect the capital expenditures required to make the transition from a gas weighted company to an oil weighted company. The decrease in the ratio from December 31, 2010 is the result more oil and natural gas liquids production and consequently higher funds from operations as a result of this transition. 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 further.

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

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.

### 14. RELATED PARTY TRANSACTIONS

On December 31, 2010, the Company issued 1,000 Series A 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.

On June 8, 2011, the Company issued 1,575 Series B Convertible Debentures to management and directors at a price of \$1,000 per convertible debenture for total gross proceeds of \$1.6 million as part of a \$46.0 million bought deal offering of convertible debentures.

### 15. COMMITMENTS

The Company has entered into an agreement to lease office space until November 30, 2012. Future minimum lease payments are expected to be \$0.9 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 24 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 (MMcfd)</i>		<i>Committed amount</i>
Remainder of 2011	24	\$	821
2012	19	\$	1,354
2013	8	\$	849
2014	4	\$	678
2015	4	\$	603
Thereafter	12	\$	442

## **15. COMMITMENTS** *(Continued)*

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

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

## **16. SUBSEQUENT EVENT**

On August 11, 2011, the Company disposed of property, plant and equipment for total gross proceeds of \$6.2 million.

## 17. RECONCILIATION FROM CANADIAN GAAP TO IFRS

This note sets out how the transition from CGAAP to IFRS has affected the Company's statement of financial position, comprehensive loss and shareholders' equity.

Statement of financial position at June 30, 2010:

(in thousands of dollars)	Effect of transition to IFRS								IFRS	
	Canadian GAAP	Impairment (note 17b)	Decommissioning (note 17d)	Share-based payments (note 17e)	Depletion and depreciation (note 17c)	Other PP&E adjs (note 17c)	Flow through shares (note 17f)	Deferred Taxes (note 17h)		
<b>ASSETS</b>										
Current assets:										
Cash and cash equivalents	\$ 3	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 3
Accounts receivable and accruals	18,710									18,710
Prepaid expenses and deposits	2,945									2,945
	21,658	-	-	-	-	-	-	-	-	21,658
Property, plant and equipment (note 17a)	480,411	(129,845)	1,073	(60)	15,737	482				367,798
	\$ 502,069	\$ (129,845)	\$ 1,073	\$ (60)	\$ 15,737	\$ 482	\$ -	\$ -	\$ -	\$ 389,456
<b>LIABILITIES AND EQUITY</b>										
Current liabilities:										
Accounts payable and accruals	\$ 36,334	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 36,334
Bank loans	55,608									55,608
Decommissioning obligations	34,999		14,421			181				49,601
Deferred tax liability (asset)	26,129	(32,547)	(3,336)		3,960	(196)				(5,990)
	153,070	(32,547)	11,085	-	3,960	(15)	-	-	-	135,553
Shareholders' Equity:										
Share capital	\$ 421,936	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 5,336	\$ (449)	\$ -	\$ 426,823
Contributed surplus	6,929			120						7,049
Deficit (note 17i)	(79,866)	(97,298)	(10,012)	(180)	11,777	497	(5,336)	449		(179,969)
	348,999	(97,298)	(10,012)	(60)	11,777	497	-	-	-	253,903
	\$ 502,069	\$ (129,845)	\$ 1,073	\$ (60)	\$ 15,737	\$ 482	\$ -	\$ -	\$ -	\$ 389,456

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

Reconciliation of consolidated statement of operations and comprehensive loss for the three months ended June 30, 2010:

(in thousands of dollars)	Canadian GAAP	Impairment (note 17b)	Effect of transition to IFRS				IFRS
			Decommissioning (note 17d)	Share-based payments (note 17e)	Depletion and depreciation (note 17c)	Other PP&E adjs (note 17c)	
Oil and gas sales	\$ 20,318	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 20,318
Royalties	(1,696)						(1,696)
Revenue, net of royalties	18,622	-	-	-	-	-	18,622
Gain on sale of property, plant and equipment	-					35	35
	18,622	-	-	-	-	35	18,657
Operating expenses	6,830						6,830
Transportation expenses	128						128
Depletion and depreciation	19,860				(8,392)		11,468
Impairment of property, plant and equipment	-	3,112					3,112
General and administrative expenses, including stock- based compensation	2,181			(23)		81	2,239
Loss from operating activities	(10,377)	(3,112)	-	23	8,392	(46)	(5,120)
Finance income	6						6
Finance expenses, including accretion	(1,349)		219				(1,130)
Net finance expenses	(1,343)	-	219	-	-	-	(1,124)
Loss before taxes	(11,720)	(3,112)	219	23	8,392	(46)	(6,244)
Deferred income tax benefit	(2,829)	(793)	55	-	2,112	(20)	(1,475)
Loss and comprehensive loss for the period	\$ (8,891)	\$ (2,319)	\$ 164	\$ 23	\$ 6,280	\$ (26)	\$ (4,769)

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

Reconciliation of consolidated statement of operations and comprehensive loss for the six months ended June 30, 2010:

(in thousands of dollars)	Canadian GAAP	Impairment (note 17b)	Effect of transition to IFRS				IFRS
			Decommissioning (note 17d)	Share-based payments (note 17e)	Depletion and depreciation (note 17c)	Other PP&E adjs (note 17c)	
Oil and gas sales	\$ 43,583	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 43,583
Royalties	(5,090)						(5,090)
Revenue, net of royalties	38,493	-	-	-	-	-	38,493
Gain on sale of property, plant and equipment	-					708	708
	38,493	-	-	-	-	708	39,201
Operating expenses	13,619						13,619
Transportation expenses	215						215
Depletion and depreciation	37,549				(15,737)		21,812
Impairment of property, plant and equipment	-	62,652					62,652
General and administrative expenses, including stock- based compensation	4,124			(54)		281	4,351
Loss from operating activities	(17,014)	(62,652)	-	54	15,737	427	(63,448)
Finance income	64						64
Finance expenses, including accretion	(2,662)		430				(2,232)
Net finance expenses	(2,598)	-	430	-	-	-	(2,168)
Loss before taxes	(19,612)	(62,652)	430	54	15,737	427	(65,616)
Deferred income tax benefit	(4,768)	(15,633)	108	-	3,960	(70)	(16,403)
Loss and comprehensive loss for the period	\$ (14,844)	\$ (47,019)	\$ 322	\$ 54	\$ 11,777	\$ 497	\$ (49,213)

## 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 asset 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.

Upon transition to IFRS, this resulted in a \$67.2 million reduction in property, plant and equipment. For the three months and six months ended June 30, 2010 as well as the year ended December 31, 2010 the Company recognized impairments of \$3.1 million, \$62.7 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.

For the three months ended June 30, 2010, the use of proved plus probable reserves as well as the lower net book value due to the impairments of the Company's Shallow Gas, Deep Gas and Non-core CGUs resulted in a decrease to depletion and depreciation of \$8.4 million with a corresponding increase to property, plant and equipment. For the six months ended June 30, 2010, depletion and depreciation decreased by \$15.7 million for the same reasons.

*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 six months ended June 30, 2010 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.

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

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

expense by \$0.1 million during the three months ended June 30, 2010 and \$0.3 million during the six months ended June 30, 2010 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 June 30, 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 June 30, 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 \$14.4 million from Canadian GAAP. The Company also increased the value of its plant, property and equipment for June 30, 2010 by \$1.1 million.

As a result of the change in the decommissioning obligation, accretion expense decreased by \$0.2 million during the three months ended June 30, 2010 under IFRS compared to Canadian GAAP. For the six months ended June 30, 2010, accretion expense decreased by \$0.4 million. 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. For the three months ended June 30, 2010, the Company reduced the amount of stock-based compensation expense by \$23,000 and reduced the amount capitalized by \$12,000. For the six months ended June 30, 2010, the Company reduced the amount of stock-based compensation expense by \$54,000 and reduced the amount capitalized by \$60,000. 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.

*(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

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

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. This change did not have an impact on the June 30, 2010 statement of financial position as the convertible debentures were not issued until December 31, 2010.

(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:

	<i>June 30, 2010</i>
Impairment of plant, property and equipment (note 17b)	\$ (32,547)
Depletion and depreciation (note 17c)	3,960
Decommissioning obligation (note 17d)	(3,336)
Other adjustments (note 17c)	<u>(196)</u>
<b>Decrease in deferred tax liabilities</b>	<b>\$ (32,119)</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.

The effect on the consolidated statements of operations and comprehensive loss for the three months ended June 30, 2010 was to increase the previously reported tax charge for the period by \$1.4 million. For the six months ended June 30, 2010, the effect was to decrease the previously reported tax charge by \$11.6 million.

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

	<i>June 30, 2010</i>
Impairment of plant, property and equipment (note 17b)	\$ (97,298)
Decommissioning obligations (note 17d)	(10,012)
Flow through shares (note 17f)	(5,336)
Depletion and depreciation (note 17c)	11,777
Gain on sale of plant, property and equipment (note 17c)	708
Deferred taxes on share issue costs (note 17h)	449
General and administrative expenses (note 17c)	(211)
Stock-based compensation (note 17e)	<u>(180)</u>
<b>Decrease in retained earnings</b>	<b>\$ (100,103)</b>

(j) *Adjustments to the Company's Cash Flow Statements 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 \$0.3 million to operating cash flows, with an equal and opposite effect on investing cash flows for the six months ended June 30, 2010 and \$0.1 million for the three months ended June 30, 2010.

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

## Auditors

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## Independent Engineers

GLJ Petroleum Consultants

## Legal Counsel

Bennett Jones LLP

## Registrar & Transfer Agent

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The Toronto Stock Exchange  
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Brian H. Dau  
President & Chief Executive Officer

David M. Spyker  
Chief Operating Officer

M. Darlene Wong  
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Officer & Secretary

Blaine M. Chicoine  
Vice President, Operations

Sandra M. Drinnan  
Vice President, Land

Philip A. Harvey  
Vice President, Exploitation

Jamie A. Marshall  
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## 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