ANDERSON
ENERGY LTD.

2011 Financial Report

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Anderson Energy Announces 2011 Fourth Quarter and Year End Results

Calgary, Alberta, March 19, 2012 - Anderson Energy Ltd. ("Anderson" or the "Company") (TSX:AXL) is pleased to announce its operating and financial results for the fourth quarter and year ended December 31, 2011.

HIGHLIGHTS

- Funds from operations in the fourth quarter were $17.0 million, up 83% from the fourth quarter of 2010, and represented Anderson's best quarter in 2011. Funds from operations for 2011 were $54.5 million, up 49% from 2010. Production in the fourth quarter of 2011 was 7,933 BOED.
- The Company's netback per BOE increased throughout the year to $29.88 per BOE in the fourth quarter of 2011 compared to $25.89 per BOE for the year and $16.86 per BOE in the fourth quarter of 2010. Cardium netbacks averaged $62.56 per BOE in the fourth quarter of 2011 and $61.30 per BOE for the year.
- Oil and NGL production averaged 2,837 bpd in the fourth quarter, up 56% from the prior year. Oil represented 2,122 bpd of total production and was 114% higher than last year. Oil and NGL production averaged 2,422 bpd for the year, up 76% from 2010.
- Proved plus probable ("P&P") BOE reserves increased 8% from December 31, 2010 to 34.3 MMBOE.
- P&P reserves replacement was 656% for oil and 572% for oil and NGL for additions and revisions. On a BOE basis, Anderson replaced 310% of production with P&P reserves additions in 2011.
- Cardium P&P reserves increased by 177% to 13.0 MMBOE representing 38% of total P&P reserves volumes and 62% of total P&P reserves value on a pre-tax 10% net present value ("NPV 10") basis.
- Anderson's total P&P pre-tax NPV 10 at December 31, 2011 was $355.3 million, 31% higher than at December 31, 2010 even though lower natural gas price forecasts used by GLJ Petroleum Consultants Ltd. ("GLJ") reduced this total by approximately $69 million.
- Finding, development and acquisition ("FD&A") costs in 2011, including changes in future development capital, additions, dispositions and technical revisions but excluding natural gas related economic factors were $37.15 per BOE total proved and $26.26 per BOE total P&P.
- Anderson's Cardium horizontal oil location inventory is approximately 260 gross (166 net) locations, a 28% increase since reported on November 15, 2011. Net prospect inventory has increased as a result of information gained from new discoveries as well as additional farm-in transactions.
- One of the Cardium development wells drilled in the first quarter tested at 1,437 BOED (74% oil and NGL), and is expected to be on-stream in the second quarter of 2012.
- As previously announced, in response to the lack of market recognition of the inherent value in the Company's asset base, the Company's board of directors (the "Board of Directors") has initiated a process to identify, examine and consider a range of strategic alternatives with a view to enhancing shareholder value. Anderson has engaged BMO Capital Markets and RBC Capital Markets as financial advisors to assist in this process.

FINANCIAL AND OPERATING HIGHLIGHTS

(thousands of dollars, unless otherwise stated)	Three months ended December 31 2011	2010*	% Change	Year ended December 31 2011	2010*	% Change
Oil and gas sales**	$ 32,627	$ 23,946	36%	$ 118,292	$ 86,457	37%
Revenue, net of royalties**	$ 28,457	$ 21,690	31%	$ 104,486	$ 77,446	35%
Funds from operations	$ 16,997	$ 9,282	83%	$ 54,464	$ 36,516	49%
Funds from operations per share						
Basic and diluted	$ 0.10	$ 0.05	100%	$ 0.32	$ 0.21	52%
Earnings (loss) before effect of impairment or reversals thereof	$ (4,939)	$ (4,864)	(2%)	$ 3,979	$ (10,115)	139%
Earnings (loss) per share before effect of impairment or reversals thereof						
Basic and diluted	$ (0.03)	$ (0.03)	-	$ 0.02	$ (0.06)	133%
Loss	$ (32,167)	$ (36,545)	12%	$ (22,444)	$ (124,787	82%
Loss per share						
Basic and diluted	$ (0.19)	$ (0.21)	10%	$ (0.13)	$ (0.73)	82%
Capital expenditures, including acquisitions net of dispositions	$ 40,924	$ 26,240	56%	$ 159,275	$ 111,509	43%
Bank loans plus cash working capital deficiency				$ 132,656	$ 71,507	86%
Convertible debentures				$ 84,796	$ 43,460	95%
Shareholders' equity				$ 163,420	$ 181,895	(10%)
Average shares outstanding *(thousands)*:						
Basic	172,550	172,464	-	172,538	170,299	1%
Diluted	172,550	172,464	-	172,538	170,299	1%
Ending shares outstanding *(thousands)*				172,550	172,485	-
Average daily sales:						
Natural gas *(Mcfd)*	30,576	38,479	(21%)	31,620	37,124	(15%)
Oil *(bpd)*	2,122	992	114%	1,743	601	190%
NGL *(bpd)*	715	823	(13%)	679	778	(13%)
Barrels of oil equivalent *(BOED)*	7,933	8,228	(4%)	7,692	7,566	2%
Average prices:						
Natural gas *($/Mcf)*	$ 3.20	$ 3.48	(8%)	$ 3.60	$ 3.96	(9%)
Oil *($/bbl)*	$ 96.33	$ 77.62	24%	$ 93.05	$ 73.62	26%
NGL *($/bbl)*	$ 72.71	$ 58.87	24%	$ 69.81	$ 55.22	26%
Barrels of oil equivalent *($/BOE)***	$ 44.70	$ 31.63	41%	$ 42.13	$ 31.31	35%
Realized loss on derivative contracts *($/BOE)*	$ (0.37)	$ (0.17)	(118%)	$ (0.22)	$ (0.05)	(340%)
Royalties *($/BOE)*	$ 5.71	$ 2.98	92%	$ 4.92	$ 3.26	51%
Operating costs *($/BOE)*	$ 8.30	$ 11.32	(27%)	$ 10.52	$ 10.34	2%
Transportation costs *($/BOE)*	$ 0.44	$ 0.30	47%	$ 0.58	$ 0.22	164%
Operating netback *($/BOE)*	$ 29.88	$ 16.86	77%	$ 25.89	$ 17.44	48%
Reserves *(MBOE)*:						
Total proved				20,945	20,117	4%
Total proved plus probable				34,325	31,687	8%
Wells drilled *(gross)*	11	6	83%	52	49	6%

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

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

CARDIUM HORIZONTAL OIL DRILLING

In the fourth quarter of 2011, Anderson drilled 10 gross (9.6 net capital, 8.3 net revenue) successful Cardium horizontal oil wells. From May 1, 2010 to December 31, 2011, the Company has drilled 72 gross (54 net revenue) successful Cardium oil wells.

NEW CARDIUM DISCOVERIES

In the fourth quarter of 2011, Anderson evaluated four new areas through the drilling of five Cardium horizontal wells. Anderson drilled four horizontal oil wells in three new areas outside of its existing core areas in Willesden Green, Garrington and Ferrier. In one of the new areas, a development well tested at 1,437 BOED (74% oil and NGL) over a four day test period[1]. This well is estimated to be on-stream in the second quarter of 2012. The Company also drilled a dry hole at Carrot Creek. This is the only dry hole for the Company after drilling 72 successful oil wells in this play. The Company's land position in Carrot Creek was limited to one section of land.

FERRIER CARDIUM OIL POOL DEVELOPMENT UPDATE

Four gross (2.5 net revenue) Cardium horizontal oil wells are on production. Anderson has expanded its oil battery gas compression system and will be drilling two additional wells in the third quarter of 2012.

CARDIUM ENHANCED OIL RECOVERY "EOR"

The Company has completed a computer reservoir simulation of the Garrington field to determine the most appropriate fluid and scheme for enhanced recovery of Cardium oil using horizontal oil drilling. The conclusion of the study is that a gas flood is the most economical scheme and could potentially double recovery in this oil pool. The Company will be using its uphole Edmonton Sands gas and/or Cardium solution gas as an injection fluid to enhance recovery. The earliest injection date could be in the last quarter of 2012, subject to regulatory approval and gas compression installation.

CARDIUM HORIZONTAL OIL PROSPECT INVENTORY

The Company has grown its drill-ready net prospect inventory by 28% since November 15, 2011 as outlined below:

Cardium Prospect Area	*Gross*	*Net **
Garrington	91	64
Willesden Green	72	52
Ferrier	36	22
Pembina	61	28
Total Cardium inventory	260	166
Oil wells drilled to March 16, 2012	75	56
Remaining Cardium inventory, March 16, 2012	185	110

** Net is net revenue interest*

Net prospect inventory has increased as a result of information gained from new discoveries as well as additional farm-in transactions.

By the end of the first quarter of 2012, the Company will have completed all of its Cardium facility construction projects. Future drilling of wells from the Cardium inventory outlined above can be simply connected to the new Company owned infrastructure. The Company's Cardium acreage position is 131 gross (81 net) sections.

(1) Readers are cautioned that the test results may not be indicative of long-term well performance or of ultimate recovery.

OTHER ZONE HORIZONTAL OIL PROSPECT INVENTORY

The Company has identified a prospect inventory for light oil drilling in the Second White Specs ("SWS"), Viking and Belly River zones in Central Alberta. At this time, the Company has not drilled any horizontal wells into these horizons. Many of the wells identified could be connected to existing Cardium oil infrastructure owned by the Company.

A total of 91 gross (48 net) horizontal drilling locations have been identified in the SWS, Viking and Belly River zones in Central Alberta.

The Company has a total of 134 gross (70.6 net) sections of land in the SWS fairway. The drilling inventory mentioned above for the SWS is based on the Company's interpretation for horizontal oil prospectivity in the silt portion of the SWS. The Company used geological well control and successful industry horizontal oil analogs to identify the prospects in the Viking and Belly River.

PRODUCTION

The Company met its 2011 production target with 2011 production of 7,692 BOED. Production in the fourth quarter was 7,933 BOED. Fourth quarter 2011 oil and natural gas liquids production set a new record and averaged 2,837 barrels per day in the quarter. All of the operated Cardium wells successfully drilled in the fourth quarter of 2011 have been placed on production to date in 2012.

2012 CAPITAL PROGRAM

For the first half of 2012, Anderson estimates its capital program to be $18.3 million ($12.0 million net of proceeds on dispositions), dedicated exclusively to its Cardium horizontal drilling program. After spring break up, the Company will revisit its 2012 capital program.

COMMODITY HEDGING CONTRACTS

Crude Oil. As part of its price management strategy, the Company has added to its fixed price swap contracts based on the NYMEX crude oil price in Canadian dollars. As of March 16, 2012, the average volumes and prices for these contracts are summarized below:

Period	*Weighted average volume (bpd)*	*Weighted average WTI Canadian ($/bbl)*
January 2012	1,500	104.63
February to March 2012	2,000	104.41
April to December 2012	1,500	103.87

The Company entered into hedging contracts to protect its capital program. 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 Company has not hedged any natural gas volumes at this time.

PROPERTY DISPOSITION UPDATE

In the first quarter of 2012, Anderson has entered into agreements and/or has closed the sale of 219 BOED (75% natural gas) of production based on January 2012 production estimates, for total consideration of $6.3 million (subject to adjustments). These properties are considered by the Company to be non-core and of no strategic value to Anderson. Proceeds will be used to retire bank debt. The Company's disposition process concluded later than planned and did not reduce 2011 capital expenditures as originally expected.

RESERVES

GLJ, an independent reserves evaluator, has completed a reserves report (the “GLJ Report”) of all of the Company’s oil and natural gas properties effective December 31, 2011, prepared in accordance with procedures and standards contained in the Canadian Oil and Gas Evaluation (“COGE”) Handbook. The reserves definitions used in preparing the report are those contained in the COGE Handbook and the Canadian Securities Administrators National Instrument 51-101. As of December 31, 2011, the Company had 12.6 MMBOE PDP (33% oil and NGL), 20.9 MMBOE TP (29% oil and NGL) and 34.3 MMBOE P&P (31% oil and NGL) reserves. The GLJ price forecast used in the evaluation is shown in Management’s Discussion and Analysis for the year ended December 31, 2011.

P&P reserves replacement was 656% for oil and 572% for oil and NGL for additions and revisions. On a BOE basis, Anderson replaced 310% of production with P&P reserves additions in 2011. The Company's P&P BOE reserves increased 8% since December 31, 2010.

P&P reserves from the Cardium drilling program are 13.0 MMBOE at December 31, 2011 representing an increase of 177% from 4.7 MMBOE at December 31, 2010. Cardium reserves represent 38% of total P&P reserves volumes and 62% of total P&P reserves value on a pre-tax NPV 10 basis. Edmonton Sands dry shallow gas reserves are less than 9% of the pretax NPV 10 value of the reserves. The Edmonton Sands farm-in, as disclosed in note 21 of the Company’s consolidated financial statements for the years ended December 31, 2011 and December 31, 2010, is included in the GLJ Report.

Since the inception of the Cardium play two years ago and including production of 826 MBOE, the Company has added 13.8 MMBOE of P&P reserves with its Cardium drilling program. At December 31, 2011, GLJ has recognized P&P reserves for 101.3 net producing wells and undeveloped locations compared to 36 net producing wells and undeveloped locations at December 31, 2010. Anderson estimates that it has an additional 64 net Cardium drilling locations without reserves booked.

SUMMARY OF OIL AND GAS RESERVES

	December 31, 2011					*December 31, 2010*				
	Oil *(Mbbls)*	NGL *(Mbbls)*	Gas *(MMcf)*	Total *(MBOE)*	Pre-tax NPV 10 *($M)*	Oil *(Mbbls)*	NGL *(Mbbls)*	Gas *(MMcf)*	Total *(MBOE)*	Pre-tax NPV 10 *($M)*
Proved developed producing	2,576	1,534	50,783	12,573	207,906	1,303	1,376	52,498	11,428	166,058
Proved developed producing and proved developed non-producing	2,617	1,556	57,315	13,724	215,272	1,471	1,426	59,955	12,889	175,619
Total proved	4,124	1,982	89,042	20,945	233,078	2,226	1,673	97,313	20,117	184,248
Proved plus probable	7,444	3,316	141,389	34,325	355,311	3,908	2,676	150,621	31,687	271,469

FD&A costs in 2011, including changes in future development capital, additions, acquisitions, dispositions and technical revisions but excluding natural gas related economic factors were $37.15 per BOE total proved and $26.26 per BOE total P&P, compared to $22.30 per BOE total proved and $22.35 per BOE total P&P in 2010 calculated in a similar manner. The Company's 2011 costs were higher than 2010, as the Company effectively completed its Cardium infrastructure build-out. With the Company's average 2011 Cardium operating netback of $61.30 per BOE, a P&P FD&A cost of $26.26 per BOE provides a recycle ratio of 2.3 times, which is very acceptable for light oil capital investments. The Company's three year FD&A is calculated to be $24.78 per BOE total proved and $20.32 per BOE total P&P, which represents two years of Cardium light oil drilling and one year (2009) of Edmonton Sands shallow gas drilling. The Company believes that finding and development costs should include acquisition and disposition volumes and changes in future development capital for acquisitions and dispositions as it is a very useful and commonly used reference for its shareholders. The Company does not think that the three year calculation is meaningful as it has shifted its entire focus to light oil horizontal drilling. More discussion on FD&A is included in the MD&A. The aggregate of the exploration and development costs incurred in the most recent financial year and the change during that year in estimated future development costs generally will not reflect total finding and development costs related to reserves additions for that year.

Oil and NGL reserves now represent 33% of the Company's PDP, 29% of TP and 31% of the P&P reserves as compared to 23%, 19% and 21% respectively at December 31, 2010. The Company increased PDP, TP and P&P oil and NGL reserves by 53%, 57% and 63% in the past year.

The Company's reserve life indices are 7.5 years TP and 12.2 years P&P based on 2011 annual production.

Anderson's total P&P pre-tax NPV 10 at December 31, 2011 was $355.3 million, 31% higher than at December 31, 2010. At December 31, 2011, declines of $0.97 per MMBTU in the natural gas price forecasts used by GLJ for 2012 to 2021 reduced total P&P NPV 10 by approximately $69 million.

In 2011, the Company experienced positive technical revisions of 0.9 MMBOE TP and 0.7 MMBOE P&P. These were offset by negative economic factors of 1.6 MMBOE TP and 3.3 MMBOE P&P. The negative economic factors related to undeveloped natural gas reserves in the Edmonton Sands and outside operated coal bed methane properties. The negative economic factors were due to reductions of up to 26% in GLJ's natural gas price outlook for the years 2012 to 2020. This was partially offset by the fact that there was improved performance in the proved developed producing category for the Edmonton Sands resulting in positive revisions.

	Total Proved Developed Producing (MBOE)	*Total Proved (MBOE)*	*Total Proved plus Probable (MBOE)*
Opening Balance, December 31, 2010	11,428	20,117	31,687
Additions	2,843	4,692	8,526
Dispositions	(272)	(337)	(537)
Technical revisions	1,382	901	714
Production	(2,808)	(2,807)	(2,807)
Economic factors	-	(1,621)	(3,258)
Closing Balance, December 31, 2011	12,573	20,945	34,325

FINANCIAL RESULTS

Capital expenditures were $40.9 million (net of proceeds on dispositions of $0.1 million) in the fourth quarter of 2011 with $32.2 million spent on drilling and completions and $7.4 million spent on facilities. This compares to capital expenditures of $26.2 million in the fourth quarter of 2010.

Anderson's funds from operations were $17.0 million in the fourth quarter of 2011 compared to $9.3 million in the fourth quarter of 2010. The Company's average crude oil and natural gas liquids sales prices in the fourth quarter of 2011 were $96.33 and $72.71 per barrel compared to $77.62 and $58.87 respectively per barrel in the fourth quarter of 2010. The Company has entered into fixed price oil swaps for 2012. The Company's unrealized gain on its oil hedges was $3.3 million for the year ended December 31, 2011. The Company's average natural gas sales price was $3.20 per Mcf in the fourth quarter of 2011 compared to $3.48 per Mcf in fourth quarter of 2010 and included a $0.4 million gain related to physical fixed price natural gas sales contracts. The Company recorded a loss of $32.2 million in the fourth quarter of 2011 primarily due to the impairment of its natural gas properties related to reductions in the natural gas price forecasts used by GLJ. The Company's operating netback was $29.88 per BOE in the fourth quarter of 2011 compared to $16.86 per BOE in the fourth quarter of 2010. The increase in the operating netback was primarily due to the increase in oil and NGL prices and oil volumes. Anderson's netback for its Cardium horizontal properties in the year ended December 31, 2011 was $61.30 per BOE compared to $15.42 per BOE for the remainder of its properties (exclusive of hedging). Anderson's operating netback for its Cardium properties was $62.56 per BOE in the fourth quarter of 2011.

	Average wellhead natural gas price ($/Mcf)	*Revenue ($/BOE)*	*Operating netback ($/BOE)*	*Funds from operations ($/BOE)*
2009 *	3.95	27.74	15.07	11.26
2010 *	3.96	31.31	17.44	13.22
First quarter of 2011	3.58	36.80	21.96	15.63
Second quarter of 2011	3.79	44.71	25.47	19.75
Third quarter of 2011	3.85	42.16	26.10	18.71
Fourth quarter of 2011	3.20	44.70	29.88	23.29

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

SHUT-IN OF NATURAL GAS PROPERTIES

In response to low natural gas prices, the Company plans to shut-in approximately 500 Mcfd of production from natural gas properties with higher operating costs. In a higher price environment, these natural gas wells could easily be returned to production.

STRATEGY

The Company is focused on converting its asset base to be more than 50% oil and NGL production. Proceeds from the disposition of minor properties are being dedicated to reduce bank debt. Crude oil pricing remains strong, but volatile and Anderson has increased its hedge position to help protect its capital program and its shareholders from volatile oil markets.

Anderson has substantially grown its Cardium drilling inventory in the last three months and with the completion of the infrastructure projects, newly drilled Cardium horizontal wells can be easily connected to these gathering systems. Unlike natural gas markets, oil prices continue to remain strong and the economics of the Cardium oil drilling programs are excellent.

Upon filing its 2011 annual Form 40-F, the Company intends to file a Form 15 with the U.S. Securities and Exchange Commission (the “SEC”) to suspend the Company's future SEC reporting obligations.

STRATEGIC ALTERNATIVES

As previously announced, the Board of Directors has initiated a process to identify, examine and consider a range of strategic alternatives available to the Company with a view to enhancing shareholder value. The strategic alternatives considered may include, but are not limited to, a sale of all or a material portion of the assets of Anderson, either in one transaction or in a series of transactions, the outright sale of the Company, or a merger or other strategic transaction involving Anderson and a third party. The Board of Directors believes that the Company’s shares trade at a significant discount to the value of the underlying assets, especially given its high quality Cardium oil production base, prospective Cardium horizontal oil drilling inventory and approximately $497 million in tax pools. The Board of Directors has established a special committee comprised of independent directors of the Company to oversee this process and has retained BMO Capital Markets and RBC Capital Markets as its financial advisors to assist the Special Committee and the Board of Directors with the process. The process was not initiated as a result of any particular offer.

It is Anderson’s current intention to not disclose developments with respect to its strategic alternatives process unless and until the Board of Directors has approved a specific transaction or otherwise determines that disclosure is necessary in accordance with applicable law. The Company cautions that there are no assurances or guarantees that the process will result in a transaction or, if a transaction is undertaken, the terms or timing of such a transaction. The Company has not set a definitive schedule to complete its evaluation.

Brian H. Dau
President & Chief Executive Officer
March 19, 2012

Management's Discussion and Analysis

The following management's discussion and analysis is dated March 16, 2012 and should be read in conjunction with the audited consolidated financial statements of Anderson Energy Ltd. ("Anderson" or the "Company") for the years ended December 31, 2011 and 2010. The consolidated financial statements have been prepared 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"). Previously, the Company prepared its 2010 annual consolidated financial statements in accordance with Canadian Generally Accepted Accounting Principles ("CGAAP"). The impact of the transition to IFRS on the Company's previously reported financial position and financial results for 2010 is discussed below under the caption "Adoption of IFRS". The adoption of IFRS had no material impact the Company's strategic decisions, business practices or prospects, operations, key agreements including debt agreements and covenants or cash flow from operations, before changes in non-cash working capital.

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 and the realized gains/losses on derivative contracts less royalties, operating 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 and therefore are referred to as non-GAAP measures.

All references to dollar values are to Canadian dollars unless otherwise stated. Production volumes are measured upon sale unless otherwise noted and reserves numbers are stated before deducting Crown or lessor royalties.

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

REVIEW OF FINANCIAL RESULTS

Overview. For the year ended December 31, 2011, funds from operations were $54.5 million ($0.32 per share), up 49% from 2010 as a result of the Company's focus on Cardium light oil drilling. Sales volumes averaged 7,692 BOED, slightly higher than in the previous year.

Capital additions, net of dispositions were $159.3 million for the year ended December 31, 2011. During the year, the Company drilled 51 gross (43.8 net capital) successful oil wells and one dry hole. During the fourth quarter of 2011, the Company drilled 10 gross (9.6 net capital) successful Cardium light oil wells in addition to the one 100% dry hole. The Company also tied in 12 gross (9.3 net revenue) Cardium light oil wells in the fourth quarter of 2011 and completed battery and solution gas compression projects at Garrington, Ferrier, Willesden Green and other areas. The Company's finding, development and acquisition costs, including changes in future development capital, additions, dispositions and technical revisions but excluding natural gas related economic factors were $26.26 per BOE on a proved plus probable basis for 2011.

Bank loans plus cash working capital deficiency (excludes unrealized gain on derivative contracts) was $132.7 million at December 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, was used to finance the Company's capital programs.

Revenue and Production. In 2010, the Company changed its focus to developing oil prospects in light of the continued depressed natural gas market and increased oil sales from development activities has positively affected revenues during 2011. Oil sales and natural gas liquids, which have higher sales prices and netbacks than natural gas, have taken a larger role in the Company's sales mix. For the 2011 financial year, oil and natural gas liquids revenue represented 65% of total revenue (2010 – 37%) whereas in the fourth quarter of 2011, oil and natural gas liquids revenue represented 72% of total revenue (2010 – 48%).

Oil sales for the year ended December 31, 2011 averaged 1,743 bpd compared to 601 bpd for the year ended December 31, 2010. Oil sales averaged 2,122 bpd in the fourth quarter of 2011 compared to 1,709 bpd in the third quarter of 2011 and 992 bpd in the fourth quarter of 2010. The increase in 2011 fourth quarter volumes is due to new oil production from 12 gross (9.3 net) Cardium horizontal light oil wells, which were brought on-stream during the quarter.

The Company suspended its shallow gas drilling program after the first quarter of 2010 because of low natural gas prices. Accordingly, natural production declines were not replaced, resulting in decreases in gas sales throughout 2011. Gas sales volumes for the year ended December 31, 2011 decreased to an average of 31.6 MMcfd from 37.1 MMcfd last year due to the suspension of shallow gas drilling after the first quarter of 2010. The central Alberta area, centered around the Sylvan Lake area and northwest to Pembina, remains the Company's largest area of production, with gas sales averaging 30.2 MMcfd (35.6 MMcfd during 2010). Gas sales volumes averaged 30.6 MMcfd in the fourth quarter of 2011 compared to 30.0 MMcfd in the third quarter of 2011 and 38.5 MMcfd in the fourth quarter of 2010.

Natural gas liquids sales for the year ended December 31, 2011 averaged 679 bpd compared to 778 bpd for the year ended December 31, 2010. Natural gas liquids sales averaged 715 bpd in the fourth quarter of 2011 compared to 636 bpd in the third quarter of 2011 and 823 bpd in the fourth 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 three and twelve months ended December 31, 2011 and 2010.

OIL AND NATURAL GAS SALES

(thousands of dollars)	Three months ended December 31 2011	Three months ended December 31 2010	Year ended December 31 2011	Year ended December 31 2010
Natural gas	$ 8,589	$ 12,320	$ 40,377	$ 52,304
Gain on fixed price natural gas contracts	410	-	1,228	1,302
Total natural gas	8,999	12,320	41,605	53,606
Oil[(1)]	18,807	7,081	59,184	16,142
NGL	4,785	4,459	17,302	15,672
Royalty and other	36	86	201	1,037
Total oil and gas sales[(1)]	$ 32,627	$ 23,946	$ 118,292	$ 86,457

(1) The three month numbers exclude the realized and unrealized losses on derivative contracts of $0.3 million and $7.9 million respectively during 2011 (2010 – $0.1 million and $1.9 million losses respectively). The yearly numbers exclude the realized loss of $0.6 million and unrealized gain on derivative contracts of $3.3 million during 2011 (2010 – $0.1 million loss and $1.9 million loss respectively).

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PRODUCTION

	Three months ended December 31 2011	Three months ended December 31 2010	Year ended December 31 2011	Year ended December 31 2010
Natural gas *(Mcfd)*	30,576	38,479	31,620	37,124
Oil *(bpd)*	2,122	992	1,743	601
NGL *(bpd)*	715	823	679	778
Total *(BOED)*	7,933	8,228	7,692	7,566

PRICES

	Three months ended December 31 2011	Three months ended December 31 2010	Year ended December 31 2011	Year ended December 31 2010
Natural gas *($/Mcf)*[(1)]	$ 3.20	$ 3.48	$ 3.60	$ 3.96
Oil *($/bbl)*[(2)]	96.33	77.62	93.05	73.62
NGL *($/bbl)*	72.71	58.87	69.81	55.22
Total *($/BOE)*[(2)(3)]	$ 44.70	$ 31.63	$ 42.13	$ 31.31

(1) Includes gain on fixed price natural gas contracts of $1.2 million in 2011 (2010 - $1.3 million).
(2) The three month numbers exclude the realized and unrealized losses on derivative contracts of $0.3 million and $7.9 million respectively during 2011 (2010 – $0.1 million and $1.9 million losses respectively). The yearly numbers exclude the realized loss of $0.6 million and unrealized gain on derivative contracts of $3.3 million during 2011 (2010 – $0.1 million loss and $1.9 million loss respectively).
(3) Includes royalty and other income classified with oil and gas sales.

World and North American benchmark prices for oil have improved dramatically since 2010, and have positively impacted the oil and natural gas liquids prices realized by the Company in 2011 relative to 2010. However, crude oil prices remain volatile and as described below, the Company has entered into certain derivative contracts to partially hedge recent oil price levels to protect its capital program. Natural gas prices remained low throughout 2011 as well as 2010, and current market conditions including high supply and low demand for natural gas in North America have continued to negatively impact the prices for natural gas.

The above noted oil price in 2011 does not include a realized loss on derivative contracts of $0.6 million (December 31, 2010 – $0.1 million loss). The realized oil price including this loss was $94.94 per barrel for the fourth quarter of 2011 and $92.06 per barrel for the year ended December 31, 2011 compared to $76.18 per barrel for the fourth quarter of 2010 and $73.02 per barrel for the year ended December 31, 2010.

The natural gas price in 2011 includes a gain on fixed price natural gas contracts of $1.2 million (December 31, 2010 – $1.3 million). The 2011 natural gas price before the gain was $3.50 per Mcf (December 31, 2010 – $3.86 per Mcf). The fixed price natural gas contracts concluded at the end of October 2011 which contributed to the drop in prices realized during the fourth quarter of 2011 ($3.20 per Mcf) relative to the third quarter of 2011 ($3.85 per Mcf) and the fourth quarter of 2010 ($3.48 per Mcf). The Company is currently selling all of its gas production at the average daily index price. Average natural gas prices realized by the Company to date during 2012 have been less than $2.50 per Mcf.

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

Period	*Weighted average volume (bpd)*	*Weighted average WTI Canadian ($/bbl)*
January 1, 2012 to March 31, 2012	1,500	104.63
April 1, 2012 to December 31, 2012	1,000	103.93

Derivative contracts had the following impact on the consolidated statements of operations:

	Three months ended December 31		*Year ended December 31*	
(thousands of dollars)	*2011*	*2010*	*2011*	*2010*
Realized loss on derivative contracts	$ (271)	$ (131)	$ (624)	$ (131)
Unrealized gain (loss) on derivative contracts	(7,864)	(1,918)	3,302	(1,918)
Total gain (loss) on derivative contracts	$ (8,135)	$ (2,049)	$ 2,678	$ (2,049)

In January 2012, the Company entered into fixed price swap contracts for an average of 500 barrels per day of crude oil for February to December 2012 at a weighted average NYMEX crude oil price of Canadian $103.75 per barrel.

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 recognized a gain of $1.2 million on these contracts during the year ended December 31, 2011. The Company had no fixed price natural gas contracts in place at December 31, 2011.

Royalties. For the year ended December 31, 2011, the average rate for royalties was 11.8% (December 31, 2010 – 10.4%) of revenue. For the fourth quarter of 2011, the average rate for royalties was 12.8% of revenue compared to 12.4% of revenue in the third quarter of 2011 and 9.4% of revenue in the fourth quarter of 2010. The increase in the average royalty rate for the year and quarter ended December 31, 2011 is due to the following: (i) an estimated reduction in gas cost allowance for 2011 due to lower crown royalties as a result of lower natural gas prices, production and expenditures and (ii) new production from non-crown properties that carry higher royalty rates. Offsetting this, oil wells drilled on Crown lands during 2011 qualified for royalty incentives that reduced average Crown royalties during the year. These incentives reduce Crown royalties for periods of up to 30 months from initial production, after which Crown royalties are expected to increase from current levels.

Royalties as a percentage of total oil and gas sales are highly sensitive to prices and adjustments to gas cost allowance and so royalty rates can fluctuate from quarter to quarter.

	Three months ended December 31		*Year ended December 31*	
	2011	*2010*	*2011*	*2010*
Gross Crown royalties	8.0%	10.9%	9.2%	12.5%
Gas cost allowance	(1.5%)	(3.7%)	(4.2%)	(7.2%)
Other royalties	6.3%	2.2%	6.8%	5.1%
Total royalties	12.8%	9.4%	11.8%	10.4%
Total royalties *($/BOE)*	$ 5.71	$ 2.98	$ 4.92	$ 3.26

Operating Expenses. Operating expenses were $10.52 per BOE for the year ended December 31, 2011 compared to $10.34 per BOE for the year ended December 31, 2010. Operating expenses were $8.30 per BOE in the fourth quarter of 2011 compared to $11.22 per BOE in the third quarter of 2011 and $11.32 per BOE in the fourth quarter of 2010. The decrease in operating expenses for the fourth quarter of 2011 is primarily due to a reduction in estimated accrued liabilities related to certain gas plant processing fees from earlier periods.

Transportation Expenses. For the year ended December 31, 2011, transportation expenses were $0.58 per BOE (December 31, 2010 – $0.22 per BOE). For the fourth quarter of 2011, transportation expenses were $0.44 per BOE compared to $0.89 per BOE in the third quarter of 2011 and $0.30 per BOE in the fourth quarter of 2010. The increase in transportation expenses in 2011 relative to 2010 is the result of the costs of trucking higher volumes of clean oil to the point of sale. Oil production was 23% of total production in 2011 compared with 8% in 2010. Although higher in 2011 than 2010, transportation costs decreased in the fourth quarter of 2011 relative to the third quarter of 2011 due to the direct tie-in of the Garrington battery to a newly constructed lateral pipeline in October, thereby replacing the trucking charges with a pipeline tariff. Also, certain actual costs in excess of estimated costs for prior periods were recorded in the third quarter of 2011, representing approximately $0.25 per BOE during that quarter.

OPERATING NETBACK

	Three months ended December 31		*Year ended December 31*	
(thousands of dollars)	*2011*	*2010*	*2011*	*2010*
Revenue[(1)]	$ 32,627	$ 23,946	$ 118,292	$ 86,457
Realized loss on derivative contracts	(271)	(131)	(624)	(131)
Royalties	(4,170)	(2,256)	(13,806)	(9,011)
Operating expenses	(6,060)	(8,575)	(29,533)	(28,537)
Transportation expenses	(322)	(224)	(1,626)	(611)
Operating netback	$ 21,804	$ 12,760	$ 72,703	$ 48,167
Sales volume *(MBOE)*	729.9	757.0	2,807.5	2,761.5
Per BOE				
Revenue[(1)]	$ 44.70	$ 31.63	$ 42.13	$ 31.31
Realized loss on derivative contracts	(0.37)	(0.17)	(0.22)	(0.05)
Royalties	(5.71)	(2.98)	(4.92)	(3.26)
Operating expenses	(8.30)	(11.32)	(10.52)	(10.34)
Transportation expenses	(0.44)	(0.30)	(0.58)	(0.22)
Operating netback per BOE	$ 29.88	$ 16.86	$ 25.89	$ 17.44

(1) Includes royalty and other income classified with oil and gas sales. Excludes unrealized loss on derivative contracts of $7.9 million for the three months ended December 31, 2011 and a $3.3 million gain pertaining to fixed price crude oil swaps for the twelve months ended December 31, 2011 (December 31, 2010 - $1.9 million loss and $1.9 million loss respectively).

Depletion and Depreciation. Depletion and depreciation was $52.9 million ($18.85 per BOE) for the year ended December 31, 2011 compared to $45.7 million ($16.53 per BOE) in 2010. Depletion and depreciation was $15.0 million ($20.49 per BOE) in the fourth quarter of 2011 compared to $12.3 million ($18.16 per BOE) in the third quarter of 2011 and $13.2 million ($17.45 per BOE) in the fourth quarter of 2010. The increase in depletion and depreciation for the year and the fourth quarter of 2011 compared to the same periods of 2010 is due to higher capital costs associated with oil properties and increased production from these properties.

Impairment of property, plant and equipment. 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 year ended December 31, 2010, the Company recognized additional impairments of $153.2 million with a corresponding reduction in property, plant and equipment for the Shallow Gas, Deep Gas and Non-core CGUs due to declines in the future price forecasts used by the Company's independent qualified reserves evaluators for natural gas prices.

Additional impairment charges were recognized at September 30, 2011 and December 31, 2011 as a result of changes in natural gas and natural gas liquids prices and the impact on the fair value of the Company's Shallow Gas, Deep Gas and Non-Core CGUs. In aggregate, the Company recognized $35.2 million of impairments during the year ended December 31, 2011 in the following CGUs: Shallow Gas $25.8 million, Deep Gas $2.6 million (net of impairment reversals of $9.7 million) and Non-Core $6.8 million. The forward price outlook for natural gas dropped significantly at December 31, 2011 compared to the outlook at September 30, 2011 which led to the recognition of impairment charges for the Shallow Gas, Deep Gas and Non-Core CGUs in the fourth quarter of 2011 as follows: $22.6 million, $12.3 million and $1.4 million respectively.

General and Administrative Expenses. For the year ended December 31, 2011, general and administrative expenses, excluding stock-based compensation were $9.4 million or $3.36 per BOE (December 31, 2010 – $8.4 million or $3.04 per BOE) and for the fourth quarter of 2011 were $2.2 million or $3.03 per BOE (December 31, 2010 – $2.4 million or $3.18 per BOE). Gross general and administrative expenses increased for the year ended December 31, 2011 over 2010 due to higher levels of employee compensation and higher audit fees related to the implementation of IFRS, whereas the lower costs in the fourth quarter of 2011 relative to 2010 is a reflection of the timing of recognition of year end compensation costs.

	Three months ended December 31		Year ended December 31	
(thousands of dollars)	*2011*	*2010*	*2011*	*2010*
General and administrative (gross)	$ 3,376	$ 4,082	$ 14,816	$ 13,742
Overhead recoveries	(490)	(570)	(1,802)	(1,751)
Capitalized	(674)	(1,106)	(3,569)	(3,594)
General and administrative (cash)	$ 2,212	$ 2,406	$ 9,445	$ 8,397
Net stock-based compensation	230	235	960	1,020
General and administrative (net)	$ 2,442	$ 2,641	$ 10,405	$ 9,417
General and administrative (cash) *($/BOE)*	$ 3.03	$ 3.18	$ 3.36	$ 3.04
% Capitalized	20%	27%	24%	26%

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

Stock-Based Compensation. The Company accounts for stock-based compensation plans using the fair value method of accounting. Stock-based compensation expense was $1.5 million in 2011 ($1.0 million net of amounts capitalized) versus $1.6 million ($1.0 million net of amounts capitalized) in 2010. Stock-based compensation costs were $0.3 million for the fourth quarter of 2011 ($0.2 million net of amounts capitalized) versus $0.4 million ($0.2 million net of amounts capitalized) in the fourth quarter of 2010.

Finance Expenses. Finance expenses were $3.4 million for the fourth quarter of 2011, compared to $3.3 million in the third quarter of 2011 and $1.5 million in the fourth quarter of 2010. Finance expenses were $11.9 million for the year ended December 31, 2011, compared to $5.0 million in the comparable period of 2010. The increase in finance expenses from 2010 is the result of higher interest and accretion on the $96 million (principal) of convertible debentures issued on December 31, 2010 and June 8, 2011 at 7.5% and 7.25% respectively. The average effective interest rate on outstanding bank loans was 5.3% for the year ended December 31, 2011 compared to 4.9% for the comparable period in 2010.

(thousands of dollars)	Three months ended December 31 2011	2010	Year ended December 31 2011	2010
Interest and accretion on convertible debentures	$ 2,234	$ 13	$ 7,065	$ 13
Interest expense on credit facilities and other	853	1,085	3,247	3,339
Accretion on decommissioning obligations	335	423	1,630	1,654
Finance expenses	$ 3,422	$ 1,521	$ 11,942	$ 5,006

Decommissioning obligations. In the fourth quarter of 2011, the Company recorded an increase in decommissioning obligations of $2.8 million. The increase is the result of additional decommissioning obligations relating to current drilling and new infrastructure construction in the fourth quarter of 2011. Accretion expense was $0.3 million for the fourth quarter of 2011 compared to $0.4 million in the third quarter of 2011 and $0.4 million in the fourth quarter of 2010 and was included in finance expenses.

The risk-free discount rates used by the Company to measure the obligations at December 31, 2011 were between 0.9% and 3.1% depending on the timelines to reclamation and decreased from the start of the year as a result of changes in the Canadian bond market.

Income Taxes. Anderson is not currently taxable and has the following estimated tax pool balances at December 31, 2011. Non-capital losses are estimated assuming certain discretionary claims related to tax pools are made in the current year. Tax pool classifications are estimates as some new wells have not yet had their status as exploratory or development confirmed.

Canadian Exploration Expenses (CEE)	$ 72 million
Canadian Development Expenses (CDE)	184 million
Undepreciated Capital Cost (UCC)	112 million
Canadian Oil and Gas Property Expenses (COGPE)	5 million
Non-Capital Losses	119 million
Share issue costs	5 million
Total	$ 497 million

Funds from Operations. Funds from operations increased by 49% to $54.5 million in 2011 compared to $36.5 million in 2010. On a per share basis, funds from operations were $0.32 per share in 2011 compared to $0.21 per share in 2010. For the three months ended December 31, 2011, funds from operations were $17.0 million or $0.10 per share, an increase of 34% over the previous quarter of $12.7 million or $0.07 per share, and an increase of 83% from the fourth quarter of 2010 of $9.3 million or $0.05 per share. Funds from operations increased as the Company refocused its capital initiatives on oil prospects, which are brought on production at significantly higher expected operating margins. In the fourth quarter of 2011, oil and NGLs accounted for $23.6 million or 72% of oil and gas sales compared to $17.9 million or 63% in the third quarter of 2011 and $11.5 million or 48% in the fourth quarter of 2010.

(thousands of dollars)	Three months ended December 31 2011	2010	Year ended December 31 2011	2010
Cash from operating activities	$ 16,462	$ 10,488	$ 54,309	$ 40,332
Changes in non-cash working capital	389	(1,324)	(94)	(5,365)
Decommisioning expenditures	146	118	249	1,549
Funds from operations	$ 16,997	$ 9,282	$ 54,464	$ 36,516

Earnings. The Company reported a $32.2 million loss in the fourth quarter of 2011 compared to earnings of $7.5 million in the third quarter of 2011 and a loss of $36.5 million in the fourth quarter of 2010. Earnings were lower in the fourth quarter of 2011 compared to the previous quarter as a result of higher depletion, impairments recognized on the Company's Shallow Gas, Deep Gas and Non-core CGUs and unrealized losses on the Company's derivative oil contracts recognized in the fourth quarter of 2011. The Company reported a loss of $22.4 million in 2011 compared to a loss of $124.8 million in 2010. As with funds from operations, earnings continue to be impacted by low natural gas prices. The change in the Company's focus to crude oil, with its currently higher operating margins, is expected to improve future earnings.

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

SENSITIVITIES

	Funds from Operations		*Earnings*	
	Millions	*Per Share*	*Millions*	*Per Share*
$0.50/Mcf in price of natural gas	$ 4.7	$ 0.03	$ 3.5	$ 0.02
US $5.00/bbl in the WTI crude price	$ 3.3	$ 0.02	$ 2.5	$ 0.01
US $0.01 in the US/Cdn exchange rate	$ 1.0	$ 0.01	$ 0.7	$ 0.00
1% in short-term interest rate	$ 0.6	$ 0.00	$ 0.4	$ 0.00

This sensitivity analysis was calculated by applying different pricing, interest rate and exchange rate assumptions to the 2011 actual results related to production, prices, royalty rates, operating costs and capital spending. As the contribution of oil production continues to increase as a percentage of total production, the impact of oil prices will be more significant and the impact of natural gas prices will be less significant to funds from operations and earnings than is shown in the table above.

CAPITAL EXPENDITURES

The Company spent $40.9 million in capital expenditures, net of dispositions and drilling incentive credits, in the fourth quarter of 2011 and $159.3 million for the year ended December 31, 2011. The breakdown of expenditures is shown below:

	Three months ended December 31		*Year ended December 31*	
(thousands of dollars)	*2011*	*2010*	*2011*	*2010*
Land, geological and geophysical costs	$ 642	$ 58	$ 4,609	$ 683
Acquisitions	66	298	66	1,736
Proceeds on disposition	(61)	(68)	(11,631)	(2,467)
Drilling, completion and recompletion	32,196	19,336	127,456	72,873
Drilling incentive credits	-	162	(400)	(3,455)
Facilities and well equipment	7,417	6,297	35,418	40,079
Capitalized G&A	674	1,106	3,569	3,594
Total finding, development & acquisition expenditures	40,934	27,189	159,087	113,043
Change in compressor and other equipment inventory	(24)	(957)	104	(1,601)
Office equipment and furniture	14	8	84	67
Total net cash capital expenditures	$ 40,924	$ 26,240	$ 159,275	$ 111,509

Drilling statistics are shown below:

	Three months ended December 31				*Year ended December 31*			
	2011		*2010*		*2011*		*2010*	
	Gross	*Net*	*Gross*	*Net*	*Gross*	*Net*	*Gross*	*Net*
Gas	-	-	-	-	-	-	23	19.0
Oil	10	9.6	6	5.1	51	43.8	22	16.3
Dry	1	1.0	-	-	1	1.0	4	2.8
Total	11	10.6	6	5.1	52	44.8	49	38.1
Success rate *(%)*	91%	91%	100%	100%	98%	98%	92%	93%

For the year ended December 31, 2011, the Company drilled 51 gross (44.7 net capital) Cardium horizontal wells. Of the total 52 gross wells drilled, the Company drilled 10 gross (9.6 net capital) successful Cardium horizontal wells and one 100% dry hole in the fourth quarter of 2011. The Company has not drilled any vertical Edmonton Sands shallow gas wells since the first quarter of 2010. Approximately $7.4 million was spent on facilities and well equipment during the fourth quarter of 2011. Actual capital expenditures net of dispositions in 2011 exceeded budget primarily due to the deferral of expected dispositions to 2012. In addition, the Company participated in one gross (0.5 net capital) well more than budgeted, accelerated certain Cardium facility expenditures and experienced some cost overruns on wells drilled near year end.

During 2011 the Company sold non-core, heavy oil and other assets for proceeds of $11.6 million, which represented approximately 83 BOPD (89 BOED). Subsequent to December 31, 2011, the Company sold or has entered into agreements to sell minor properties for $6.3 million in gross proceeds (subject to adjustments).

RESERVES

The Company's reserves were evaluated by GLJ Petroleum Consultants ("GLJ") in accordance with National Instrument 51-101 ("NI 51-101") as of December 31, 2011, prepared in accordance with procedures and standards contained in the Canadian Oil and Gas Evaluation ("COGE") Handbook. The reserves definitions used in preparing the report are those contained in the COGE Handbook and the Canadian Securities Administrators National Instrument 51-101 – *Standards of Disclosure for Oil and Gas Activities* ("NI 51-101"). The tables in this section are an excerpt from what will be contained in the Company's Annual Information Form for the year ended December 31, 2011 ("AIF") as the Company's NI 51-101 annual required filings.

At December 31, 2011, the Company's proved developed producing ("PDP"), total proved ("TP") and proved plus probable ("P&P") reserves were 12.6 MMBOE, 20.9 MMBOE and 34.3 MMBOE respectively.

Oil and NGL reserves now represent 33% of the Company's PDP, 29% of TP and 31% of the P&P reserves as compared to 23%, 19% and 21% respectively at December 31, 2010. The Company increased PDP, TP and P&P oil and NGL reserves by 53%, 57% and 63% in the past year.

SUMMARY OF GROSS OIL AND GAS RESERVES[(1)]

As at December 31, 2011

	Oil [(2)] (Mbbls)	*Natural Gas [(2)] (MMcf)*	*Natural Gas Liquids (Mbbls)*	*Total BOE (MBOE)*
Proved developed producing	2,576	50,783	1,534	12,573
Proved developed non-producing	41	6,532	22	1,151
Proved undeveloped	1,507	31,727	426	7,221
Total proved	4,124	89,042	1,982	20,945
Probable	3,320	52,347	1,335	13,379
Total proved plus probable	7,444	141,389	3,316	34,325

(1) Columns may not add due to rounding.
(2) Coal Bed Methane is not material to report separately and is included in the Natural Gas category. Heavy Oil is not material to report separately and is included in the Oil category.

NET PRESENT VALUE BEFORE INCOME TAXES[1]

As at December 31, 2011 - GLJ December 31, 2011 Price Forecast, Escalated Prices

(thousands of dollars)	*0%*	*5%*	*10%*	*15%*	*20%*
Proved developed producing	308,576	247,604	207,906	180,236	159,918
Proved developed non-producing	13,942	10,000	7,366	5,541	4,240
Proved undeveloped	78,161	40,082	17,806	4,082	(4,713)
Total proved	400,679	297,687	233,078	189,858	159,445
Probable	346,038	195,982	122,234	81,541	56,965
Total proved plus probable	746,717	493,669	355,311	271,399	216,410

(1) Columns may not add due to rounding.

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

SUMMARY OF PRICING AND INFLATION RATE ASSUMPTIONS

As at December 31, 2011 - GLJ Forecast Prices and Costs

	Oil		*Natural Gas*	*Edmonton Liquids Prices*				
Year	*WTI Cushing ($US/bbl)*	*Light, Sweet Crude Edmonton ($Cdn/bbl)*	*AECO Gas Price ($Cdn/MMBTU)*	*Propane ($Cdn/bbl)*	*Butane ($Cdn/bbl)*	*Pentanes Plus ($Cdn/bbl)*	*Inflation Rate %*	*Exchange rate (US$/Cdn)*
2012	97.00	97.96	3.49	58.78	76.41	107.76	2.0	0.98
2013	100.00	101.02	4.13	60.61	78.80	108.09	2.0	0.98
2014	100.00	101.02	4.59	60.61	78.80	105.06	2.0	0.98
2015	100.00	101.02	5.05	60.61	78.80	105.06	2.0	0.98
2016	100.00	101.02	5.51	60.61	78.80	105.06	2.0	0.98
2017	100.00	101.02	5.97	60.61	78.80	105.06	2.0	0.98
2018	101.35	102.40	6.21	61.44	79.87	106.49	2.0	0.98
2019	103.38	104.47	6.33	62.68	81.49	108.65	2.0	0.98
2020	105.45	106.58	6.46	63.95	83.13	110.84	2.0	0.98
2021	107.56	108.73	6.58	65.24	84.81	113.08	2.0	0.98
Thereafter 2%								

Total future development costs included in the reserves evaluation were $149.8 million for total proved reserves and $264.9 million for proved plus probable reserves. Further details related to future development costs, including assumptions regarding the timing of the expenditures, will be included in the Company's AIF for the 2011 fiscal year. Future development costs are associated with the reserves as disclosed in the GLJ report and do not necessarily represent the Company's current exploration and development budget.

CONTINUITY OF GROSS RESERVES (1)

	Natural Gas (Bcf)			Oil and Natural Gas Liquids (Mbbls)		
	Proved	*Probable*	*Total*	*Proved*	*Probable*	*Total*
Opening balance December 31, 2010	97.3	53.3	150.6	3,899	2,685	6,584
Extensions and improved recovery	9.3	9.0	18.2	3,150	2,336	5,485
Technical revisions	4.6	0.2	4.8	137	(226)	(89)
Economic factors	(9.7)	(9.8)	(19.5)	-	-	-
Dispositions	(0.8)	(0.4)	(1.2)	(196)	(140)	(336)
Production	(11.5)	-	(11.5)	(884)	-	(884)
Closing balance December 31, 2011(2)	89.0	52.3	141.4	6,106	4,655	10,760

(1) Columns and rows may not add due to rounding.

(2) The closing balance for natural gas includes 2.7 Bcf of proved and 2.4 Bcf of probable Coal Bed Methane reserves. The closing balance for oil and natural gas liquids includes 35 Mbbls of proved and 36 Mbbls of probable Heavy Oil reserves.

The Company's reserves life indices are 7.5 years total proved and 12.2 years proved plus probable, based on 2011 annual production. With an average $0.97 per MMBTU reduction in GLJ's natural gas price outlook in the years 2012 to 2020, the Company experienced a negative revision for economic factors of 1.6 MMBOE for total proved and 3.3 MMBOE for proved plus probable reserves. The economic factors negative revision was almost entirely related to the Company's undeveloped gas reserves in the Edmonton Sands and CBM properties. Offsetting the economic factors were positive technical revisions of 0.9 MMBOE total proved and 0.7 MMBOE proved plus probable reserves. The Company experienced positive proved developed producing technical revisions of 0.3 MMBOE in the Edmonton Sands, indicative of improved performance. Reserves additions before revisions were 4.7 MMBOE total proved and 8.5 MMBOE proved plus probable, predominantly from Cardium oil horizontal drilling. The Company replaced 310% of its production with new proved plus probable reserves additions in 2011. The Company replaced 572% of its 2011 oil and NGL production with new P&P oil and NGL reserves.

FINDING, DEVELOPMENT AND ACQUISITION COSTS

Year Ended December 31, 2011

(in thousands of dollars)	*Proved*	*Proved plus Probable*
Finding, development & acquisition expenditures	$ 159,087	$ 159,087
Change in future development costs	12,797	25,015
	$ 171,884	$ 184,102
Adjustment to change in future development costs for natural gas economic factors	23,400	44,405
	$ 195,284	$ 228,507
Reserve additions *(MBOE)*	4,692	8,526
Dispositions *(MBOE)*	(337)	(537)
Technical revisions *(MBOE)*	901	714
	5,256	8,703
2011 finding, development & acquisition costs – additions and technical revisions, including change in future development costs, excluding economic factors and the change in future development costs related to economic factors *($/BOE)*	$ 37.15	$ 26.26

The Company experienced a significant revision for economic factors in 2011 which not only reduced reserves but also reduced future development capital. To measure FD&A costs excluding the impact of economic factors, the future development capital was also adjusted upwards to exclude the effect of removing these reserves. FD&A costs including future development costs for additions and technical revisions, but excluding economic factors were $37.15 per BOE total proved and $26.26 per BOE for proved plus probable. Economic factors are influenced by consultant price forecasts and changes in natural gas price forecasts may cause economic factors to be positive in future years. Calculated on a similar basis, the Company's FD&A costs in 2010 were $22.30 per BOE on a proved basis and $22.35 per BOE on a proved plus probable basis and FD&A costs in 2009 were $8.64 per BOE on a proved basis and $8.46 per BOE on a proved plus probable basis. The three year average FD&A costs was $24.78 per BOE total proved and $20.32 per BOE total proved plus probable. The aggregate of the exploration, development and acquisition costs incurred in the most recent financial year and the change during the year in estimated future development costs generally will not reflect total finding, development and acquisition costs related to reserves additions for that year.

SHARE INFORMATION

The Company's shares have been listed on the Toronto Stock Exchange since September 7, 2005 under the symbol "AXL". As of March 16, 2012, there were 172.5 million common shares outstanding, 13.9 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 2011, 64,400 common shares (2010 – 84,900) were issued under the employee stock option plan.

SHARE PRICE ON TSX

		2011		*2010*
High	$	1.36	$	1.57
Low	$	0.35	$	0.95
Close	$	0.54	$	1.05
Volume		141,911,562		120,489,236
Shares outstanding at December 31		172,549,701		172,485,301
Market capitalization at December 31	$	93,176,839	$	181,109,566

The statistics above include trading on the Toronto Stock Exchange only. Shares also trade on alternative platforms like Alpha, Chi-X, Pure and Omega. Approximately 99.7 million common shares traded on these alternative exchanges in 2011 (2010 – 65.0 million). Including these exchanges, an average of 966,254 common shares traded per day in 2011 (2010 – 736,212), representing a turnover ratio of 140% (2010 – 109%).

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

RELATED PARTY TRANSACTIONS

On 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.

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 $31.8 million bought deal offering of common shares.

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 the Company's performance under IFRS reporting 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 December 31, 2011, the Company had outstanding bank loans of $88.7 million, convertible debentures of $96.0 million (principal) and a cash working capital deficiency (excludes unrealized gain on derivative contracts) of $44.0 million. The working capital deficiency is largely due to accruals associated with the capital program in the last quarter of the year and will be funded through the available credit facilities, future operating cash flows and minor property sales. The following table shows the changes in bank loans plus cash working capital deficiency:

	Three months ended December 31		*Year ended December 31*	
(thousands of dollars)	*2011*	*2010*	*2011*	*2010*
Bank loans plus cash working capital deficiency, beginning of period	$ (108,583)	$ (102,198)	$ (71,507)	$ (72,524)
Funds from operations	16,997	9,282	54,464	36,516
Net cash capital expenditures	(40,924)	(26,240)	(159,275)	(111,509)
Proceeds from issue of convertible debentures, net of issue costs	-	47,700	43,860	47,700
Proceeds from issue of share capital, net of issue costs	-	-	-	29,792
Proceeds from exercise of stock options	-	67	51	67
Decommissioning expenditures	(146)	(118)	(249)	(1,549)
Bank loans plus cash working capital deficiency, end of period	$ (132,656)	$ (71,507)	$ (132,656)	$ (71,507)

The Company is committed to drill 74 gross (53.5 net capital) Edmonton Sands gas wells under its farm-in agreement by March 31, 2013. The Company does not plan to drill any additional Edmonton Sands gas wells until the first quarter of 2013.

The Company's need for capital will be both short-term and long-term in nature. Short-term capital is required to finance accounts receivable and other similar short-term assets while the acquisition and development of oil and natural gas properties requires larger amounts of long-term capital. At December 31, 2011, the Company had total credit facilities of $135 million, consisting of a $110 million extendible revolving term credit facility, a $10 million working capital credit facility and a $15 million supplemental credit facility with a syndicate of Canadian banks. The Company had $46.2 million of credit available at December 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. The net proceeds were initially used to pay down bank debt. The availability created in the credit facilities, along with cash flows, was used to finance the Company's capital programs. Anderson will prudently use its bank loan facilities to finance its operations as required. Capital spending for the first half of 2012 is expected to be approximately $12.0 million net of proceeds on dispositions of approximately $6.3 million and will be funded by cash flow from operations.

Remaining cash flow will be used to pay down bank debt. The available lending limits under the bank facilities are reviewed twice a year and are based on the bank syndicate's interpretation of the Company's reserves and future commodity prices. The last review was conducted in November 2011. There can be no assurance that the amount of the available bank lines will not be adjusted at the next scheduled review to be completed prior to July 11, 2012. The Company plans to fund its 2012 capital program from a combination of cash flow, existing credit facilities and asset dispositions. Oil and natural gas prices will impact the level of capital spending in 2012.

OFF BALANCE SHEET ARRANGEMENTS

The Company had no guarantees or off-balance sheet arrangements other than as described below under "Contractual Obligations".

CONTRACTUAL OBLIGATIONS

The Company enters into various contractual obligations in the course of conducting its operations. At December 31, 2011, 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 December 31, 2011.
- *Letters of credit* – Letters of credit of approximately $0.1 million had been issued in the normal course of business as at December 31, 2011 (December 31, 2010 – $0.1 million).
- *Convertible debentures* – The Company has $96.0 million (principal) in convertible debentures outstanding at December 31, 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"). Each convertible debenture has 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 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.
- *Firm service transportation commitments* – The Company has entered into firm service transportation agreements for approximately 19 million cubic feet per day of gas sales for various terms expiring between 2012 and 2020.
- *Cardium Horizontal Well Program (Oil)* – The Company has farm-in obligations to drill six gross (4.5 net capital) horizontal wells in the Cardium geological formation prior to dates ranging from August 1, 2012 to September 30, 2012. One agreement has a $100,000 non-performance fee clause should the Company fail to drill the well. Another agreement pertains to two wells; there is a $100,000 non-performance fee should the Company fail to drill both wells, and if only one well is drilled, the Company would also forfeit fifty per cent of the interest in the first well drilled under the agreement.

- *Edmonton Sands Well Program (Natural Gas)* – In 2009, the Company committed to a 200 well drilling and completion program in the Edmonton Sands geological formation (the "Program") under a farm-in agreement with a large international oil and gas company (the "Farmor") from which the Company will earn an interest in up to 120 sections of land. The Company is obligated to complete the Program or before March 31, 2013 and has an option to continue the farm-in transaction until March 1, 2014 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 Company and the Farmor can then jointly develop the lands on denser drilling spacing under terms of an operating agreement. As of December 31, 2011, the Company had drilled 126 wells under the farm-in agreement and deferred the drilling of the remaining 74 gross (53.5 net capital) wells until 2013 due to depressed natural gas prices. A $550,000 penalty is payable for each well not drilled under the commitment as of March 31, 2013, 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 approximately $10 million.

As at December 31, 2011, the Company had the following minimum contractual obligations including long-term debt:

Contractual obligations	Payments due by year *(in thousands of dollars)*					
	2012	*2013*	*2014*	*2015*	*2016*	*Thereafter*
Accounts payable[3]	$ 60,573	$	$	$	$	$
Bank loans[1]	-	88,682	-	-	-	-
Convertible debentures[2][3]	5,523	7,085	7,085	7,085	55,210	47,667
Non-cancellable operating leases	1,952	332	135	-	-	-
Crude oil transportation contract	257	257	257	257	257	1,291
Gas gathering contract	244	244	244	244	244	467
Other capital commitments	505	-	-	-	-	-
Farm-in commitments	200	10,000	-	-	-	-
Firm service	1,255	871	679	608	95	299
Total	$ 70,509	$ 107,471	$ 8,400	$ 8,194	$ 55,806	$ 49,724

(1) Assumes the credit facilities are not renewed on July 11, 2012.
(2) Includes the associated interest payments.
(3) Accounts payable and accruals includes $3.4 million of interest relating to convertible debentures. The total cash interest payable in 2012 on the convertible debentures is $9.0 million.

These obligations are described further in note 21 to the consolidated financial statements for the years ended December 31, 2011 and 2010.

CRITICAL ACCOUNTING ESTIMATES

The Company's significant accounting policies are disclosed in note 3 to the consolidated financial statements. Certain accounting policies require that management make appropriate decisions with respect to the formulation of estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses. These accounting policies are discussed below and are included to aid the reader in assessing the critical accounting policies and practices of the Company and the likelihood of materially different results than reported. The Company's management reviews its estimates regularly. The emergence of new information and changed circumstances may result in actual results that differ materially from current estimates.

Oil and Gas Reserves. Proved and probable reserves, as defined by the Canadian Securities Administrators in NI 51-101 with reference to the Canadian Oil and Gas Evaluation Handbook, are estimated using independent reserves evaluator reports and represent the estimated quantities of crude oil, natural gas and natural gas liquids which geological, geophysical and engineering data demonstrate with a specified degree of certainty to be recoverable in future years from known reservoirs and which are considered commercially producible. There should be a 50 percent statistical probability that the actual quantity of recoverable reserves will be more than the amount estimated as proved and probable and a 50 percent statistical probability that it will be less. The equivalent statistical probabilities for the proved component of proved and probable reserves are 90 percent and 10 percent, respectively. Determination of reserves is a complex process involving judgments, estimates and decisions based on available geological, engineering, production and any other relevant data. These estimates are subject to material change as economic conditions change and ongoing production and development activities provide new information.

Purchase price allocations, depletion and depreciation and amounts used in impairment calculations are based on estimates of oil and gas reserves. Reserves estimates are based on engineering data, estimated future prices, expected future rates of production and timing of future capital expenditures. By their nature, these estimates are subject to measurement uncertainties and interpretations and the impact on the financial statements could be material. The Company expects that over time, its reserves estimates will be revised upward or downward based on updated information such as the results of future drilling, testing and production levels and may be affected by changes in commodity prices.

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

Income Taxes. The determination of the Company's income and other tax liabilities requires interpretation of complex laws and regulations often involving multiple jurisdictions. All tax filings are subject to audit and potential reassessment after the lapse of considerable time. Accordingly, the actual income tax liability may differ from that estimated and recorded by management. The Company estimates its future income tax rate in calculating its future income tax liability. Various assumptions are made in assessing when temporary differences will reverse and this will impact the rate used.

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

ADOPTION OF IFRS

International Financial Reporting Standards. The Company adopted IFRS effective January 1, 2011. As a result, the Company's financial results for the year ended December 31, 2011 and comparative periods are reported under IFRS while selected historical data before 2010 continues to be reported under CGAAP. Refer to note 23 of the consolidated financial statements for the years ended December 31, 2011 and 2010 for complete disclosure of the Company's assessment of the impacts of the transition to IFRS.

Summary of impact to the Company's business and cash flows under IFRS. The reconciling items discussed below between CGAAP and IFRS policies have had no material impact on the Company's strategic decisions, business practices or prospects, operations, key agreements including debt agreements and covenants, or cash flow from operations before changes in non-cash working capital. However, there has been a significant impact on individual components of the consolidated statement of financial position (formerly known as the "balance sheet"), shareholders' equity, and on earnings (loss), as well as substantially changing the form and content of certain disclosures.

The Company restated its statement of financial position using IFRS and reconciled the significant changes from the amounts previously reported under CGAAP.

The following provides summary reconciliations of Anderson's January 1, 2010 CGAAP to IFRS transitional statement of financial position and December 31, 2010 statement of financial position as well as an earnings reconciliation for the year ended December 31, 2010 and a discussion of the significant IFRS accounting policy changes:

Summarized statement of financial position at January 1, 2010:

(in thousands of dollars)	*CGAAP*	*Effect of Transition to IFRS*	*IFRS*
ASSETS			
Current assets	$ 26,769	$ -	$ 26,769
Property, plant and equipment *(notes a and b)*	470,400	(67,193)	403,207
	$ 497,169	$ (67,193)	$ 429,976
LIABILITIES AND EQUITY			
Current liabilities	$ 36,889	$ -	$ 36,889
Bank loans	62,404	-	62,404
Decommissioning obligations *(note d)*	33,879	13,778	47,657
Deferred tax liability *(note h)*	31,278	(20,358)	10,920
Share capital *(notes f and h)*	391,637	4,887	396,524
Contributed surplus *(note e)*	6,104	234	6,338
Deficit *(note i)*	(65,022)	(65,734)	(130,756)
	$ 497,169	$ (67,193)	$ 429,976

Summarized statement of financial position at December 31, 2010:

(in thousands of dollars)	*CGAAP*	*Effect of Transition to IFRS*	*IFRS*
ASSETS			
Current assets	$ 28,582	$ (508)	$ 28,074
Property, plant and equipment *(notes a and b)*	506,533	(185,860)	320,673
	$ 535,115	$ (186,368)	$ 348,747
LIABILITIES AND EQUITY			
Current liabilities	$ 48,780	$ -	$ 48,780
Bank loans	52,719	-	52,719
Convertible debentures	43,460	-	43,460
Decommissioning obligations *(note d)*	36,320	15,230	51,550
Deferred tax liability *(note h)*	20,045	(49,702)	(29,657)
Share capital *(notes f and h)*	422,038	4,887	426,925
Equity component of convertible debentures *(note g)*	4,242	(1,650)	2,592
Contributed surplus *(note e)*	8,164	(243)	7,921
Deficit *(note i)*	(100,653)	(154,890)	(255,543)
	$ 535,115	$ (186,368)	$ 348,747

Summarized net earnings reconciliations for 2010:

(in thousands of dollars)	*YTD 2010*	*Q4 2010*	*Q3 2010*	*Q2 2010*	*Q1 2010*
Loss under CGAAP	$ (35,631)	$ (11,741)	$ (9,046)	$ (8,891)	$ (5,953)
Increase (decrease) in earnings under IFRS:					
General and administrative *(note c)*	(664)	(233)	(150)	(81)	(200)
Stock-based payments *(note e)*	155	(1)	102	23	31
Depletion and depreciation *(note c)*	33,071	9,028	8,306	8,392	7,345
Accretion on decommissioning obligations *(note d)*	888	230	228	219	211
Gain on sale of property, plant and equipment *(note c)*	389	69	(388)	35	673
Impairment of property, plant and equipment *(note b)*	(153,165)	(42,196)	(48,317)	(3,112)	(59,540)
Deferred tax *(note h)*	30,170	8,299	10,236	(1,354)	12,989
Impact of IFRS	(89,156)	(24,804)	(29,983)	4,122	(38,491)
Loss under IFRS	$ (124,787)	$ (36,545)	$ (39,029)	$ (4,769)	$ (44,444)

Notes to reconciliations:
(a) *IFRS 1 Exemptions*:

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.

Business Combinations. The Company applied the IFRS 1 exemption and did not retrospectively revalue business combinations that occurred before January 1, 2010 in accordance with IFRS 3, Business Combinations. Accordingly, there were no adjustments made to the Company's January 1, 2010 financial statements as a result of this exemption.

Borrowing Costs. The Company applied the IFRS 1 exemption which allowed first-time adopters to use the transitional provisions set out in IAS 23, Borrowing Costs and set the effective date of the standard as January 1, 2010, which is the date of the Company's transition to IFRS. Accordingly, there were no adjustments made to the Company's January 1, 2010 financial statements as a result of this exemption.

Refer to notes (d) and (e) below for further discussion on IFRS 1 exemptions taken for decommissioning obligations and share-based payments.

(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 the recoverable amount (greater of value in use or fair value less costs to sell) compared with the asset's carrying amount to 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 was based on undiscounted cash flows using asset groupings with both independent cash inflows and cash outflows.

As a result of applying the deemed cost exemption at January 1, 2010, the Company recorded an impairment of $67.2 million with a corresponding reduction in property, plant and equipment. For the year ended December 31, 2010, the Company recognized additional impairments of $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 unit of production over proved reserves. 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.

At January 1, 2010, there were no amounts recorded as a result of the policy differences as discussed above. For the year ended December 31, 2010, the use of proved plus probable reserves in conjunction with lower net book values due to impairments in the Company's Shallow Gas, Deep Gas and Non-core CGUs resulted in a decrease to depletion and depreciation of $33.1 million with a corresponding increase to property, plant and equipment.

Other adjustments. IFRS requires that gains or losses be reported on the disposition of property, plant and equipment. Under Canadian GAAP, gains or losses on disposition of property, plant and equipment were only reported when the disposition resulted in more than a 20 percent change in the depletion rate. As a result of this requirement, the Company reported a gain of $0.4 million during the year ended December 31, 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 expense by $0.7 million during the year ended December 31, 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 $0.3 million at December 31, 2010 with a corresponding decrease to the deferred tax liability.

(d) IAS 37 Adjustments – Provisions, Contingent Liabilities and Contingent Assets. Consistent with IFRS, decommissioning obligations (asset retirement obligations under Canadian GAAP) were measured under Canadian GAAP based on the estimated cost of decommissioning, discounted to their net present value upon initial recognition. Under Canadian GAAP, asset retirement obligations were discounted at a credit adjusted risk fee rate of eight to 10 percent. Under IFRS, decommissioning obligations are discounted at a risk free rate of one to four percent depending upon the estimated timelines to reclamation. Under IFRS, decommissioning obligations are also required to be re-measured at each reporting period to incorporate changes in future cash flow estimates, timelines to reclamation as well as discount rates used in present valuing the obligations.

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 December 31, 2010, the Company increased its decommissioning obligations by $15.1 million from Canadian GAAP. The Company also increased the value of its plant, property and equipment for December 31, 2010 by $2.2 million for new obligations incurred during 2010.

For the year ended December 31, 2011, accretion expense decreased by $0.9 million under IFRS compared to Canadian GAAP as a result of higher initial decommissioning obligations being recognized under IFRS and lower discount rates being used. Under IFRS, accretion on decommissioning obligations is included in finance expenses as opposed to Canadian GAAP where these amounts were included in depletion, depreciation and accretion.

(e) IFRS 2 Adjustments – Share-based Payments. Under Canadian GAAP, the Company recognized stock-based compensation expense on a straight-line basis through the date of full vesting and incorporated a forfeiture rate, 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 estimating a forfeiture rate is no longer optional.

The Company applied the IFRS 1 exemption for equity instruments which vested before the transition date and did not retroactively restate them. All unvested options at transition date were retroactively restated in accordance with IFRS 2 with the adjustment going through opening retained earnings. As a result, the Company recorded an additional $0.2 million in contributed surplus at January 1, 2010 for unvested options with the offset going to opening retained earnings.

For the year ended December 31, 2010, the Company reduced contributed surplus by $0.5 million and reduced the amount of stock-based compensation capitalized by $0.3 million for a net reduction in stock-based compensation expense of $0.2 million. Under Canadian GAAP, stock-based compensation expense was disclosed separately on the consolidated statement of operations and comprehensive loss. Under IFRS, stock-based compensation expense 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 January 1, 2010, the Company recorded an additional $5.3 million to share capital with a corresponding reduction in retained earnings for flow through shares that had been previously issued and fully renounced at transition.

(g) Convertible Debentures. Under Canadian GAAP, the Company did not record a deferred tax difference on its convertible debentures. Under IFRS, the Company is required to record the deferred tax difference between the fair value of the liability component of the convertible debentures and the tax value of the convertible debentures with the difference being booked against the equity component of convertible debentures. As a result, the Company recorded $1.7 million in deferred tax against the equity component of convertible debentures at 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:

		December 31, 2010		*January 1, 2010*
Impairment of plant, property and equipment *(note b)*	$	(55,407)	$	(16,914)
Depletion and depreciation *(note c)*		8,268		-
Decommissioning obligation *(note d)*		(3,222)		(3,444)
Convertible debentures *(note g)*		1,650		-
Other adjustments *(note c)*		(483)		-
Decrease in deferred tax liability	$	(49,194)	$	(20,358)

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

Under Canadian GAAP, the Company was required to disclose future income taxes in the same current or long-term classification from which the timing differences arose. As such at December 31, 2010, the Company reported $0.5 million as a current asset related to timing differences that would reverse in one year. There is no such requirement under IFRS, therefore the Company removed the separate disclosure of current deferred taxes.

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

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

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

(j) Adjustments to the Company's Statements of Cash Flows 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 $0.7 million to operating cash flows, with and equal and opposite effect on investing cash flows for the year ended December 31, 2010.

NEW AND PENDING ACCOUNTING STANDARDS

The IASB has issued the following new standards and amendments, all of which are effective for annual periods beginning on or after January 1, 2013. Although early adoption is permitted, the Company has not done so as of December 31, 2011.

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

IAS 12 – Income Taxes. IAS 12 "Income Taxes" was amended on December 20, 2010 to remove subjectivity in determining on which basis an entity measures the deferred tax relating to an asset. The amendment introduces a presumption that an entity will assess whether the carrying value of an asset will be recovered through the sale of the asset. The amendment to IAS 12 is effective for reporting periods beginning on or after January 1, 2012. The implementation of the issued standard is not expected to have a significant impact on the Company's financial position or results.

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

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 at the financial year end of the Company, 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 ICOFR have been designed to provide reasonable assurance that all assets are safeguarded, transactions are appropriately authorized and to facilitate the preparation of relevant, reliable and timely information. The CEO and CFO have evaluated and tested the design and operating effectiveness of Anderson's ICOFR as of December 31, 2011 and have concluded that, these internal controls are designed properly and are effective in the preparation of financial statements for external purposes in accordance with IFRS. The CEO and CFO are required to cause the Company to disclose any change in the Company's ICOFR that occurred during the period beginning on October 1, 2011 and ending on December 31, 2011 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 continue to remain volatile as they are a geopolitical commodity, affected by concerns about economic markets in the U.S. and Europe and continued instability in oil producing countries. Differentials between WTI oil prices and prices received in Alberta have widened and also remain volatile. 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 most recent Annual Information Form 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 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 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.

Internationally, Canada is a signatory to the United Nations Framework Convention on Climate Change and previously ratified the Kyoto Protocol established thereunder, which set legally binding targets to reduce nation-wide emissions of carbon dioxide, methane, nitrous oxide, and other greenhouse gases ("GHGs"). The first commitment period under the Kyoto Protocol is the five year period from 2008 to 2012. In December 2011, the Canadian federal government announced that it would not agree to a second commitment period under the Kyoto Protocol after 2012. Domestically, the Canadian federal government released in 2007 its Regulatory Framework for Air Emissions, which was updated in March 2008 in a document entitled "Turning the Corner: Regulatory Framework for Industrial Greenhouse Emissions". Canada's previous GHG emission reduction target was 20% from 2006 levels by 2020, but on January 30, 2010 the Canadian federal government announced a new GHG emission reduction target consistent with the Copenhagen Accord to reduce GHG emissions to 17% below 2005 levels by 2020. Canada's framework proposes mandatory emissions intensity reduction obligations on a sector-by-sector basis. It is uncertain whether or when either Canadian federal GHG regulations for the oil and gas industry will be implemented, or what obligations might be imposed under any such systems. As the details of the implementation of any federal legislation for GHGs that is applicable to the oil and gas industry have not been announced, the effect on Anderson's operations cannot be determined at this time.

Additionally, regulation can take place at the provincial and municipal level. For example, Alberta introduced the Climate Change and Emissions Management Act, which provides a framework for managing GHG emissions and establishes a target of reducing specified gas emissions relative to gross domestic product to an amount that is equal to or less than 50% of 1990 levels by December 31, 2020. The accompanying regulations, the Specified Gas Emitters Regulation and the Specified Gas Emitters Reporting Regulation require mandatory emissions reductions through the use of emissions intensity targets and impose duties to report. The Canadian federal government proposes to enter into equivalency agreements with provinces that establish a regulatory regime to ensure consistency with the federal plan, but the success of any such plan is doubtful in the current political climate, leaving multiple overlapping levels of regulation.

The Government of Alberta implemented a new oil and gas royalty framework effective January 2009. The new framework establishes new royalties for conventional oil, natural gas and bitumen that are linked to price and production levels and apply to both new and existing conventional oil and gas activities and oil sands projects. Under the framework, the formula for conventional oil and natural gas royalties uses a sliding rate formula, dependent on the market price and production volumes. On March 3, 2009, June 11, 2009 and June 25, 2009, the Government of Alberta announced amendments to the framework. This incentive program included 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 was used to offset up to 50% of Crown royalties paid 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 adjustments to the royalty rates which became effective January 1, 2011. This adjustment included 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.

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 131 gross (81 net) sections in the Cardium fairway and has identified an inventory of 260 gross (166 net revenue) drill-ready Cardium horizontal oil locations, of which 75 gross (56 net revenue) have been drilled to March 16, 2012. 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.

STRATEGY

The Company is focused on converting its asset base to be more than 50% oil and NGL production. Proceeds from disposition of minor properties are being dedicated to reduce bank debt. Crude oil pricing remains strong, but volatile and Anderson has increased its hedge position to help protect its capital program and its shareholders from volatile oil markets. The Company will revisit its 2012 capital budget after spring breakup.

The Company is in the process of reviewing the contributions of its natural gas assets to the Company's cash flows in the current low price environment. In response to low natural gas prices, the Company plans to shut-in approximately 500 Mcfd of production from natural gas properties with higher operating costs. In a higher price environment, these natural gas wells could easily be returned to production.

Anderson has substantially grown its Cardium drilling inventory in the last three months and with the completion of the infrastructure projects, newly drilled Cardium horizontal wells can be easily connected to these gathering systems. Unlike natural gas markets, oil prices continue to remain strong and the economics of the Cardium oil drilling programs are excellent.

STRATEGIC ALTERNATIVES

The Board of Directors initiated a process to identify, examine and consider a range of strategic alternatives available to the Company with a view to enhancing shareholder value. The strategic alternatives considered may include, but are not limited to, a sale of all or a material portion of the assets of Anderson, either in one transaction or in a series of transactions, the outright sale of the Company, or a merger or other strategic transaction involving Anderson and a third party. The Board of Directors believes that the Company's shares trade at a significant discount to the value of the underlying assets, especially given its high quality Cardium oil production base, prospective Cardium horizontal oil drilling inventory and significant tax pools. The Board of Directors has established a special committee comprised of independent directors of the Company to oversee this process and has retained financial advisors to assist the Special Committee and the Board of Directors with the process. This process has not been initiated as a result of any particular offer.

It is Anderson's current intention to not disclose developments with respect to its strategic alternatives process unless and until the Board of Directors has approved a specific transaction or otherwise determines that disclosure is necessary in accordance with applicable law. The Company cautions that there are no assurances or guarantees that the process will result in a transaction or, if a transaction is undertaken, the terms or timing of such a transaction. The Company has not set a definitive schedule to complete its evaluation.

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 those quarters. In 2010, the Company changed its focus to oil projects in light of the continued depressed natural gas market, and suspended its shallow gas drilling program until natural gas prices improve. Revenues, funds from operations and earnings (loss) over the past year reflect the benefits from increased sales of crude oil volumes. Also, earnings were affected in each of the four quarters in 2010 by impairments in the value of property, plant and equipment related to natural gas reserves values. With continued volatility in commodity prices, Anderson's earnings were impacted by impairment reversals in the third quarter of 2011 and impairments in the fourth quarter of 2011.

SELECTED QUARTERLY INFORMATION

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

	Q4 2011	Q3 2011	Q2 2011	Q1 2011
Revenue, net of royalties	$ 28,457	$ 24,970	$ 27,776	$ 23,283
Funds from operations	$ 16,997	$ 12,655	$ 13,944	$ 10,868
Funds from operations per share, basic and diluted	$ 0.10	$ 0.07	$ 0.08	$ 0.06
Earnings (loss) before effect of impairments or reversals thereof	$ (4,939)	$ 6,667	$ 5,932	$ (3,681)
Earnings (loss) per share before effect of impairments or reversals thereof				
Basic and diluted	$ (0.03)	$ 0.04	$ 0.03	$ (0.02)
Earnings (loss)	$ (32,167)	$ 7,472	$ 5,932	$ (3,681)
Basic and diluted	$ (0.19)	$ 0.04	$ 0.03	$ (0.02)
Capital expenditures, including acquisitions net of proceeds on dispositions	$ 40,924	$ 49,713	$ 26,284	$ 42,354
Cash from operating activities	$ 16,462	$ 11,893	$ 14,953	$ 11,001
Daily sales				
Natural gas *(Mcfd)*	30,576	30,038	31,990	33,931
Oil *(bpd)*	2,122	1,709	1,759	1,372
NGL *(bpd)*	715	636	667	699
BOE *(BOED)*	7,933	7,351	7,758	7,726
Average prices				
Natural gas *($/Mcf)*	$ 3.20	$ 3.85	$ 3.79	$ 3.58
Oil *($/bbl)*	$ 96.33	$ 89.05	$ 99.39	$ 84.71
NGL *($/bbl)*	$ 72.71	$ 66.07	$ 74.24	$ 65.97
BOE *($/BOE)* (1)(2)	$ 44.70	$ 42.16	$ 44.71	$ 36.80

	Q4 2010	Q3 2010	Q2 2010	Q1 2010
Revenue, net of royalties	$ 21,690	$ 17,263	$ 18,622	$ 19,871
Funds from operations	$ 9,282	$ 7,876	$ 8,923	$ 10,435
Funds from operations per share, basic and diluted	$ 0.05	$ 0.05	$ 0.05	$ 0.06
Earnings (loss) before effect of impairment	$ (4,864)	$ (3,057)	$ (2,450)	$ 256
Earnings (loss) per share before effect of impairment				
Basic and diluted	$ (0.03)	$ (0.02)	$ (0.01)	$ -
Loss	$ (36,545)	$ (39,029)	$ (4,769)	$ (44,444)
Loss per share, basic and diluted	$ (0.21)	$ (0.23)	$ (0.03)	$ (0.27)
Capital expenditures, including acquisitions net of dispositions	$ 26,240	$ 39,378	$ 12,664	$ 33,227
Cash from operating activities	$ 10,488	$ 8,287	$ 8,811	$ 12,746
Daily sales				
Natural gas *(Mcfd)*	38,479	35,778	38,998	35,221
Oil *(bpd)*	992	568	491	345
NGL *(bpd)*	823	761	741	785
BOE *(BOED)*	8,228	7,292	7,732	7,000
Average prices				
Natural gas *($/Mcf)*	$ 3.48	$ 3.43	$ 3.78	$ 5.22
Oil *($/bbl)*	$ 77.62	$ 68.24	$ 70.45	$ 75.47
NGL *($/bbl)*	$ 58.87	$ 51.41	$ 53.55	$ 56.68
BOE *($/BOE)* (1)(2)	$ 31.63	$ 28.21	$ 28.88	$ 36.93

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

(2) Excludes realized and unrealized gains (losses) on derivative contracts as follows: Q4 2011 – ($0.3) million and ($7.9) million respectively; Q3 2011 – $0.9 million and $6.4 million respectively; Q2 2011 – ($0.8) million and $7.7 million respectively; Q1 2011 – ($0.4) million and ($2.8) million respectively; and Q4 2010 – ($0.1) million and ($1.9) million respectively.

SELECTED ANNUAL INFORMATION

YEARS ENDED DECEMBER 31
(in thousands, except per share amounts)

		IFRS 2011		IFRS 2010		CGAAP 2009
Total oil and gas sales[(1)]	$	118,292	$	86,457	$	76,993
Total revenue, net of royalties[(1)]	$	104,486	$	77,446	$	68,740
Earnings (loss) before effect of impairment	$	3,979	$	(10,115)	$	(36,458)
Earnings (loss) before effect of impairment per share						
Basic	$	0.02	$	(0.06)	$	(0.29)
Diluted	$	0.02	$	(0.06)	$	(0.29)
Loss	$	(22,444)	$	(124,787)	$	(36,458)
Loss per share						
Basic	$	(0.13)	$	(0.73)	$	(0.29)
Diluted	$	(0.13)	$	(0.73)	$	(0.29)
Total assets	$	460,319	$	378,404	$	497,169
Total bank loans	$	88,682	$	52,719	$	62,404
Total convertible debentures, liability component	$	84,796	$	43,460	$	-

(1) Includes royalty and other income classified with oil and gas sales. Excludes the realized loss and unrealized gain on derivative contracts in 2011 of ($0.6) million and $3.3 million (2010 – ($0.1) million realized loss and ($1.9) million unrealized loss).

Total oil and gas sales and total revenue, net of royalties have grown year over year as shown above due to the focus on increasing oil production, as well as increased oil prices. However, loss and loss per share have increased due to impairment charges. These impairment charges have also reduced total assets.

Long-term debt including convertible debentures has grown since 2009 reflecting the financing related to the capital programs to develop oil properties.

ADDITIONAL INFORMATION

Additional information regarding Anderson and its business and operation, including its most recently filed annual information form is available on the Company's profile on SEDAR at www.sedar.com. This information is also available on the Company's website at www.andersonenergy.ca.

Forward-Looking Statements

Certain statements in this financial report 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; estimates of future revenues, costs, netbacks, funds from operations and debt levels; potential results of the strategic alternative review process and enhancement of shareholder value, disclosure intentions with respect to the strategic alternative review process; commodity price outlook and general economic outlook may constitute "forward-looking information" (within the meaning of applicable Canadian securities legislation) or "forward-looking statements" (within the meaning of the United States Private Securities Litigation Reform Act of 1995, as amended) 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; unexpected decline rates in wells; wells not performing as expected; incorrect assessment of the value of acquisitions and farm-ins; failure to realize the anticipated benefits of acquisitions and farm-ins; delays resulting from or inability to obtain required regulatory approvals; changes to government regulation; 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's operations and financial results are included in reports on file with Canadian and U.S. securities regulatory authorities and may be accessed through the SEDAR website (www.sedar.com), the EDGAR website (www.sec.gov/edgar) or at Anderson's website (www.andersonenergy.ca).

The forward-looking statements contained in this financial report are made as at the date of this financial report 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.

Management's Report

Management is responsible for the preparation of the consolidated financial statements and the consistent presentation of all other financial information that is publicly disclosed. The consolidated financial statements have been prepared in accordance with the accounting policies detailed in the notes to the consolidated financial statements and in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board and include estimates and assumptions based on management's best judgement. Management maintains a system of internal controls to provide reasonable assurance that assets are safeguarded and that relevant and reliable financial information is produced in a timely manner. Independent auditors appointed by the shareholders have examined the consolidated financial statements. Their report is presented on the next page. The Audit Committee, consisting of independent members of the Board of Directors, have reviewed the consolidated financial statements with management and the independent auditors. The Board of Directors has approved the consolidated financial statements on the recommendation of the Audit Committee.

(signed) *Brian H. Dau*

Brian H. Dau
President & Chief Executive Officer

(signed) *M. Darlene Wong*

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

March 16, 2012

Independent Auditors' Report

To the Shareholders of Anderson Energy Ltd.

We have audited the accompanying consolidated financial statements of Anderson Energy Ltd., which comprise the consolidated statements of financial position as at December 31, 2011, December 31, 2010 and January 1, 2010, the consolidated statements of operations and comprehensive loss, changes in shareholders' equity and cash flows for the years ended December 31, 2011 and 2010, and notes, comprising a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Consolidated Financial Statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on our judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, we consider internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the consolidated financial position of Anderson Energy Ltd. as at December 31, 2011, December 31, 2010 and January 1, 2010, and its consolidated financial performance and its consolidated cash flows for the years ended December 31, 2011 and 2010 in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board.

(signed) *KPMG LLP*

Chartered Accountants

Calgary, Canada
March 16, 2012

Consolidated Statements of Financial Position

(Stated in thousands of dollars)

	December 31, 2011	December 31, 2010 (note 23)	January 1, 2010 (note 23)
ASSETS			
Current assets:			
Cash and cash equivalents	$ 1	$ 4,024	$ 1
Accounts receivables and accruals *(note 19)*	14,272	20,998	22,990
Prepaid expenses and deposits	2,326	3,052	3,778
Unrealized gain on derivative contracts *(note 19)*	1,384	-	-
	17,983	28,074	26,769
Deferred tax asset *(note 11)*	35,389	29,657	-
Property, plant and equipment *(note 6)*	406,947	320,673	403,207
	$ 460,319	$ 378,404	$ 429,976
LIABILITIES AND SHAREHOLDERS' EQUITY			
Current liabilities:			
Accounts payable and accruals *(note 19)*	$ 60,573	$ 46,862	$ 36,889
Unrealized loss on derivative contracts *(note 19)*	-	1,918	-
	60,573	48,780	36,889
Bank loans *(note 8)*	88,682	52,719	62,404
Convertible debentures *(note 9)*	84,796	43,460	-
Decommissioning obligations *(note 10)*	62,848	51,550	47,657
Deferred tax liability *(note 11)*	-	-	10,920
	296,899	196,509	157,870
Shareholders' equity:			
Share capital *(note 12)*	171,460	426,925	396,524
Equity component of convertible debentures *(note 9)*	5,019	2,592	-
Contributed surplus	9,385	7,921	6,338
Deficit *(note 12)*	(22,444)	(255,543)	(130,756)
	163,420	181,895	272,106
Commitments and contingencies *(note 21)*			
Subsequent events *(notes 19 and 22)*			
	$ 460,319	$ 378,404	$ 429,976

See accompanying notes to the consolidated financial statements.

On behalf of the Board:

(signed) *David G. Scobie*

Director

(signed) *Christopher L. Fong*

Director

Consolidated Statements of Operations and Comprehensive Loss

YEARS ENDED DECEMBER 31, 2011 AND 2010

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

	2011	2010 (note 23)
Oil and gas sales	$ 118,292	$ 86,457
Royalties	(13,806)	(9,011)
Revenue, net of royalties	104,486	77,446
Other income (expenses) *(note 14)*	7,388	(1,660)
	111,874	75,786
Operating expenses *(note 15)*	29,533	28,537
Transportation expenses	1,626	611
Depletion and depreciation	52,929	45,652
Impairment of property, plant and equipment *(note 7)*	35,230	153,165
General and administrative expenses *(notes 15 and 16)*	10,405	9,417
Loss from operating activities	(17,849)	(161,596)
Finance income *(note 17)*	84	96
Finance expenses *(note 17)*	(11,942)	(5,006)
Net finance expenses	(11,858)	(4,910)
Loss before taxes	(29,707)	(166,506)
Deferred income tax benefit *(note 11)*	(7,263)	(41,719)
Loss and comprehensive loss for the year	$ (22,444)	$ (124,787)
Basic and diluted loss per share *(note 13)*	$ (0.13)	$ (0.73)

See accompanying notes to the consolidated financial statements.

Consolidated Statements of Changes in Shareholders' Equity

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

	Number of Common Shares		Share capital		Equity component of convertible debentures		Contributed surplus		Deficit		Total shareholders' equity
Balance at January 1, 2010 *(note 23)*	150,500,401	$	396,524	$	-	$	6,338	$	(130,756)	$	272,106
Issued pursuant to prospectus *(note 12)*	21,900,000		31,755		-		-		-		31,755
Share issue costs, net of tax of $0.5 million	-		(1,456)		-		-		-		(1,456)
Equity component of convertible debentures, net of tax of $1.7 million *(note 9)*	-		-		2,592		-		-		2,592
Share-based payments *(note 12)*	-		-		-		1,618		-		1,618
Options exercised *(note 12)*	84,900		102		-		(35)		-		67
Loss for the year	-		-		-		-		(124,787)		(124,787)
Balance at December 31, 2010 *(note 23)*	172,485,301		426,925		2,592		7,921		(255,543)		181,895
Elimination of deficit *(note 12)*	-		(255,543)		-		-		255,543		-
Equity component of convertible debentures, net of tax of $1.5 million *(note 9)*	-		-		2,427		-		-		2,427
Share-based payments *(note 12)*	-		-		-		1,491		-		1,491
Options exercised *(note 12)*	64,400		78		-		(27)		-		51
Loss for the year	-		-		-		-		(22,444)		(22,444)
Balance at December 31, 2011	172,549,701	$	171,460	$	5,019	$	9,385	$	(22,444)	$	163,420

See accompanying notes to the consolidated financial statements.

Consolidated Statements of Cash Flows

YEARS ENDED DECEMBER 31, 2011 AND 2010

(Stated in thousands of dollars)	*2011*	*2010 (note 23)*
CASH PROVIDED BY (USED IN)		
OPERATIONS		
Loss for the year	$ (22,444)	$ (124,787)
Adjustments for:		
Unrealized (gain) loss on derivative contracts *(note 14)*	(3,302)	1,918
Gain on sale of property, plant and equipment *(note 14)*	(4,710)	(389)
Depletion and depreciation	52,929	45,652
Impairment of property, plant and equipment	35,230	153,165
Stock-based payments	960	1,020
Accretion on decommissioning obligations *(note 10)*	1,630	1,654
Accretion on convertible debentures *(note 9)*	1,434	2
Deferred income tax benefit	(7,263)	(41,719)
Decommissioning expenditures *(note 10)*	(249)	(1,549)
Changes in non-cash working capital *(note 18)*	94	5,365
	54,309	40,332
FINANCING		
Increase (decrease) in bank loans	35,963	(9,685)
Proceeds from issue of convertible debentures, net of issue costs *(note 9)*	43,860	47,700
Proceeds from issue of share capital, net of issue costs	-	29,792
Proceeds from exercise of stock options	51	67
Changes in non-cash working capital *(note 18)*	(324)	384
	79,550	68,258
INVESTING		
Property, plant and equipment expenditures	(170,906)	(113,976)
Proceeds from sale of property, plant and equipment	11,631	2,467
Changes in non-cash working capital *(note 18)*	21,393	6,942
	(137,882)	(104,567)
Increase (decrease) in cash and cash equivalents	(4,023)	4,023
Cash and cash equivalents, beginning of year	4,024	1
Cash and cash equivalents, end of year	$ 1	$ 4,024
Interest received in cash	$ 78	$ 90
Interest paid in cash	$ (4,565)	$ (2,256)

See accompanying notes to the consolidated financial statements.

Notes to the Consolidated Financial Statements

DECEMBER 31, 2011 AND DECEMBER 31, 2010

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

1. REPORTING ENTITY

Anderson Energy Ltd. and its wholly-owned subsidiaries (collectively "Anderson" or the "Company") are engaged in the acquisition, exploration and development of oil and gas properties in western Canada. Anderson is a public company incorporated and domiciled in Canada. Anderson's common shares and convertible debentures are listed on the Toronto Stock Exchange. The Company's registered office and principal place of business is 700, 555 – 4th Avenue SW, Calgary, Alberta, Canada, T2P 3E7.

2. BASIS OF PREPARATION

(a) Statement of compliance. These consolidated financial statements comply with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB").

These are the Company's first consolidated annual financial statements prepared in accordance with IFRS and IFRS 1 *First-time Adoption of International Financial Reporting Standards* has been applied. In previous years, the Company prepared its consolidated financial statements in accordance with Canadian Generally Accepted Accounting Principles in effect prior to January 1, 2011 ("Canadian GAAP"). See note 23 for details on the impact of the transition from Canadian GAAP to IFRS.

The consolidated financial statements were approved and authorized for issuance by the Board of Directors on March 16, 2012.

(b) Basis of measurement. The consolidated financial statements have been prepared on the historical cost basis except for derivative financial instruments, which are measured at fair value. The methods used to measure fair values are discussed in note 5.

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

(d) Function and nature of expenses. Expenses in the consolidated statements of operations and comprehensive loss are presented as a combination of function and nature in conformity with industry practice. Transportation expenses, depletion and depreciation, and impairment of property, plant and equipment are presented in separate lines by their nature, while operating expenses and general and administrative expenses are presented on a functional basis. Significant operating and general and administrative expenses are presented by their nature in note 15.

3. SIGNIFICANT ACCOUNTING POLICIES

The accounting policies set out below have been applied consistently to all periods presented in these consolidated financial statements except for the opening IFRS consolidated statement of financial position, which has utilized certain exemptions available under IFRS 1 as described in note 23.

(a) Basis of consolidation:

(i) Subsidiaries. Subsidiaries are entities controlled by the Company. The financial statements of subsidiaries are included in the consolidated financial statements from the date that control commences until the date that control ceases.

3. SIGNIFICANT ACCOUNTING POLICIES *(Continued)*

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

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

(b) Financial instruments:

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

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

Other. Other non-derivative financial instruments, comprising accounts receivable and accruals, accounts payable and accruals, bank loans and convertible debentures, are measured at amortized cost using the effective interest method, less any impairment losses. The Company nets all transaction costs incurred in relation to the acquisition of a financial asset or liability, against the related financial asset or liability. Bank loans and convertible debentures are recorded net of issue costs and are presented net of deferred interest payments, with interest recognized in earnings on an effective interest basis.

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

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

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

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

3. SIGNIFICANT ACCOUNTING POLICIES *(Continued)*

(c) Property, plant and equipment:

(i) Exploration and evaluation expenditures. Pre-licence costs are recognized in the statement of operations and comprehensive loss as incurred. Generally, costs designated as exploration and evaluation assets are initially capitalized, and are assessed for impairment when there are indicators of impairment present and when technical feasibility and commercial viability are established and the assets are transferred to development and production assets. Exploration and evaluation assets that are determined not to be technically feasible or commercially viable are charged to net income. As of December 31, 2011, the Company has not identified any costs as exploration and evaluation assets (December 31, 2010 – $Nil, January 1, 2010 - $Nil).

(ii) Development and production costs. Items of property, plant and equipment, which include oil and gas development and production assets, are measured at cost less accumulated depletion and depreciation and accumulated impairment losses. All costs directly associated with the development of oil and natural gas reserves are recognized as oil and natural gas interests if they extend or enhance the recoverable reserves of the underlying assets. Such costs include property acquisitions, drilling and completion costs, gathering and processing infrastructure, capitalized decommissioning obligations, directly attributable internal costs and major overhaul and turnaround activities that maintain property, plant and equipment. Repairs and maintenance and operational costs that do not extend or enhance the recoverable reserves are charged to profit or loss when incurred.

Oil and natural gas assets are grouped into cash generating units (“CGUs”) for impairment testing. The Company has grouped its development and production assets into the following CGUs: Horizontal Oil, Deep Gas, Shallow Gas and Non-Core. When significant parts of an item of property, plant and equipment, including oil and natural gas interests, have different useful lives, they are accounted for as separate items (components).

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

(d) Depletion and depreciation. The net carrying value of development or production assets is depleted using the unit of production method by reference to the ratio of production in the quarter to the related proved and probable reserves, taking into account estimated future development and decommissioning costs necessary to bring those reserves into production. For other assets, depreciation is recognized in profit or loss over the estimated useful lives of each part of an item of property, plant and equipment using the declining balance method at rates between 20% and 30% per annum. Leased assets are depreciated over the shorter of the lease term and their useful lives unless it is reasonably certain that the Company will obtain ownership by the end of the lease term. The costs of major overhaul and turnaround activities that are capitalized are depreciated on a straight-line basis over the period to the next recurrence of that set of activities, which varies from two to five years.

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

(e) Leased assets. Operating leases are not recognized on the Company’s statement of financial position.

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

3. SIGNIFICANT ACCOUNTING POLICIES *(Continued)*

(f) Impairment:

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

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

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

All impairment losses are recognized in profit or loss.

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

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

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

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

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

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

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

3. SIGNIFICANT ACCOUNTING POLICIES *(Continued)*

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

Decommissioning obligations are measured at the present value of management's expectation of the expenditures required to settle the present obligation at the reporting date. Subsequent to the initial measurement, the obligation is adjusted at the end of each period to reflect the passage of time and changes in the estimated future cash flows underlying the obligation, including changes in the discount rate used to calculate the obligation. The increase in the provision due to the passage of time is recognized as finance costs whereas increases/decreases due to changes in the estimated future cash flows are capitalized. Actual costs incurred upon settlement of the decommissioning obligations are charged against the provision to the extent the provision was established, with any difference being recognized in profit or loss under gain or loss on sale of property, plant and equipment.

(i) Revenue. Revenue from the sale of oil and natural gas is recorded when the significant risks and rewards of ownership of the product is transferred to the buyer, which is usually when legal title passes to the external party. Oil and gas sales are presented before royalty obligations, whereas revenue is presented net of royalties.

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

Fees charged to other entities for the use of pipelines, compressors and facilities owned by the Company are recognized as operating expense recoveries for use of transportation and processing assets when the usage is incurred.

Fees charged to other entities to recover overhead costs pursuant to capital and operating agreements are recognized as a reduction of general and administrative expenses in accordance with the terms of the capital and operating agreements.

(j) Transportation expenses. Transportation expenses include third-party pipeline and trucking costs incurred to transport oil, natural gas and natural gas liquids from processing and treating facilities to the point of sale.

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

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

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

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

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

3. SIGNIFICANT ACCOUNTING POLICIES *(Continued)*

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

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

(n) New standards and interpretations not yet adopted:

The IASB has issued the following new standards and amendments, all of which are effective for annual periods beginning on or after January 1, 2013. Although early adoption is permitted, the Company has not done so as of December 31, 2011.

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 closed 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.

3. SIGNIFICANT ACCOUNTING POLICIES *(Continued)*

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

IAS 12 – Income Taxes. IAS 12 "Income Taxes" was amended on December 20, 2010 to remove subjectivity in determining on which basis an entity measures the deferred tax relating to an asset. The amendment introduces a presumption that an entity will assess whether the carrying value of an asset will be recovered through the sale of the asset. The amendment to IAS 12 is effective for reporting periods beginning on or after January 1, 2012. The implementation of the issued standard is not expected to have a significant impact on the Company's financial position or results.

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

4. MANAGEMENT JUDGEMENTS AND ESTIMATES

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

(a) Judgements. The key judgements made in applying accounting policies that have the most significant effect on the amounts recognized in these consolidated financial statements are as follows:

(i) *Identification of cash generating units.* Cash generating units are defined as the lowest grouping of integrated assets that generate identifiable cash inflows that are largely independent of the cash inflows of other assets or groups of assets. The classification of assets into cash generating units requires significant judgement and interpretations with respect to shared infrastructure, geographical proximity, petroleum type and similar exposure to market risk and materiality. See note 7.

(ii) *Fair value of derivatives.* The fair value of financial instruments that are not traded in an active market is determined using valuation techniques. The Company uses its judgement to select a variety of methods and makes assumptions that are primarily based on market conditions existing at the end of each reporting period. The Company uses directly and indirectly observable inputs in measuring the value of financial instruments that are not traded in active markets, including quoted commodity prices and volatility. See note 19(d).

(b) Use of estimates. Information about assumptions and estimation uncertainties that have a significant risk of resulting in a material adjustment within the next financial year are as follows:

(i) *Estimates of oil and natural gas reserves.* Depletion and depreciation as well as the amounts used in impairment calculations are based on estimates of oil and natural gas reserves. Reserves estimates are based on engineering data, estimated future prices, expected future rates of production and the timing of future capital expenditures, all of which are subject to many uncertainties and interpretations. At least once per year, a reserves estimate is prepared by independent qualified reserves evaluators. The Company expects that, over time, its reserves estimates will be revised upward or downward based on updated information such as the results of future drilling, testing and production levels, and may be affected by changes in commodity prices. See notes 6 and 7.

4. MANAGEMENT JUDGEMENTS AND ESTIMATES *(Continued)*

(ii) *Recoverable amounts of CGUs.* The recoverable amount of a CGU used in the assessment of impairment is the greater of its VIU and its FVLCTS.

VIU is determined by estimating the present value of the future net cash flows from the continued use of the CGU, and is subject to the risks associated with estimating the value of reserves.

FVLCTS refers to the amount obtainable from the sale of a CGU in an arm's length transaction between knowledgeable, willing parties, less costs of disposal. The criteria used in the estimation of this amount are discussed in note 5.

At December 31, 2011 the recoverable amounts of the Company's CGUs were based on their estimated FVLCTS. Note 5 outlines the factors considered in estimating these amounts. The key assumptions and estimates of the value of oil and gas reserves and the existing and potential markets for the Company's oil and gas assets are valid at the time of reserves estimation and market assessment and are subject to change as new information becomes available. Changes in international and regional factors including supply and demand of commodities, inventory levels, drilling activity, currency exchange rates, weather, geopolitical and general economic environment factors may result in significant changes to the estimated recoverable amounts of CGUs. See notes 6 and 7.

(iii) *Decommissioning obligations.* 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, based on current legal and constructive requirements and technology. The estimated obligations and actual costs may change significantly due to changes in and regulations, technology, timing of the expenditure, and the discount rates used to determine the net present value of the obligations. See note 10.

(iv) *Deferred taxes.* Deferred tax assets and liabilities are measured using enacted or substantively enacted tax rates at the reporting date in effect for the period in which the temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized as part of the provision for income taxes in the period that includes the enactment date. The recognition of deferred tax assets is based on the assumption that it is probable that taxable profit will be available against which the deductible temporary differences can be utilized.

(v) *Allowance for doubtful accounts.* The Company maintains an allowance for doubtful accounts to provide for receivables which may ultimately be uncollectible. The allowance is determined in light of a number of factors including company specific conditions, economic events and the Company's historical loss experience. The allowance is assessed quarterly by a detailed formal review of accounts receivable balances. See note 19(b).

(vi) *Stock-based compensation.* The Company uses the Black-Scholes option pricing model in determining stock-based compensation expense, which requires a number of assumptions to be made, including the risk-free interest rate, expected option life, forfeiture rate, and expected share price volatility. Consequently, the actual stock based compensation expense may vary from the amount estimated. See note 12.

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

5. DETERMINATION OF FAIR VALUE

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

(a) Property, plant and equipment. Property, plant and equipment is recognized at fair value in a business combination. The fair value of property, plant and equipment is the estimated amount for which property, plant and equipment could be exchanged on the acquisition date between a willing buyer and a willing seller in an arm's length transaction after proper marketing wherein the parties had each acted knowledgeably, prudently and without compulsion.

The Company estimated the FVLCTS to determine the recoverable amounts of the Company's CGUs for impairment testing. The FVLCTS of each CGU were estimated based on consideration of the following:

(i) net present value of proved plus probable reserves using a pre-tax discount rate of 10% as determined by independent qualified reserves evaluators;

(ii) management's estimate of the fair value of undeveloped land; and

(iii) a review of the values indicated by the metrics of recent market transactions of similar assets within the oil and gas industry.

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

(b) Cash and cash equivalents, accounts receivable and accruals and accounts payable and accruals. The fair value of cash and cash equivalents, accounts receivable and accruals and accounts payable and accruals is estimated as the present value of future cash flows, discounted at the market rate of interest at the reporting date. At December 31, 2011, December 31, 2010 and January 1, 2010, the fair value of these balances approximated their carrying value due to their short term to maturity.

(c) Bank loans. The fair value of bank loans approximates their carrying value, as they bear interest at floating rates and the premium charged at December 31, 2011, December 31, 2010 and January 1, 2010 was indicative by the Company's current credit spreads.

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

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

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

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

5. DETERMINATION OF FAIR VALUE *(Continued)*

The fair value of the derivative contracts used for risk management as shown in the consolidated statements of financial position as at December 31, 2011 and December 2010 is measured using level 2. There were no derivative contracts outstanding at January 1, 2010.

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

6. PROPERTY, PLANT AND EQUIPMENT

Cost or deemed cost

		Oil and natural gas assets		*Other equipment*		*Total*
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		183,182		84		183,266
Disposals		(14,802)		-		(14,802)
Balance at December 31, 2011	$	753,875	$	1,863	$	755,738

Accumulated depletion, depreciation and impairment losses

		Oil and natural gas assets		*Other equipment*		*Total*
Opening balance at January 1, 2010	$	-	$	1,075	$	1,075
Impairment loss at January 1, 2010 *(note 7)*		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 *(note 7)*		153,165		-		153,165
Disposals		(484)		-		(484)
Balance at December 31, 2010	$	265,358	$	1,243	$	266,601
Depletion and depreciation for the year		52,794		135		52,929
Impairment loss *(note 7)*		35,230		-		35,230
Disposals		(5,969)		-		(5,969)
Balance at December 31, 2011	$	347,413	$	1,378	$	348,791

Carrying amounts

		Oil and natural gas assets		*Other equipment*		*Total*
At January 1, 2010	$	402,569	$	638	$	403,207
At December 31, 2010	$	320,137	$	536	$	320,673
At December 31, 2011	$	406,462	$	485	$	406,947

Capitalized overhead. For the year ended December 31, 2011, additions to property plant and equipment included internal overhead costs of $4.6 million (December 31, 2010 – $4.9 million).

Depletion, depreciation and impairment charges. Depletion and depreciation, impairment of property, plant and equipment, and any reversal thereof, are recognized as separate line items in the consolidated statements of operations (see note 7).

7. IMPAIRMENT LOSS AND IMPAIRMENT REVERSAL

In 2011, there were indicators of impairment and reversal of impairment for certain CGUs due to changes in forecasted commodity prices used by the Company's independent qualified reserves evaluators when compared to December 31, 2010. Accordingly, the Company tested certain CGUs for impairment or reversal and determined that the aggregate carrying value of these CGUs was $35.2 million (net of impairment reversals of $9.7 million recorded at September 30, 2011) higher than the recoverable amount and impairments were recorded.

The recoverable amounts of the CGUs were estimated based on the fair value less costs to sell (see notes 4 and 5). Carrying amounts are calculated as the net book value of property, plant and equipment less decommissioning obligations.

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

	Horizontal Oil CGU	*Deep Gas CGU*	*Shallow Gas CGU*	*Non-Core CGU*	*Total*[(1)]
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	$ -	$ 31,079	$ 183,339	$ 5,940	$ 220,358
Impairment loss (reversal) for the quarter ended September 30, 2011	-	(9,725)	3,207	5,444	(1,074)
Impairment loss for the quarter ended December 31, 2011	-	12,328	22,582	1,394	36,304
Cumulative impairment loss at December 31, 2011	$ -	$ 33,682	$ 209,128	$ 12,778	$ 255,588
Carrying amount, January 1, 2010	$ 5,750	$116,993	$ 233,237	$ 44,795	$ 400,775
Carrying amount, December 31, 2010	$ 63,687	$ 94,091	$ 124,836	$ 36,764	$ 319,378
Carrying amount, December 31, 2011	$ 215,556	$ 82,090	$ 83,216	$ 24,608	$ 405,470

(1) Carrying amounts exclude inventory and corporate assets of $2.4 million at January 1, 2010, $1.3 million at December 31, 2010 and $1.5 million at December 31, 2011.

At December 31, 2011, if the discount rate had been two percent higher or two percent lower, the impairment losses recognized would have been revised as follows:

	Horizontal Oil CGU	*Deep Gas CGU*	*Shallow Gas CGU*	*Non-Core CGU*	*Total*
Reduction of impairment using an 8 percent discount rate	$ -	$ (6,345)	$ (6,281)	$ (1,891)	$ (14,517)
Additional impairment using a 12 percent discount rate	$ -	$ 5,408	$ 5,342	$ 1,558	$ 12,308

7. IMPAIRMENT LOSS AND IMPAIRMENT REVERSAL *(Continued)*

The following table shows the differences in the future commodity prices used by the Company's independent qualified reserves evaluators at December 31, 2011 compared to December 31, 2010 for certain commodities:

	Light, Sweet Crude Edmonton ($Cdn/bbl)			*AECO Gas Price ($Cdn/MMBTU)*		
Year	*December 31, 2011*	*December 31, 2010*	*Difference*	*December 31, 2011*	*December 31, 2010*	*Difference*
2012	97.96	89.29	8.67	3.49	4.74	(1.25)
2013	101.02	90.92	10.10	4.13	5.31	(1.18)
2014	101.02	92.96	8.06	4.59	5.77	(1.18)
2015	101.02	96.19	4.83	5.05	6.22	(1.17)
2016	101.02	98.62	2.40	5.51	6.53	(1.02)
2017	101.02	101.39	(0.37)	5.97	6.76	(0.79)
2018	102.40	103.92	(1.52)	6.21	6.90	(0.69)
2019	104.47	106.68	(2.21)	6.33	7.06	(0.73)
2020	106.58	108.84	(2.26)	6.46	7.21	(0.75)

8. BANK LOANS

At December 31, 2011, total bank facilities were $135 million consisting of a $110 million extendible revolving term credit facility, a $10 million working capital credit facility and a $15 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 December 31, 2011, there were no amounts drawn under the supplemental facility.

The average effective interest rate on advances under the facilities in 2011 was 5.3% (December 31, 2010 – 4.9%). The Company had $133,500 in letters of credit outstanding at December 31, 2011 that reduce the amount of credit available to the Company.

Advances under the facilities can be drawn in either Canadian or U.S. funds and bear interest at the bank's prime lending rate, bankers' acceptance or LIBOR loan rates plus applicable margins. These margins vary from 1.50% to 6.00% depending on the borrowing option used and the Company's financial ratios.

Loans are secured by a floating charge debenture over all assets and guarantees by material subsidiaries.

The available lending limits of the facilities are reviewed semi-annually and are based on the bank syndicate's interpretations of the Company's reserves and future commodity prices. There can be no assurance that the amount of the available facilities or the applicable margins will not be adjusted at the next scheduled review on or before July 11, 2012.

9. 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 Company before June 30, 2014. On and after June 30, 2014 and prior to June 30, 2016, the Series B Debentures are redeemable at the Company'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 Company 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".

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

Both the Series A and the Series B Debentures were determined to be compound instruments. As the Series A and 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 A and 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 A and Series B Debentures, such that the carrying amount of the financial liability will equal the $50 million and $46 million principal balance at maturity respectively.

9. CONVERTIBLE DEBENTURES *(Continued)*

The following table indicates the convertible debenture activities:

	Proceeds	Debt component	Equity component
Balance, January 1, 2010	$ -	$ -	$ -
Series A Debentures issued pursuant to prospectus, 7.5% interest rate, due January 31, 2016[(1)]	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, 7.25% interest rate, due June 30, 2017[(2)]	46,000	41,849	4,151
Issue costs	(2,140)	(1,947)	(193)
Deferred tax	-	-	(1,531)
Accretion expense	-	1,434	-
Balance, December 31, 2011	$ 91,560	$ 84,796	$ 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.

10. DECOMMISSIONING OBLIGATIONS

	December 31, 2011	December 31, 2010
Balance at January 1	$ 51,550	$ 47,657
Provisions incurred	4,878	2,945
Total abandonment expenditures	(249)	(1,549)
Provisions disposed	(1,316)	(75)
Change in estimates	6,355	918
Accretion expense	1,630	1,654
Ending balance	$ 62,848	$ 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 Company has estimated the net present value of the decommissioning obligations to be $62.8 million as at December 31, 2011 (December 31, 2010 – $51.6 million) based on an undiscounted inflation-adjusted total future liability of $80.8 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. At December 31, 2011 the liability has been calculated using an inflation rate of 2.0% (December 31, 2010 – 2.0%) and discounted using a risk-free rate of 0.9% to 3.1% (December 31, 2010 – 0.8% to 4.4%) depending on the estimated timing of the future obligation.

11. TAXES

The temporary differences that gave rise to the Company's deferred income tax liabilities (assets) at December 31, 2011, December 31, 2010 and January 1, 2010 were as follows:

	December 31, 2011	December 31, 2010	January 1, 2010
Deferred income tax liabilities (assets):			
Property, plant and equipment	$ 1,395	$ (275)	$ 33,296
Decommissioning obligations	(15,712)	(12,888)	(11,914)
Derivative contracts	346	(508)	-
Convertible debentures	2,820	1,650	-
Share issue costs	(1,909)	(2,229)	(1,985)
Non-capital losses	(29,843)	(18,004)	(9,289)
Current income deferred	7,514	2,597	812
Ending balance	$ (35,389)	$ (29,657)	$ 10,920

The Company has recognized a net deferred tax asset based on the independently evaluated reserves report as cash flows are expected to be sufficient to realize the deferred tax asset.

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

	December 31, 2011	December 31, 2010
Loss before taxes	$ (29,707)	$ (166,506)
Combined federal and provincial tax rates	26.5%	28.0%
Expected deferred income tax benefit	(7,872)	(46,622)
Increase in income taxes resulting from:		
Changes in expected deferred tax rates	365	4,624
Non-deductible stock-based compensation and other	244	279
Deferred income tax benefit	$ (7,263)	$ (41,719)

At December 31, 2011, the Company has loss carryforwards of approximately $119 million that will expire between 2025 and 2030. The Company expects to be able to fully utilize these losses. The statutory tax rate decreased to 26.5% in 2011 from 28% in 2010 as a result of tax legislation enacted in 2007.

A continuity of the net deferred income tax (asset) liability is detailed in the following tables:

(in thousands of dollars)	*Balance January 1, 2010*	*Recognized in profit or loss*	*Recognized in equity*	*Balance December 31, 2010*
Property, plant and equipment	$ 33,296	$ (33,570)	$ -	$ (275)
Decommissioning obligations	(11,914)	(974)	-	(12,888)
Derivative contracts	-	(508)	-	(508)
Convertible debentures *(note 9)*	-	-	1,650	1,650
Share issue costs *(note 12)*	(1,985)	263	(507)	(2,229)
Non-capital losses	(9,289)	(8,715)	-	(18,004)
Current income deferred	812	1,785	-	2,597
	$ 10,920	$ (41,719)	$ 1,143	$ (29,657)

11. TAXES *(Continued)*

(in thousands of dollars)	*Balance January 1, 2011*	*Recognized in profit or loss*	*Recognized in equity*	*Balance December 31, 2011*
Property, plant and equipment	$ (275)	$ 1,670	$ -	$ 1,395
Decommissioning obligations	(12,888)	(2,824)	-	(15,712)
Derivative contracts	(508)	854	-	346
Convertible debentures *(note 9)*	1,650	(361)	1,531	2,820
Share issue costs	(2,229)	320	-	(1,909)
Non-capital losses	(18,004)	(11,839)	-	(29,843)
Current income deferred	2,597	4,917	-	7,514
	$ (29,657)	$ (7,263)	$ 1,531	$ (35,389)

12. 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.

	Number of Common Shares	*Amount*
Balance at January 1, 2010	150,500,401	$ 396,524
Issued pursuant to prospectus[(1)]	21,900,000	31,755
Share issue costs	-	(1,963)
Tax effect of share issue costs	-	507
Stock options exercised	84,900	67
Transferred from contributed surplus on stock option exercise	-	35
Balance at December 31, 2010	172,485,301	$ 426,925
Elimination of deficit	-	(255,543)
Stock options exercised	64,400	51
Transferred from contributed surplus on stock option exercise	-	27
Balance at December 31, 2011	172,549,701	$ 171,460

(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, 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 purchase common shares of the Company. Options are granted using an exercise price of stock options equal to the weighted average trading price of the Company's common shares for the five trading days prior to the date of the grant. Options have terms of either five or ten years and vest equally over a three year period starting on the first anniversary date of the grant. Changes in the number of options outstanding during the years ended December 31, 2011 and 2010 are as follows:

12. SHARE CAPITAL *(Continued)*

	December 31, 2011			December 31, 2010		
	Number of options		Weighted average exercise price	Number of options		Weighted average exercise price
Outstanding at January 1	12,006,232	$	2.32	10,258,756	$	3.22
Granted during the year	4,484,800		0.74	3,950,250		1.06
Exercised during the year	(64,400)		0.79	(84,900)		0.79
Expired during the year	(1,564,150)		4.27	(1,430,124)		5.78
Forfeited during the year	(848,300)		1.01	(687,750)		1.44
Ending balance	14,014,182	$	1.69	12,006,232	$	2.32
Exercisable, end of year	6,764,582	$	2.60	6,111,399	$	3.53

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

Range of exercise prices	*Number of options*		*Weighted average exercise price*	*Weighted average remaining life (years)*
$0.45 to $0.67	172,500	$	0.48	4.9
$0.68 to $1.02	6,255,100		0.74	3.8
$1.03 to $1.54	3,620,950		1.08	3.6
$2.33 to $3.50	625,950		2.68	1.6
$3.51 to $4.90	3,339,682		4.00	0.6
Total at December 31, 2011	14,014,182	$	1.69	2.9

The weighted average common 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:

		December 31, 2011		*December 31, 2010*
Fair value at grant date	$	0.38	$	0.55
Common share price	$	0.74	$	1.06
Exercise price	$	0.74	$	1.06
Volatility		59%		58%
Option life		5 years		5 years
Dividends		0%		0%
Risk-free interest rate		1.7%		2.3%
Forfeiture rate		15%		15%

This estimated forfeiture rate is adjusted to the actual forfeiture rate when each tranche vests. Stock-based compensation cost of $1.0 million (December 31, 2010 – $1.0 million) was expensed during the year ended December 31, 2011. In addition, stock-based compensation expense of $0.5 million (December 31, 2010 – $0.6 million) was capitalized during the year ended December 31, 2011.

13. LOSS PER SHARE

Basic and diluted loss per share were calculated as follows:

	December 31, 2011	December 31, 2010
Loss for the year	$ (22,444)	$ (124,787)
Weighted average number of common shares (basic) *(in thousands of shares)*		
Common shares outstanding at January 1	172,485	150,500
Effect of stock options exercised	53	17
Effect of other shares issued	-	19,782
Weighted average number of common shares (basic)	172,538	170,299
Basic and diluted loss per share	$ (0.13)	$ (0.73)

The average market value of the Company's common 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 year ended December 31, 2011, 14,014,182 options (December 31, 2010 – 12,006,232 options) and 59,316,889 common shares reserved for convertible debentures (December 31, 2010 – 32,258,065) were excluded from calculating dilutive earnings as they were anti-dilutive.

14. SUPPLEMENTAL REVENUE AND EXPENSE RECOVERY INFORMATION

Revenues for all product sales and services and expense recoveries are as follows:

	December 31, 2011	December 31, 2010
Revenue from oil and gas sales, net of royalties	$ 104,486	$ 77,446
Other income (expense):		
Realized loss on derivative contracts	$ (624)	$ (131)
Unrealized gain (loss) on derivative contracts	3,302	(1,918)
Gain on sale of property, plant and equipment	4,710	389
	$ 7,388	$ (1,660)
Expenses recovered from third parties:		
Operating expense recoveries for use of transportation and processing assets	$ 2,864	$ 2,860
General and administrative overhead expense recoveries	568	540
	$ 3,432	$ 3,400

Major customers. For the year ended December 31, 2011, revenues of $33.9 million (December 31, 2010 – $43.2 million), $30.8 million (December 31, 2010 – $2.2 million) and $28.6 million (December 31, 2010 – $16.0 million) were derived from the external customers who individually amounted to 10 percent or more of the Company's revenues.

15. EXPENSES BY NATURE

	December 31, 2011	December 31, 2010
External services[(1)]	$ 9,970	$ 8,093
Third-party gathering, processing and treating services	8,790	9,508
Employee benefit expenses *(note 16)*	7,229	6,640
Operating leases and equipment rents[(2)]	3,893	3,781
Repairs and maintenance	3,494	2,680
Materials and supplies	2,313	1,456
Other expenses	4,249	5,796
Expenses by nature	$ 39,938	$ 37,954
Above costs allocated to the following functions:		
Operating	$ 29,533	$ 28,537
General and administrative	10,405	9,417
Total operating and general and administrative expenses	$ 39,938	$ 37,954

(1) External services include professional fees, contract operators, consulting fees, design fees and other operating and administrative services.

(2) Operating leases and equipment rents include office leases, surface leases, and equipment rents.

16. EMPLOYEE BENEFIT EXPENSES

General and administrative expenses include employee benefit expense as follows:

	December 31, 2011	December 31, 2010
Short-term employee benefits	$ 9,726	$ 9,190
Share-based payments	1,491	1,619
Total employee remuneration	11,217	10,809
Capitalized portion of employee remuneration	(3,988)	(4,169)
	$ 7,229	$ 6,640

Employees include all staff and directors of the Company. Personnel expenses directly attributed to capital activities have been capitalized and included in property, plant and equipment.

17. FINANCE INCOME AND EXPENSES

	December 31, 2011	December 31, 2010
Income:		
Interest income on cash equivalents	$ 6	$ -
Other	78	96
Expenses:		
Interest and financing costs on bank loans	(3,201)	(3,306)
Interest on convertible debentures	(5,631)	(11)
Accretion on convertible debentures	(1,434)	(2)
Accretion on decommissioning obligations	(1,630)	(1,654)
Other	(46)	(33)
Net finance expenses	$ (11,858)	$ (4,910)

18. SUPPLEMENTAL CASH FLOW INFORMATION

Changes in non-cash working capital is comprised of:

	December 31, 2011	December 31, 2010
Source (use) of cash		
Accounts receivable and accruals	$ 6,726	$ 1,992
Prepaid expenses and deposits	726	726
Accounts payable and accruals	13,711	9,973
	$ 21,163	$ 12,691
Related to operating activities	$ 94	$ 5,365
Related to financing activities	$ (324)	$ 384
Related to investing activities	$ 21,393	$ 6,942

19. 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 management's 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 customers. The maximum exposure to credit risk is as follows:

	December 31, 2011	December 31, 2010	January 1, 2010
Cash and cash equivalents	$ 1	$ 4,024	$ 1
Accounts receivable and accruals	14,272	20,998	22,990
	$ 14,273	$ 25,022	$ 22,991

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 customer or joint venture partner.

A substantial portion of the Company's accounts receivable are with customers in the oil and gas industry and are subject to normal industry credit risks. Receivables from oil and natural gas customers are normally collected on the 25th day of the month following the related sale of oil and gas production. The Company's policy to mitigate credit risk associated with these balances is to establish commercial relationships with large customers. The Company historically has not experienced any collection issues with its oil and natural gas customers. Receivables from joint venture partners are typically collected within ninety days.

19. FINANCIAL RISK MANAGEMENT *(Continued)*

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

The Company does not typically obtain collateral from oil and natural gas customers 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 December 31, 2011 was $0.9 million (December 31, 2010 – $1.0 million, January 1, 2010 - $1.6 million). This allowance was mostly created in prior years and is associated with prior corporate acquisitions and potential joint venture billing disputes. The Company wrote-off $0.1 million in receivables during the year ended December 31, 2011 (December 31, 2010 – $0.6 million). 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:

		Carrying Amount				
		December 31, 2011		*December 31, 2010*		*January 1, 2010*
Oil and natural gas customers	$	10,307	$	9,286	$	8,213
Joint venture partners		2,335		7,989		7,790
Other		1,630		3,723		6,987
	$	14,272	$	20,998	$	22,990

As at December 31, 2011, December 31, 2010 and January 1, 2010, the Company's accounts receivable and accruals, net of allowance for doubtful accounts was aged as follows:

Aging		*December 31, 2011*		*December 31, 2010*		*January 1, 2010*
Not past due	$	13,608	$	18,960	$	22,402
Past due by less than 120 days		163		1,706		537
Past due by more than 120 days		501		332		51
Total	$	14,272	$	20,998	$	22,990

These amounts exclude 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 objective 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 8. The Company also attempts to match its payment cycle with collection of oil and natural gas revenue on the 25th of each month.

19. 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 December 31, 2011:

Financial Liabilities	*Less than one year*	*One to two years*	*Two to three years*	*Three to four years*	*Four to five years*	*Five to six years*
Non-derivative financial liabilities						
Accounts payable and accruals [(1)]	$ 60,573	$ -	$ -	$ -	$ -	$ -
Bank loans – principal [(2)]	-	88,682	-	-	-	-
Convertible debentures						
- Interest [(1)]	5,523	7,085	7,085	7,085	5,210	1,667
- Principal	-	-	-	-	50,000	46,000
Total	$ 66,096	$ 95,767	$ 7,085	$ 7,085	$ 55,210	$ 47,667

(1) Accounts payable and accruals includes $3.4 million of interest relating to convertible debentures. The total cash interest payable in less than one year on the convertible debentures is $9.0 million.

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

The following table shows the Company's accounts payable and accruals:

	Carrying Amount December 31, 2011	*December 31, 2010*	*January 1, 2010*
Trade payables	$ 24,188	$ 19,550	$ 19,443
Accruals [(1)]	36,385	27,312	17,446
	$ 60,573	$ 46,862	$ 36,889

(1) Accruals include amounts for goods and services that have been received or supplied but have not been paid, invoiced or formally agreed with the supplier as of the reporting date. These accruals relate to both operating and capital activities.

(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 December 31, 2011 or December 31, 2010.

Interest rate risk. Interest rate risk is the risk that future cash flows will fluctuate as a result of changes in market interest rates. The interest charged on the outstanding bank loans fluctuates with the interest rates posted by the lenders. The Company has not entered into any mitigating interest rate hedges or swaps, however 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 9). Had the borrowing rate on bank loans been 100 basis points higher (or lower) throughout the year ended December 31, 2011, earnings would have been affected by $0.4 million (December 31, 2010 – $0.3 million) based on the average bank debt balance outstanding during the year.

19. FINANCIAL RISK MANAGEMENT *(Continued)*

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 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 sales contracts. The Company does not enter into commodity contracts other than to meet the Company's expected sale requirements.

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

Type of Contract[(1)]	*Commodity*	*Volume*		*Weighted Average Fixed Price (NYMEX Canadian $)*	*Remaining Period*
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 December 31, 2011, the Company estimates that it would receive $1.4 million to terminate these contracts.

There were no derivative contracts outstanding at January 1, 2010. 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:

		December 31, 2011		*December 31, 2010*
Current asset	$	1,384	$	-
Current liability		-		(1,918)
Net asset (liability) position	$	1,384	$	(1,918)

The fair value of derivative contracts at December 31, 2011 would have been impacted as follows had the oil prices used to estimate 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 prices	$	(412)	$	412

In January 2012, the Company entered into fixed price swap contracts for an average of 500 barrels per day of crude oil for February to December 2012 at a weighted average NYMEX crude oil price of Canadian $103.75 per barrel.

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. The Company realized $1.2 million of gains associated with these contracts.

19. FINANCIAL RISK MANAGEMENT *(Continued)*

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

The Company manages its capital structure and makes adjustments to it in the light of changes in economic conditions and the risk characteristics of the underlying petroleum and natural gas assets. The Company's capital structure includes shareholders' equity of $163.4 million, bank loans of $88.7 million, convertible debentures with a face value of $96.0 million and the cash working capital deficiency of $44.0 million, which excludes the current portion of unrealized gains 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 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. Funds from operations in the quarter, annualized current quarter funds from operations and total net debt to funds from operations are not defined by IFRS and therefore are referred to as non-GAAP measures.

	December 31, 2011	*December 31, 2010*
Bank loans	$ 88,682	$ 52,719
Current liabilities[(1)]	60,573	46,862
Current assets[(1)]	(16,599)	(28,074)
Net debt before convertible debentures	$ 132,656	$ 71,507
Convertible debentures (liability component)	84,796	43,460
Total net debt	$ 217,452	$ 114,967
Cash from operating activities in the quarter	$ 16,462	$ 10,488
Decommissioning expenditures in the quarter	146	118
Changes in non-cash working capital in the quarter	389	(1,324)
Funds from operations in the quarter	$ 16,997	$ 9,282
Annualized current quarter funds from operations	$ 67,988	$ 37,128
Net debt before convertible debentures to funds from operations	2.0	1.9
Total net debt to funds from operations	3.2	3.1

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

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

19. FINANCIAL RISK MANAGEMENT *(Continued)*

As at December 31, 2011, the Company's ratio of net debt before convertible debentures to annualized funds from operations was 2.0 to 1 (December 31, 2010 – 1.9 to 1). As at December 31, 2011, the Company's ratio of total net debt to annualized funds from operations was 3.2 to 1 (December 31, 2010 – 3.1 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 increase in the ratio from December 31, 2010 is the result higher capital spending in 2011, partially offset by higher funds from operations as a result of the transition to an oil weighted company. As new crude oil production is brought on-stream at higher expected operating margins, the debt to funds from operations ratio is expected to decrease.

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

20. RELATED PARTY TRANSACTIONS

Key management personnel are comprised of all officers and directors of the Company.

On June 8, 2011, the Company issued 1,575 Series B Convertible Debentures to key management personnel 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.

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 $31.8 million bought deal offering of common shares before commissions and expenses.

Compensation of key management personnel was as follows:

	December 31, 2011	December 31, 2010
Salaries and other short-term employee benefits	$ 2,469	$ 2,058
Share-based payments	902	820
	$ 3,371	$ 2,878
Capitalized portion of key management personnel compensation	(1,552)	(1,285)
	$ 1,819	$ 1,593

21. COMMITMENTS AND CONTINGENCIES

(a) Capital commitments. As at December 31, 2011 the Company had commitments for future capital expenditures in the amount of $0.5 million that are expected to be incurred during the first quarter of 2012. In addition to these capital commitments, the Company has entered into "farm-in" agreements whereby the Company may earn working interests in oil and gas properties in exchange for undertaking capital spending programs to develop the properties. In certain farm-in agreements, the Company is subject to non-performance fees if it does not fulfill its capital spending obligations. As at December 31, 2011 the Company is committed to fulfilling the following farm-in obligations.

Cardium Horizontal Well Program - Oil. The Company has farm-in obligations to drill six gross (4.5 net capital) horizontal wells in the Cardium geological formation prior to dates ranging from August 1, 2012 to September 30, 2012. One agreement has a $100,000 non-performance fee clause should the Company fail to drill the well. Another agreement pertains to two wells; there is a $100,000 non-performance fee should the Company fail to drill both wells, and if only one well is drilled, the Company would also forfeit fifty per cent of the interest in the first well drilled under the agreement.

21. COMMITMENTS AND CONTINGENCIES *(Continued)*

Edmonton Sands Well Program – Natural Gas. In 2009, the Company committed to a 200 well drilling and completion program in the Edmonton Sands geological formation (the "Program") under a farm-in agreement with a large international oil and gas company (the "Farmor") from which the Company will earn an interest in up to 120 sections of land. The Company is obligated to complete the Program or before March 31, 2013 and has an option to continue the farm-in transaction until March 1, 2014 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 Company and the Farmor can then jointly develop the lands on denser drilling spacing under terms of an operating agreement.

As of December 31, 2011, the Company had drilled 126 wells under the farm-in agreement and deferred the drilling of the remaining 74 gross (53.5 net capital) wells until 2013 due to depressed natural gas prices. A $550,000 penalty is payable for each well not drilled under the commitment as of March 31, 2013, 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 approximately $10 million.

(b) Operating lease commitments. The Company leases various plant and equipment, vehicles, and surface land locations under cancellable operating lease agreements. Surface lease arrangements may be cancelled at any time following reclamation of any site used in the Company's operations. For plant and equipment and vehicle leases, the Company may terminate the leases at any time, subject to certain immaterial conditions and guarantees.

The Company leases various offices and computer software under non-cancellable operating lease agreements. The head office lease terminates on November 30, 2012, while other lease terms are between one and three years, and the majority of lease agreements are renewable at the end of the lease period at the prevailing market rate.

The minimum future payments under non-cancellable operating leases are as follows:

	December 31, 2011
Less than one year	$ 1,952
Between one year and five years	467
More than five years	-
	$ 2,419

The total operating lease expenditure charged to the income statement during the year is disclosed in note 15.

(c) Other commitments and contingencies. The Company has entered into firm service gas transportation agreements in which the Company guarantees certain minimum volumes of natural gas will be shipped on various gas transportation systems. The terms of the various agreements expire in one to eight years. If no volumes were shipped pursuant to the agreements, the maximum amounts payable under the guarantees based on current tariff rates are as follows:

	2012	*2013*	*2014*	*2015*	*2016*	*Thereafter*
Firm service commitment	$ 1,255	$ 871	$ 679	$ 608	$ 95	$ 299
Firm service committed volumes *(MMcfd)*	19	10	5	4	3	9

The Company entered into an agreement for gas gathering services with a minimum fee payable of approximately $244,000 per year until November 30, 2018. To date, the gathering fees paid by the Company for gas volumes transported on the gathering system have exceeded the minimum requirements.

21. COMMITMENTS AND CONTINGENCIES *(Continued)*

The Company entered into a facilities construction and operation agreement pursuant to which it has guaranteed a minimum revenue to the crude oil pipeline operator related to minimum volumes of crude oil shipments through the new facilities and pipeline. The minimum revenue guaranteed is approximately $257,000 per contract year for the first five years commencing with the in-service date of the facilities and pipeline, which occurred in October 2011. If the Company exceeds the minimum volume requirement in a single year, the excess is carried forward as a credit to the minimum revenue guarantee in the subsequent year. If no volumes were shipped, the annual payment under the guarantee would be approximately $257,000 each year for five years. To date, no payments have been required under this guarantee.

22. SUBSEQUENT EVENTS

On February 21, 2012 the Company issued a news release to announce the Board of Directors' decision to initiate a process to identify, examine and consider a range of strategic alternatives available to the Company with a view to enhancing shareholder value. Strategic alternatives may include, but are not limited to, a sale of all or a material portion of the assets of Anderson, either in one transaction or in a series of transactions, the outright sale of the Company, or a merger or other strategic transaction involving Anderson and a third party. There are no guarantees or assurances that the process will result in a transaction or a series of transactions or, if a transaction or a series of transactions are undertaken, the terms or timing of any such transaction or series of transactions.

Subsequent to December 31, 2011, the Company sold or has entered into agreements to sell minor properties for $6.3 million in gross proceeds (subject to adjustments).

23. RECONCILIATION FROM CANADIAN GAAP TO IFRS

These are the Company's first annual consolidated financial statements prepared in accordance with IFRS.

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

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

(in thousands of dollars)	*Canadian GAAP*	*Impairment (note 23b)*	*Decommi-ssioning (note 23d)*	*Share-based payments (note 23e)*	*Flow through shares (note 23f)*	*Deferred taxes (note 23h)*	*IFRS*
ASSETS							
Current assets:							
Cash	$ 1	$ -	$ -	$ -	$ -	$ -	$ 1
Accounts receivable and accruals	22,990						22,990
Prepaid expenses and deposits	3,778						3,778
	26,769	-	-	-	-	-	26,769
Property, plant and equipment *(note 23a)*	470,400	(67,193)					403,207
	$ 497,169	$ (67,193)	$ -	$ -	$ -	$ -	$ 429,976
LIABILITIES AND EQUITY							
Current liabilities:							
Accounts payable and accruals	$ 36,889	$ -	$ -	$ -	$ -	$ -	$ 36,889
Bank loans	62,404						62,404
Decommissioning obligations	33,879		13,778				47,657
Deferred tax liability *(note 23h)*	31,278	(16,914)	(3,444)			-	10,920
	164,450	(16,914)	10,334	-	-	-	157,870
Shareholders' equity:							
Share capital	391,637				5,336	(449)	396,524
Contributed surplus	6,104			234			6,338
Deficit *(note 23i)*	(65,022)	(50,279)	(10,334)	(234)	(5,336)	449	(130,756)
	332,719	(50,279)	(10,334)	-	-	-	272,106
	$ 497,169	$ (67,193)	$ -	$ -	$ -	$ -	$ 429,976

23. RECONCILIATION FROM CANADIAN GAAP TO IFRS *(Continued)*

Statement of financial position at December 31, 2010:

(in thousands of dollars)	*Canadian GAAP*	*Impairment (note 23b)*	*Decommi-ssioning (note 23d)*	*Share-based payments (note 23e)*	*Depletion and depreciation (note 23c)*	*Other PP&E adjs (note 23c)*	*Flow through shares (note 23f)*	*Convertible debentures (note 23g)*	*Deferred taxes (note 23h)*	*IFRS*
ASSETS										
Current assets:										
Cash and cash equivalents	$ 4,024	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 4,024
Accounts receivable and accruals	20,998									20,998
Prepaid expenses and deposits	3,052									3,052
Deferred tax asset	508								(508)	-
	28,582	-	-	-	-	-	-	-	(508)	28,074
Property, plant and equipment *(note 23a)*	506,533	(220,358)	2,185	(322)	33,071	(436)				320,673
	$ 535,115	$ (220,358)	$ 2,185	$ (322)	$ 33,071	$ (436)	$ -	$ -	$ (508)	$ 348,747
LIABILITIES AND EQUITY										
Current liabilities:										
Accounts payable and accruals	$ 46,862	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 46,862
Unrealized loss on derivative contracts	1,918									1,918
	48,780	-	-	-	-	-	-	-	-	48,780
Bank loans	52,719									52,719
Convertible debentures	43,460									43,460
Decommissioning obligations	36,320		15,075			155				51,550
Deferred tax liability (asset) *(note 23h)*	20,045	(55,407)	(3,222)		8,268	(483)		1,650	(508)	(29,657)
	201,324	(55,407)	11,853	-	8,268	(328)	-	1,650	(508)	166,852
Shareholders' equity:										
Share capital	422,038						5,336		(449)	426,925
Equity component of convertible debentures	4,242							(1,650)		2,592
Contributed surplus	8,164			(243)						7,921
Deficit *(note 23i)*	(100,653)	(164,951)	(9,668)	(79)	24,803	(108)	(5,336)		449	(255,543)
	333,791	(164,951)	(9,668)	(322)	24,803	(108)	-	(1,650)	-	181,895
	$ 535,115	$ (220,358)	$ 2,185	$ (322)	$ 33,071	$ (436)	$ -	$ -	$ (508)	$ 348,747

23. RECONCILIATION FROM CANADIAN GAAP TO IFRS *(Continued)*

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

(in thousands of dollars)	*Canadian GAAP*	*Impairment (note 23b)*	*Decommi-ssioning (note 23d)*	*Share-based payments (note 23e)*	*Depletion and depreciation (note 23c)*	*Other PP&E adjs (note 23c)*	*IFRS*
Oil and gas sales	$ 86,457	$ -	$ -	$ -	$ -	$ -	$ 86,457
Royalties	(9,011)						(9,011)
Revenue	77,446	-	-	-	-	-	77,446
Realized loss on derivative contracts	(131)						(131)
Unrealized loss on derivative contracts	(1,918)						(1,918)
Gain on sale of property, plant and equipment	-					389	389
	75,397	-	-	-	-	389	75,786
Operating expenses	28,537						28,537
Transportation expenses	611						611
Depletion and depreciation	78,723				(33,071)		45,652
Impairment of property, plant and equipment	-	153,165					153,165
General and administrative expenses, including stock-based compensation	8,908			(155)		664	9,417
Loss from operating activiites	(41,382)	(153,165)	-	155	33,071	(275)	(161,596)
Finance income	96						96
Finance expenses, including accretion	(5,894)		888				(5,006)
Net finance expenses	(5,798)	-	888	-	-	-	(4,910)
Loss before taxes	(47,180)	(153,165)	888	155	33,071	(275)	(166,506)
Deferred income tax reduction	(11,549)	(38,493)	222	-	8,268	(167)	(41,719)
Loss and comprehensive loss for the year	$ (35,631)	$ (114,672)	$ 666	$ 155	$ 24,803	$ (108)	$ (124,787)

23. RECONCILIATION FROM CANADIAN GAAP TO IFRS *(Continued)*

Notes to reconciliations

(a) IFRS 1 Exemptions:

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.

Business Combinations. The Company applied the IFRS 1 exemption and did not retrospectively revalue business combinations that occurred before January 1, 2010 in accordance with IFRS 3, Business Combinations. Accordingly, there were no adjustments made to the Company's January 1, 2010 financial statements as a result of this exemption.

Borrowing Costs. The Company also applied the IFRS 1 exemption which allowed first-time adopters to use the transitional provisions set out in IAS 23, Borrowing Costs and set the effective date of the standard as January 1, 2010, which is the date of the Company's transition to IFRS. Accordingly, there were no adjustments made to the Company's January 1, 2010 financial statements as a result of this exemption.

Refer to notes 23(d) and 23(e) for further discussion on IFRS 1 exemptions taken for decommissioning obligations and share-based payments.

(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 the recoverable amount (greater of value in use or fair value less costs to sell) compared with the asset's carrying amount to 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 was based on undiscounted cash flows using asset groupings with both independent cash inflows and cash outflows.

As a result of applying the deemed cost exemption at January 1, 2010, the Company recorded an impairment of $67.2 million with a corresponding reduction in property, plant and equipment. For the year ended December 31, 2010 the Company recognized additional impairments of $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 unit 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.

At January 1, 2010, there were no amounts recorded as a result of the policy differences as discussed above. For the year ended December 31, 2010, the use of proved plus probable reserves in conjunction with lower net book values due to impairments in the Company's Shallow Gas, Deep Gas and Non-core CGUs resulted in a decrease to depletion and depreciation of $33.1 million with a corresponding increase to property, plant and equipment.

23. RECONCILIATION FROM CANADIAN GAAP TO IFRS *(Continued)*

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 $0.4 million during the year ended December 31, 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 expense by $0.7 million during the year ended December 31, 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 $0.3 million at December 31, 2010 with a corresponding decrease to the deferred tax liability.

(d) IAS 37 Adjustments – Provisions, Contingent Liabilities and Contingent Assets. Consistent with IFRS, decommissioning obligations (asset retirement obligations under Canadian GAAP) were measured under Canadian GAAP based on the estimated cost of decommissioning, discounted to their net present value upon initial recognition. Under Canadian GAAP, asset retirement obligations were discounted at a credit adjusted risk fee rate of eight to 10 percent. Under IFRS, the estimated cash flows to abandon and remediate the Company's wells and facilities has been risk adjusted, therefore the provision is discounted at a risk free rate of one to four percent depending upon the estimated timelines to reclamation. Under IFRS, decommissioning obligations are also required to be re-measured at each reporting period to incorporate changes in future cash flow estimates, timelines to reclamation as well as discount rates used in present valuing the obligations.

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 December 31, 2010, using risk-free rates of one to four percent, depending on the estimated timing of the future obligation, the Company increased its decommissioning obligations by $15.1 million from Canadian GAAP. The Company also increased the value of its plant, property and equipment for December 31, 2010 by $2.2 million for new obligations incurred during 2010.

For the year ended December 31, 2011, accretion expense decreased by $0.9 million under IFRS compared to Canadian GAAP as a result of higher initial decommissioning obligations being recognized under IFRS and lower discount rates being used. Under IFRS, accretion on decommissioning obligations is included in finance expenses as opposed to Canadian GAAP where these amounts were included in depletion, depreciation and accretion.

(e) IFRS 2 Adjustments – Share-based Payments. Under Canadian GAAP, the Company recognized stock-based compensation expense on a straight-line basis through the date of full vesting and incorporated a forfeiture rate, 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 estimating a forfeiture rate is no longer optional.

23. RECONCILIATION FROM CANADIAN GAAP TO IFRS *(Continued)*

The Company applied the IFRS 1 exemption for equity instruments which vested before the transition date and did not retroactively restate them. All unvested options at transition date were retroactively restated in accordance with IFRS 2 with the adjustment going through opening retained earnings. As a result, the Company recorded an additional $0.2 million in contributed surplus at January 1, 2010 for unvested options with the offset going to opening retained earnings.

For the year ended December 31, 2010, the Company reduced contributed surplus by $0.5 million and reduced the amount of stock-based compensation capitalized by $0.3 million for a net reduction in stock-based compensation expense of $0.2 million. Under Canadian GAAP, stock-based compensation expense was disclosed separately on the consolidated statement of operations and comprehensive loss. Under IFRS, stock-based compensation expense 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 January 1, 2010, the Company recorded an additional $5.3 million to share capital with a corresponding reduction in retained earnings for flow through shares that had been previously issued and fully renounced at transition.

(g) Convertible Debentures. Under Canadian GAAP, the Company did not record a deferred tax difference on its convertible debentures. Under IFRS, the Company is required to record the deferred tax difference between the fair value of the liability component of the convertible debentures and the tax value of the convertible debentures with the difference being booked against the equity component of convertible debentures. As a result, the Company recorded $1.7 million in deferred tax against the equity component of convertible debentures at 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:

	December 31, 2010	*January 1, 2010*
Impairment of plant, property and equipment *(note 23b)*	(55,407)	(16,914)
Depletion and depreciation *(note 23c)*	8,268	-
Decommissioning obligation *(note 23d)*	(3,222)	(3,444)
Convertible debentures *(note 23g)*	1,650	-
Other adjustments *(note 23c)*	(483)	-
Decrease in deferred tax liability	$ (49,194)	$ (20,358)

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

Under Canadian GAAP, the Company was required to disclose future income taxes in the same current or long-term classification from which the timing differences arose. As such at December 31, 2010, the Company reported $0.5 million as a current asset related to timing differences that would reverse in one year. There is no such requirement under IFRS, therefore the Company removed the separate disclosure of current deferred taxes.

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

23. RECONCILIATION FROM CANADIAN GAAP TO IFRS *(Continued)*

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

	December 31, 2010	January 1, 2010
IImpairment of plant, property and equipment *(note 23b)*	$ (164,951)	$ (50,279)
Decommissioning obligations *(note 23d)*	(9,668)	(10,334)
Flow through shares *(note 23f)*	(5,336)	(5,336)
Depletion and depreciation *(note 23c)*	24,803	-
General and administrative expenses *(note 23c)*	(497)	-
Gain on sale of plant, property and equipment *(note 23c)*	389	-
Deferred taxes on share issue costs *(note 23h)*	449	449
Stock-based compensation *(note 23e)*	(79)	(234)
Decrease in retained earnings	$ (154,890)	$ (65,734)

(j) Adjustments to the Company's Statements of Cash Flows 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 $0.7 million to operating cash flows, with and equal and opposite effect on investing cash flows for the year ended December 31, 2010.

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Member of:
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(2) Compensation & Corporate Governance Committee
(3) Reserves Committee
(4) Special Committee

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Independent Engineers

GLJ Petroleum Consultants Ltd.

Legal Counsel

Bennett Jones LLP

Registrar & Transfer Agent

Valiant Trust Company

Stock Exchange

The Toronto Stock Exchange
Symbol AXL, AXL.DB, AXL.DB.B

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Blaine M. Chicoine
Vice President, Drilling and Completions

Sandra M. Drinnan
Vice President, Land

Philip A. Harvey
Vice President, Exploitation

Jamie A. Marshall
Vice President, Exploration

Patrick M. O'Rourke
Vice President, Production

Abbreviations used

AECO – intra-Alberta Nova inventory transfer price
CBM – coal bed methane
bbl – barrel
bpd – barrels per day
Mstb – thousand stock tank barrels
Mbbls – thousand 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
MMBOE – million barrels of oil equivalent
GJ – gigajoule
Mcf – thousand cubic feet
Mcfd – thousand cubic feet per day
MMcf – million cubic feet
MMcfd – million cubic feet per day
Bcf – billion cubic feet
NGL – natural gas liquids
MMBTU – million British thermal units
WTI – West Texas Intermediate

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