Anderson Energy Announces 2014 First Quarter Results

13.05.2014 | Marketwired

CALGARY, May 13, 2014 - Anderson Energy Ltd. ("Anderson" or the "Company") (TSX:AXL) announces its operating and financial results for the first quarter ended March 31, 2014.

HIGHLIGHTS

- The average initial production rate over the first 30 days for the seven Cardium horizontal light oil wells drilled in the winter program was 459 BOED per well.

- Production in the first quarter of 2014 was 2,958 BOED of which 39% was oil and NGL compared to 2,112 BOED (26% oil and NGL) for the fourth quarter of 2013 (net of properties sold in the fourth quarter of 2013).

- Funds from operations were $5.5 million in the first quarter of 2014 compared to negative funds from operations of $0.3 million in the fourth quarter of 2013.

- The operating netback was $34.51 per BOE in the first quarter of 2014 compared to $12.35 per BOE in the fourth quarter of 2013 (adjusted for properties sold in the quarter).

- The Board of Directors has approved a 2014 capital budget of $46 million. Annual production for 2014 is estimated to average approximately 3,200 BOED (36% oil and NGL). Exit production for 2014 is estimated to be approximately 3,700 BOED (42% oil and NGL). In addition to the seven wells drilled this winter, the Company is planning to drill 15 gross (12.6 net) Cardium and Mannville light oil horizontal wells from the second quarter of 2014 to spring breakup 2015.

- GLJ Petroleum Consultants ("GLJ") have completed an interim reserves report of all of the Company's oil and natural gas properties effective April 30, 2014. This report includes the impact of the winter drilling program, a positive change in the GLJ price deck and is net of production to April 30, 2014. Proved developed producing ("PDP"), total proved ("TP") and total proved plus probable("P&P") BOE reserves were 11%, 3% and 9% higher than reported at year end 2013.

- At April 30, 2014, the Company had 3,811 MBOE PDP reserves (33% oil and NGL), 5,472 MBOE TP reserves (36% oil and NGL) and 9,583 MBOE P&P reserves (43% oil and NGL).

- Anderson's total P&P pre-tax 10% net present value ("NPV 10") of reserves at April 30, 2014 was $132.8 million, a 32% increase over the reported December 31, 2013 value. Undeveloped land was valued at $3.4 million at December 31, 2013.

- Cardium P&P reserves were 6.1 MMBOE representing 63% of total P&P reserves volumes and 82% of total P&P NPV 10 reserves value.

- The Company has agreed to an increase its bank facility from $28 million to $ 31 million, subject to customary closing conditions. As of today's date, the Company is not drawn on its bank facility.

- 115 gross (73.3 net) light oil horizontal drilling locations have been identified in the Cardium and Mannville zones. Only 31% of the net locations are recognized as P&P locations in the interim reserves report. Approximately 97% of the net locations are Company operated.

FINANCIAL AND OPERATING HIGHLIGHTS

Three months ended March 31 (thousands of dollars, unless otherwise stated)	2014		Change
Oil and gas sales (1)	$14,522	$16,863	(14%)
Revenue, net of royalties (1)	$13,195	$15,268	(14%)
Funds from operations (2)	$5,538	$5,486	1%
Funds from operations per share			
Basic and diluted (2)	$0.03	$0.03	-
Adjusted earnings (loss) before taxes (3)	$544	$(5,113)	111
Adjusted earnings (loss) before taxes per share - basic and diluted(3)	$-	$(0.03)	100%
Earnings (loss)	$544	$(5,113)	111%
Earnings (loss) per share			
Basic and diluted	$-	$(0.03)	100%
Capital expenditures (net of proceeds on dispositions)	$16,032	$7,662	109%
Bank loans and other working capital (deficiency) (2)	$(993)	$(66,783)	99%
Convertible debentures	$89,517	$87,277	3%
Shareholders' equity	$28,840	$128,110	(77%)
Average shares outstanding (thousands):			
Basic	172,550	172,550	-
Diluted	172,943	172,550	-
Ending shares outstanding (thousands)	172,550	172,	
Average daily sales volumes:			
Oil (bpd)	969	1,529	(37%)
NGL (bpd)	170	203	(16%)
Natural gas (Mcfd)	10,920	14,759	(2
Barrels of oil equivalent (BOED) (4)	2,958	4,191	
Average prices:			
Oil ($/bbl)	$97.36	$84.83	15%
NGL ($/bbl)	$69.13	$61.77	12%
Natural gas ($/Mcf)	$5.01	$2.94	70%
Barrels of oil equivalent ($/BOE) (4)	$54.54	$44.70	
Realized loss on derivative contracts ($/BOE)	$(1.53)	$(1.55)	1%
Royalties ($/BOE)	$4.99	$4.23	18%
Operating costs ($/BOE)	$13.28	$11.93	11%
Transportation costs ($/BOE)	$0.23	$0.21	10%
Operating netback ($/BOE) (3)	$34.51	$26.78	29%
Wells drilled (gross)	4	2	100%

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

(2) Funds from operations, funds from operations per share, working capital and working capital (deficiency) are considered additional GAAP measures. Refer to the section entitled "Additional GAAP Measures" in the Management's Discussion and Analysis ("MD&A") for a more complete description of these additional GAAP measures. Bank loans of $nil (March 31, 2013 - $55.1 million) were included in working capital as defined therein.

(3) Adjusted earnings (loss) before taxes, adjusted earnings (loss) before taxes per share and operating netback per BOE are considered non-GAAP measures. Refer to the section entitled "Non-GAAP Measures" in the MD&A for a more complete description of these non-GAAP terms, reconciliations to more closely related GAAP measures, and the purposes for which management uses the non-GAAP measures. These non-GAAP measures may not be comparable with the calculation of similar measures for other entities.

(4) 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.

STRATEGY

The Company's business plan is to pursue growth of its asset base and cash flow, and increase its financial flexibility to meet its obligations when they become due. Coming out of the strategic alternatives process, the Company is smaller in terms of production, has cash in the bank and an unused bank operating line. Its convertible debentures mature in 2016 and 2017.

Admittedly, the current share price is weak. The overall market for public junior oil and gas companies has been weak in the past few years. The share price reflects the uncertainty associated with the recently completed strategic alternatives process, the lack of drilling activity during the process and a debt to cash flow ratio that is currently too high. With the bank debt issues resolved, Anderson intends to focus on rebuilding its asset base by drilling Cardium and Mannville horizontal light oil wells, and growing its Cardium and Mannville horizontal oil drilling inventory in the Willesden Green, West Pembina and Buck Lake areas. In its first full quarter since completion of the strategic alternatives process, the Company has shown progress on all fronts with increasing oil production, cash flow and reserves. The Company expects it will take time for the market to appreciate the growth in annual oil production and growth potential of its asset base. The longer term debenture maturities give the Company time to rebuild its asset base. By resuming a drilling program and controlling the infrastructure in its Cardium oil properties where feasible, the Company should be able to increase oil production and operating netbacks. A strategy of increasing oil assets, production and cash flow should also support a higher borrowing base over time.

Anderson will continue to focus on reducing average well payouts. The goal is to have Cardium wells pay out in approximately one year, on average, by continuing to improve the profitability of these operations. The Company believes this goal can be achieved by continuing to implement new approaches in Cardium horizontal drilling and completion technologies, and by keeping costs as low as possible.

Recent technological changes include repositioning the trajectory of the horizontal well within the Cardium zone to maximize frac effectiveness, and using dissolvable frac balls. In 2014, the Company plans to drill its first long-reach horizontal oil well that is expected to traverse up to 3,000 metres of horizontal Cardium net pay. It is anticipated that long-reach horizontal wells will access Cardium reserves in two sections of land as opposed to the current one section of land per horizontal well. There is a capital cost benefit to drilling an extended reach well over two sections as compared to two wells traversing one section of land each. There is also a reserves benefit with longer horizontal wells due to additional reservoir contact.

Where it can, the Company strives to operate its own oil and gas infrastructure and attract third parties to utilize this infrastructure on a processing fee basis in order to reduce overall operating costs. Currently, the Company operates over 90% of its production and all of its current drilling operations.

Anderson is developing new light oil horizontal plays on its existing acreage in the Mannville and Belly River and is planning to drill one of these plays in 2014.

The Company currently has no plans to dispose of its Cardium oil assets. In addition, the Company currently has no plans to buy back common shares or convertible debentures with normal course issuer bids. The Company's plan is to continue to grow its asset base by investing in its light oil drilling opportunities.

Anderson will continue to look for ways to optimize, rationalize, consolidate and improve the profitability of its shallow gas business. In the fourth quarter of 2013 and the first quarter of 2014, the Company disposed of unprofitable shallow gas assets. The Company's remaining shallow gas properties are profitable at current natural gas prices. The Company is not planning any significant new investments in the shallow gas business, and may dispose of some or all of its remaining shallow gas assets.

For 2014, the Company estimates that oil and NGL ("liquids") production will be approximately 36% of total production, and that revenue from liquids will be approximately 66% of total revenue. The Company expects the percentage contribution of liquids to total revenue to grow, and estimates that its production will be balanced between natural gas and liquids by the end of 2015.

WINTER DRILLING PROGRAM

This winter, Anderson embarked on a seven well drilling program. The program started a few weeks later than planned in order to use the same drilling rig that was used last year, which helped to keep drilling costs low. Two of the seven wells in the program were originally planned to be on-stream in late January, but were delayed due to a third party natural gas plant that incurred a plant outage which lasted almost a month. The third party plant processed the solution gas from these two wells. This outage was resolved and these two oil wells and the related solution gas were brought on-stream a month later than planned. The other five wells in the program were unaffected by the third party plant outage.

The best performing well to date from this winter's drilling program averaged 697 bpd of oil, 755 bpd of oil and NGL and 1,119 BOED in its first 30 days of initial production ("IP 30"). This well has demonstrated the best IP 30 performance of any horizontal well drilled by the Company since its entry into the Cardium play in 2010.

Results from the program to date are shown in table below:

Average Gross IP 30	
Number of wells in average	7
Barrels of oil per day (BOPD)	241
Barrels of oil and NGL per day (BPD)	276
Barrels of oil equivalent per day (BOED)	459

The comparable IP 30 data for the Company' previous slick water drilling program was 453 BOED for seven wells.

Short-term production rates can be influenced by flush production effects from fracture stimulations in horizontal wellbores and may not be indicative of longer-term production performance. Individual well performance may vary.

In its March 31, 2014 press release, the Company reported the potential for a 1 MMcfd production shut-in related to a National Energy Board Order imposing a reduction in TransCanada Pipelines' maximum operating pressure on a pipeline lateral in Central Alberta. The Operator of the gas plant on the pipeline lateral has since informed the Company that the Company will not have its production curtailed by this Order. The Company will continue to monitor this situation.

LIGHT OIL HORIZONTAL DRILLING INVENTORY

The Company's undeveloped light oil horizontal drilling inventory at May 12, 2014, is outlined below:

Prospect Area (number of drilling locations)	Gross	Net*
Willesden Green Cardium	81	58.3
West Pembina/Buck Lake Cardium	26	7.7
Mannville/Belly River	8	7.3
Total Light Oil Horizontal Drilling Inventory	115	73.3

* Net is net revenue interest

GLJ booked undeveloped reserves to 22.4 net locations at April 30, 2014. The locations booked by GLJ include 1.8 net locations related to the Mannville/Belly River prospect area. GLJ's booked locations are included in the drilling inventory table shown above.

Six gross (3.2 net) locations are on lands where the Company's development plan is to drill extended reach horizontal wells traversing 1.5 to 2 miles of land.

The Company has a potential drilling inventory of 95 gross (58 net) horizontal locations in the Second White Specks light oil play. Offsetting industry activity has not yet proved this play to be commercial; therefore, it is not included in the drilling inventory table above.

The Company also has an extensive shallow gas drilling inventory in the Edmonton Sands. At the present time, the Company's business strategy does not include any near-term plans for shallow gas drilling.

ACQUISITIONS AND DISPOSITIONS

On February 28, 2014, the Company closed a transaction whereby it disposed of 107 wellbores, 31 compressor stations and 880 Mcfd of forecasted 2014 shallow gas production. This property had a historical operating cost of approximately $4.00 per Mcf and average royalties of approximately 10%. This non-operated property has generated negative cash flow in the past two years and was expected to have negative cash flow in 2014 if not sold. This transaction is accretive on a cash flow basis to the Company as it reduces annualized operating expenses by $1.3 million and reduces decommissioning obligations by $3.1 million. These lands had no further development potential.

Year-to-date, the Company has completed or committed to $1.9 million in net property acquisitions related to Cardium and Mannville prospects, and the sale of $0.9 million in shallow gas and undeveloped land.

2014 CAPITAL BUDGET

The Board of Directors has approved a 2014 capital budget of $46 million. Sixty-eight percent of the budget is directed at drilling and completion expenditures to drill 12 net Cardium and Mannville horizontal light oil drilling prospects. Twenty-four percent of the expenditures are directed at equipping, tie-in and facility expenditures and the remaining funds are directed at land, abandonments and capitalized G&A expenditures. With this capital program, the annual production guidance for 2014 has increased to approximately 3,200 BOED (36% oil and NGL), up from the guidance provided by Company in its March 31, 2014 press release (2,600 BOED, 33% oil and NGL). The Company estimates 2014 exit production to be approximately 3,700 BOED (42% oil and NGL).

In addition to the seven well 2013/2014 Cardium winter program, the Company is planning to drill 15 gross (12.6 net) Cardium and Mannville light oil horizontal wells from the second quarter of 2014 to spring breakup 2015. The Company continues to evaluate farm-in and property acquisitions in its Cardium and Mannville light oil focus areas. Should the Company add additional farm-in commitments, it would substitute those commitments into its 2014 capital program and defer the current budgeted locations until 2015.

COMMODITY PRICES

A comparison of Anderson's average wellhead oil price to various market prices is presented below. Average wellhead prices are before the impact of any financial derivative contracts used for risk management. The difference between Anderson's wellhead price and WTI Canadian is due to the price differential between Cushing, Oklahoma and Edmonton, oil transportation costs from the field to Edmonton and adjustments for oil quality.

CRUDE OIL PRICES

Three months ended March 31	2014	2013
WTI - $US	$98.62	$94.34
WTI - $Cdn	$108.83	$95.16
Differential from Cushing to Edmonton - $US per bbl	$8.35	$6.91
Edmonton Par - $Cdn per bbl	$100.04	$88.31
Anderson average wellhead price per bbl	$97.36	$84.83

A comparison of Anderson's average plant gate natural gas price to various market prices is presented below. Average plant gate prices are before the impact of any financial derivative or fixed price contracts used for risk management. The difference between the AECO price and Anderson's plant gate price is due to transportation costs and the heat content of the gas. Financial derivative and fixed price contracts reduced the average price received for natural gas to $4.59 per Mcf in the first quarter of 2014.

NATURAL GAS PRICES

Three months ended March 31	2014	2013
NYMEX US$ per MMBtu	$4.72	$3.48
AECO $CAD per GJ	5.36	3.04
AECO $CAD per MMBtu	5.66	3.20
Anderson average plant gate price per Mcf	$5.38	$2.94

The 2014 monthly WTI Canadian oil prices were approximately $112.14 per bbl in April and $109.12 per bbl to date in May. Differentials from Cushing, Oklahoma to Edmonton were approximately $8.32 US per bbl in April and $4.12 US per bbl in May. AECO natural gas prices were approximately $4.52 per GJ ($4.77 per MMBtu) in April and $4.45 per GJ ($4.69 per MMBtu) month to date in May.

Going forward, Anderson estimates that light oil prices will stay strong but volatile and will be influenced by geopolitical events. Cushing, Oklahoma to Edmonton differentials are also expected to continue to be volatile, as well as movements in the US dollar exchange rate.

In the first quarter of 2014, North American winter weather contributed to much stronger natural gas pricing than we have seen in recent years. The winter weather also reduced North American natural gas storage to levels not seen for many years. This should contribute to stronger natural gas pricing this summer compared to recent prior years.

Natural gas prices are influenced by weather events and are tempered by the increasing supply of new shale gas. Until meaningful exports of natural gas commence from North America through liquefied natural gas projects, the Company believes that natural gas prices will be range-bound by weather events.

FINANCIAL RESULTS

Funds from operations were $5.5 million in the first quarter of 2014 as compared to $(0.3) million in the fourth quarter of 2013. On a BOE basis, oil and gas sales averaged $54.54 per BOE in the first quarter of 2014 compared to $36.49 per BOE in the fourth quarter of 2013. During the first quarter of 2014, oil and NGL revenue represented 66% of total revenue. The Company's operating netback was $34.51 per BOE in the first quarter of 2014 as compared to $14.81 per BOE for the fourth quarter of 2013 ($12.35 per BOE excluding properties sold in the fourth quarter of 2013). Both quarters were negatively impacted by losses on financial derivative or fixed price contracts (2014 - $2.91 per BOE, 2013 - $2.96 per BOE). The increase in operating netback was primarily driven by higher oil and gas prices. Anderson's operating netback for Cardium properties in the first quarter of 2014 was $60.30 per BOE as compared to $39.54 per BOE in the fourth quarter of 2013 ($38.55 per BOE adjusted for properties sold in the fourth quarter of 2013), exclusive of hedging.

The Company reported earnings of $0.5 million in the first quarter of 2014 compared to a loss of $2.4 million in the fourth quarter of 2013 and a loss of $5.1 million for the first quarter of 2013.

Field capital expenditures were $14.5 million in the first quarter of 2014 as compared to $7.4 million in the fourth quarter of 2013. Capital investments in the first quarter of 2014 were focused primarily on the drilling, completion, equipping and tie-in of Cardium horizontal oil wells. In the first quarter of 2014, the Company spent $1.0 million net of dispositions on the acquisition of undeveloped land and producing properties as opposed to net dispositions of $79.8 million in the fourth quarter of 2013.

HEDGING

Derivative contracts

At March 31, 2014, the following fixed price swap contract based on the AECO 5A natural gas price was outstanding and recorded at estimated fair value:

Period	Weighted average volume (GJ/d)	Weighted average Canadian ($/GJ)
April 1, 2014 to December 31, 2014	2,500	$3.55

Subsequent to March 31, 2014 the Company entered into the following derivative contract for crude oil:

Period	Weighted average volume (bpd)	Weighted average WTI Canadian ($/bbl)
May 1, 2014 to December 31, 2014	500	$110.00

Fixed price contracts

The Company entered into physical contracts to sell 2,500 GJs per day of natural gas for January 1, 2014 to

December 31, 2014 at an average AECO price of $3.72 per GJ. All of the remaining natural gas production is being sold at the monthly average of AECO 5A daily index prices.

RESERVES

GLJ Petroleum Consultants ("GLJ"), an independent evaluator, has completed a modified corporate look-ahead analysis of the Company's reserves (the "GLJ Interim Report"). The previous 2013 year end evaluation has been updated to an April 30, 2014 effective date, utilizing GLJ's April 1, 2014 price deck and a modified "look ahead" analysis approach. More details on the methodology followed under this approach are provided in Management's Discussion and Analysis for the three months ended March 31, 2014. The GLJ Interim Report was prepared for the Company for the purpose of providing a corporate update and is not the equivalent of a full year end reserves report. At April 30, 2014, the Company had 3,811 MBOE PDP reserves (33% oil and NGL), 5,472 MBOE TP reserves (36% oil and NGL) and 9,583 MBOE P&P reserves (43% oil and NGL). The GLJ price forecast used in the evaluation is shown in Management's Discussion and Analysis for the three months ended March 31, 2014.

The increased reserves in the GLJ Interim Report reflect the impact of the winter drilling program, higher commodity price forecasts, and additional drilling locations associated with recent property acquisitions. The Cardium formation represents approximately 47%, 51% and 63% respectively of PDP, TP and P&P total BOE reserves volumes and 79%, 80% and 82% respectively of the total Company PDP, TP and P&P NPV 10 value.

SUMMARY OF OIL AND GAS RESERVES

Gross Working Interest	April 30, 2014					December 31, 2013				
Oil and Gas Reserves	Oil (Mbbls)	NGL (Mbbls)	Gas (MMcf)	Total (MBOE)	Pre-tax NPV ($M)	Oil (Mbbls)	NGL (Mbbls)	Gas (MMcf)	Total (MBOE)	Pre-tax NPV ($M)
Proved developed producing	1,020	246	15,269	3,811	63,375	792	216	14,639	3,447	43,153
Proved developed non-producing	53	34	4,176	784	6,660	128	25	3,683	767	7,527
Total proved	1,624	341	21,043	5,472	81,097	1,608	313	20,336	5,311	61,608
Proved plus probable	3,469	643	32,829	9,583	132,813	3,150	565	30,642	8,822	100,312

UNDEVELOPED LAND

Anderson has 226,343 gross (132,355 net) developed acres and 65,048 gross (27,988 net) undeveloped acres of land at December 31, 2013. Undeveloped land was valued at $3.4 million by management at the end of 2013.

ANNUAL GENERAL MEETING

The Company's annual shareholders' meeting (the "Meeting") is scheduled for 10:00 a.m. on June 18, 2014 at the Westwinds Conference Room, 2nd Floor Selkirk House, 555 4th Avenue S.W., Calgary, Alberta.

On May 12, 2014, the Company's Board of Directors approved an advance notice by-law (the "By-Law") which will apply to nominations of directors at the Meeting. The By-Law is in effect until it is confirmed, confirmed as amended or rejected by shareholders at the Meeting. Additional details will be provided in the Company's management information circular to be distributed prior to the Meeting.

SUMMARY

The Company has made considerable progress in the last few months by demonstrating oil production growth, oil reserves growth and reserves value growth. Anderson is now embarking on a significant high impact Cardium and Mannville horizontal oil drilling program. The Company continues to rationalize and improve the profitability of its shallow gas assets and add to its horizontal light oil drilling inventory with farm-in and property acquisitions. The management and staff are very excited about the future oil production growth drilling program and the Company's prospects in the Willesden Green Cardium and Mannville plays.

For further information on the Company, please refer to the investor presentation at www.andersonenergy.ca.

Brian H. Dau, President & Chief Executive Officer

May 13, 2014

Management's Discussion and Analysis

FOR THE THREE MONTHS ENDED MARCH 31, 2014 AND 2013

The following management's discussion and analysis ("MD&A") is dated May 12, 2014 and should be read in conjunction with the unaudited condensed interim consolidated financial statements of Anderson Energy Ltd. ("Anderson" or the "Company") for the three months ended March 31, 2014 and the audited consolidated financial statements and MD&A of Anderson for the years ended December 31, 2013 and 2012.

In addition to generally accepted accounting principles ("GAAP") measures, this MD&A contains additional conversion measures, non-GAAP measures, additional GAAP measures and forward-looking statements. Readers are cautioned that the MD&A should be read in conjunction with Anderson's disclosure under the headings "Conversion Measures," "Non-GAAP Measures," "Additional GAAP Measures" and "Forward-Looking Statements" included at the end of this MD&A.

All references to dollar values are to Canadian dollars unless otherwise stated. Production volumes are measured upon sale unless otherwise noted. Definitions of the abbreviations used in this discussion and analysis are located on the last page of this document.

REVIEW OF FINANCIAL RESULTS

Overview

Anderson completed its seven well winter drilling program in the first quarter. These horizontal Cardium wells contributed to a significant increase in oil production, funds from operations and reserves from the fourth quarter of 2013.

The Company ended the first quarter of 2014 with no bank debt and a working capital deficiency(1) of $1.0 million at March 31, 2014, compared to bank loans plus a working capital deficiency of $66.8 million at March 31, 2013. During the three month period ended March 31, 2014, the Company generated $5.5 million in funds from operations(2) and reported earnings of $0.5 million. The Company also invested $16.0 million in capital expenditures net of minor property dispositions.

Asset dispositions in the fourth quarter of 2013 that impacted production volumes and financial results in the first quarter of 2014 included the sale of the Garrington and Ferrier Cardium oil and natural gas properties that had produced approximately 1,000 BOED (65% oil and NGL), and the sale of shallow gas properties that produced approximately 860 Mcfd (143 BOED). In the first quarter of 2014, the Company disposed of a further 880 Mcfd (147 BOED) of unprofitable shallow gas production.

In light of the recent changes in the Company's assets and production profile due to the sale of properties in the fourth quarter of 2013, the 2013/2014 winter drilling program, and higher commodity prices, a comparison to the fourth quarter of 2013 has been added to the following table, "Summary of Production, Prices, Sales, and Funds from Operations", to provide additional clarity as to the variables contributing to the

Company's improved financial performance during the three months ended March 31, 2014 from the previous three-month period ended December 31, 2013.

(1) Working capital or working capital (deficiency) are considered additional GAAP measures. Refer to the section entitled "Additional GAAP Measures" at the end of this MD&A.

(2) Funds from operations are considered an additional GAAP measure. Refer to "Funds from Operations" in this section and the section entitled "Additional GAAP Measures" at the end of this MD&A.

SUMMARY OF PRODUCTION, PRICES, REVENUE, AND FUNDS FROM OPERATIONS

Production

Three months ended	March 31	December 31	March 31
	2014	2013	2013
Oil (bpd)	969	537	1,529
NGL (bpd)	170	166	203
Natural gas (Mcfd)	10,920	10,467	14,759
Total (BOED)(5)	2,958	2,448	4,191

Prices

Three months ended	March 31	December 31	March 31
	2014	2013	2013
Oil ($/bbl)(1)	$97.36	$84.26	$84.83
NGL ($/bbl)	69.13	61.60	61.77
Natural gas ($/Mcf)(1)(2)	5.01	3.19	2.94
Total ($/BOE)(3)(5)	$54.54	$36.49	$44.70

Oil and gas sales

Three months ended	March 31	December 31	March 31
(thousands of dollars)	2014	2013	2013
Oil(1)	$8,487	$4,162	$11,671
NGL	1,057	943	1,129
Natural gas(1)(2)	4,920	3,067	3,902
Royalty and other	58	45	161
Total oil and gas sales	$14,522	$8,217	$16,863

Funds from operations

Three months ended	March 31	December 31	March 31
(thousands of dollars)	2014	2013	20
Cash from operating activities	$2,375	$(230)	$5,171
Changes in non-cash working capital	2,982	(671)	
Decommissioning expenditures	181	595	
Funds from operations(4)	$5,538	$(306)	$5,486

1. Excludes the realized loss of $0.4 million and unrealized loss of $0.5 million on natural gas derivative contracts, respectively during the three months ended March 31, 2014 (December 31, 2013 - $0.9 million loss and $0.9 million gain on oil contracts respectively) (March 31, 2013 - $0.6 million loss and $1.1 million loss on oil contracts, respectively).

2. Includes loss on fixed price natural gas contracts of $0.4 million during the three months ended March 31,

2014 (December 31, 2013 and March 31, 2013 - $nil).

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

4. Funds from operations are considered an additional-GAAP measure Refer to "Funds from Operations" in this section and the section entitled "Additional GAAP Measures" at the end of this MD&A.

5. Barrels of oil equivalent ("BOE") may be misleading, particularly if used in isolation. Refer to the section entitled "Conversion Measures" at the end of this MD&A.

Production

Average production volumes in the first quarter of 2014 were 2,958 BOED compared to 2,448 BOED in the fourth quarter of 2013 and 4,191 BOED in the first quarter in 2013.

Properties sold in the fourth quarter of 2013 contributed approximately 336 BOED to the production reported the fourth quarter of 2013.

Overall, production volumes in the first quarter of 2014 decreased 29% compared to the first quarter of 2013, but increased 21% from volumes reported in the fourth quarter of 2013 (40% net of production from sold properties).

The first quarter of 2014 has benefitted from increased oil production as a result of the 2013/2014 winter drilling program. One of the seven wells in the winter drilling program came on-stream in December 2013 and the remaining six wells came on-stream at various times during the first quarter of 2014.

As discussed more fully in the "Business Prospects" section later in this MD&A, the Company has revised its 2014 capital program, and has increased its 2014 production guidance to approximately 3,200 BOED (36% oil and NGL), up from the guidance provided by Company in its March 31, 2014 press release (2,600 BOED, 33% oil and NGL). The Company estimates 2014 exit production to be approximately 3,700 BOED (42% oil and NGL).

In its March 31, 2014 press release, the Company reported the potential for a 1 MMcfd production shut-in related to a National Energy Board Order imposing a reduction in TransCanada Pipelines' maximum operating pressure on a pipeline lateral in Central Alberta. The Operator of the gas plant on the pipeline lateral has since informed the Company that the Company will not have its production curtailed by this Order. The Company will continue to monitor this situation.

Prices

World and North American benchmark prices for oil remain volatile. Differentials between WTI oil prices and prices received in Alberta are also volatile due to factors including refining demand and pipeline capacity. Anderson sells its oil at monthly average Edmonton Par prices less quality differentials, transportation and marketing fees. Light, sweet oil differentials between Cushing, Oklahoma and Edmonton, Alberta are affected by transportation and market factors. Differentials in the first quarter of 2014 averaged $8.35 US discount per bbl (March 31, 2013 - $6.91 US per bbl).

Natural gas prices improved significantly in the first few months of 2014 due to higher demand related to colder weather conditions in North America, but longer term markets have not seen the same increase. In the first quarter of 2014, AECO 5A prices averaged approximately $5.36 Cdn per GJ. Forward strip prices for AECO are approximately $3.95 Cdn per GJ for 2015 and $3.80 Cdn per GJ for 2016.

The Company's average natural gas sales price was $5.01 per Mcf for the three months ended March 31, 2014, 57% higher than the fourth quarter of 2013 price of $3.19 per Mcf and 70% higher than the first quarter of 2013 price of $2.94 per Mcf. This price includes the effect of the fixed price contracts discussed below. The average price before the effect of the fixed price contracts was $5.38 per Mcf. The average price after the effect of both the fixed price contracts and the derivative contracts discussed below was $4.59 per Mcf.

Derivative contracts

At March 31, 2014, the following fixed price swap contract based on the AECO 5A natural gas price was outstanding and recorded at estimated fair value:

Period Weighted average volume (GJ/d)
Weighted average Cdn ($/GJ)
April 1, 2014 to December 31, 2014
2,500 $3.55

By comparison, AECO 5A averaged $5.36 Cdn per GJ in the first quarter of 2014 and $3.35 Cdn per GJ in the fourth quarter of 2013. During 2014, AECO 5A has averaged $4.06 Cdn per GJ for January, $7.19 Cdn per GJ for February and $5.01 Cdn per GJ in March.

Derivative contracts on natural gas had the following impact on the unaudited consolidated statements of operations for the three months ended March 31, 2014 (the comparative numbers for the three months ended March 31, 2013 were on oil derivative contracts):

Three months ended
March 31
(thousands of dollars)
2014 2013
Realized loss on derivative contracts
$407 $586
Unrealized loss on derivative contracts
464
1,071
Total loss on derivative contracts
$871 $1,657
Subsequent to March 31,
2014 the Company entered into the
following derivative
contract for crude oil:
Period Weighted average volume (bpd)
Weighted average WTI Canadian ($/bbl)
May 1, 2014 to December 31, 2014 500
$110.00

Fixed price contracts

The Company entered into physical contracts to sell 2,500 GJs per day of natural gas for January 1, 2014 to December 31, 2014 at an average AECO price of $3.72 Cdn per GJ. All of the remaining natural gas production is being sold at the monthly average of AECO 5A daily index prices.

Royalties

For the first quarter of 2014, the average rate for royalties was 8.9% of revenue compared to 11.3% of revenue in the fourth quarter of 2013 and 9.5% of revenue in the first quarter of 2013. Oil wells drilled by the Company on Crown lands qualify for royalty incentives that reduce average Crown royalties for periods of up to 36 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 and year to year.

Three months ended March 31	2014	2013
Gross Crown royalties	6.9%	5.3%
Gas cost allowance	(2.0%)	(1.3%)
Other royalties	4.0%	5.5%
Total royalties	8.9%	9.5%
Total royalties ($/BOE)	$ 4.99	$4.23

Operating expenses

Operating expenses were $3.5 million ($13.28 per BOE) in the first quarter of 2014 compared to $3.2 million

($14.31 per BOE) in the fourth quarter of 2013 and $4.5 million ($11.93 per BOE) in the first quarter of 2013. Operating expenses on a per BOE basis were affected by the impact of the property sales on the product sales mix of the Company. The oil properties sold by the Company during the fourth quarter of 2013 generally contributed to lower operating costs per BOE than many of the Company's natural gas properties. Following the sale of the oil properties, the Company had a larger proportion of natural gas properties that contributed to higher operating costs per BOE. As expected, the winter drilling program in the Cardium formation resulted in a greater proportion of operating costs and volumes from the Cardium areas, thereby lowering the Company's average operating costs on a per BOE basis during the first quarter of 2014 compared to the fourth quarter of 2013. The disposition of high operating cost natural gas properties in the first quarter of 2014 should help to lower operating costs per BOE in future quarters.

Transportation expenses

For the first quarter of 2014, transportation expenses were $0.23 per BOE compared to $0.28 per BOE in the fourth quarter of 2013 and $0.21 per BOE in the first quarter of 2013. The increase in transportation expenses in the first quarter of 2014 compared to the first quarter of 2013 was due to higher NGL trucking costs. Also, following the sale of the Garrington and Ferrier properties in the fourth quarter of 2013, the remainder of the Company's production from oil properties has been trucked to the point of sale.

OPERATING NETBACK

Three months ended March 31 (thousands of dollars)	2014	2013
Revenue(1)(2)(3)	$14,522	$16,863
Realized loss on derivative contracts	(407)	(586)
Royalties	(1,327)	(1,595)
Operating expenses	(3,536)	(4,503)
Transportation expenses	(62)	(77)
Operating netback(4)	$9,190	$10,102
Sales volume (MBOE)(5)	266.3	377.2
Per BOE(5)		
Revenue(1)(2)(3)	$54.54	$44.70
Realized loss on derivative contracts	(1.53)	(1.55)
Royalties	(4.99)	(4.23)
Operating expenses	(13.28)	(11.93)
Transportation expenses	(0.23)	(0.21)
Operating netback(4)	$34.51	$26.78

1. Excludes the realized loss of $0.4 million and unrealized loss of $0.5 million on natural gas derivative contracts, respectively during the three months ended March 31, 2014 (March 31, 2013 - $0.6 million loss and $1.1 million loss on oil contracts, respectively).

2. Includes loss on fixed price natural gas contracts of $0.4 million during the three months ended March 31, 2014 (March 31, 2013 - $nil).

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

4. Operating netback is considered a non-GAAP measure. Refer to the section entitled "Non-GAAP Measures" at the end of this MD&A.

5. Barrels of oil equivalent ("BOE") may be misleading, particularly if used in isolation. Refer to the section entitled "Conversion Measures" at the end of this MD&A.

Depletion and depreciation

Depletion and depreciation was $5.7 million ($21.23 per BOE) in the first quarter of 2014 compared to $4.3 million ($19.27 per BOE) in the fourth quarter of 2013 and $8.6 million ($22.83 per BOE) in the first quarter of 2013. The decrease in the amount of depletion and depreciation for the first quarter of 2014 compared to the three months ended March 31, 2013 was due to the asset sales in the fourth quarter of 2013 and lower overall production volumes. Proved plus probable reserves volumes are included in the determination of depletion expense.

Impairment losses

At March 31, 2014, there were no indicators of impairment or reversals of impairment in the Company's CGUs; thus, no impairment test or reversal of impairment calculation was performed.

General and administrative expenses

As detailed at the end of this MD&A, general and administrative (cash) ("G&A (cash)") expenses is a term that does not have any standardized meaning under GAAP. Refer to the section entitled "Non-GAAP Measures" found at the end of this MD&A.

G&A (cash) expenses were $1.9 million ($6.98 per BOE) in the first quarter of 2014 compared to $1.5 million ($6.54 per BOE) for the fourth quarter of 2013 and $2.1 million ($5.45 per BOE) for the first quarter of 2013. G&A (cash) expenses were higher than the fourth quarter of 2013 due to the timing of bonus payments to staff but were lower than the first quarter of 2013 due to lower overall staffing levels. In addition, overhead recoveries are lower in the first quarter of 2014 due to the asset sales in the fourth quarter of 2013. Capitalized general and administrative costs consist of salaries, benefits and office rent associated with staff involved in capital activities.

The following table is a reconciliation of the Company's G&A (cash) expenses to general and administrative expenses:

Three months ended March 31 (thousands of dollars)	2014	2013
Gross G&A (cash) expenses	$2,459	$2,764
Overhead recoveries	(145)	(241)
Capitalized	(455)	(468)
Net G&A (cash) expenses(1)	$1,859	$2,055
Net share-based compensation	82	197
General and administrative expenses	$1,941	$2,252
G&A (cash) expenses ($/BOE)(1)	$6.98	$5.45
% Capitalized	19%	17%

1. General and administrative (cash) expenses is considered a non-GAAP measure. Refer to the section entitled "Non-GAAP Measures" at the end of this MD&A.

Subsequent to March 31, 2014, the Company entered into an agreement to lease new office space at a cost of approximately two-thirds of renewing at its existing premises. The agreement is effective for July 2014 and is subject to the completion of certain customary documentation.

Share-based compensation

Share-based compensation costs were $0.1 million ($0.1 million net of amounts capitalized) for the first quarter of 2014 and $0.1 million for the fourth quarter of 2013 (nil net of amounts capitalized) versus $0.3 million ($0.2 million net of amounts capitalized) in the first quarter of 2013.

Finance expenses

Finance expenses were $2.6 million for the first quarter of 2014, compared to $2.9 million for the fourth quarter of 2013 and $3.3 million in the first quarter of 2013. The decrease in finance expenses from the first quarter of 2013 is the result of lower interest and other financing charges associated with bank credit facilities. Proceeds from the disposition of assets in the fourth quarter of 2013 were used to repay bank debt, and the Company has had no outstanding bank loans since October 2013. Interest expense on credit facilities in the first quarter of 2014 includes stand-by and other fees associated with maintaining the existing bank line of $28 million.

Three months ended March 31 (thousands of dollars)	2014	2013
Interest and accretion on convertible debentures	$2,366	$2,295
Interest expense on credit facilities and other	81	791
Accretion on decommissioning obligations	192	188
Finance expenses	$2,639	$3,274

Decommissioning obligations

The decommissioning liability at March 31, 2014 was lower than at December 31, 2013 due to the disposition of certain natural gas properties in the first quarter of 2014 that carried $3.1 million of decommissioning obligations at December 31, 2013.

Accretion expense was $0.2 million in the first quarter of 2014, provisions incurred were $0.4 million and actual expenditures were $0.2 million.

The risk-free discount rates used by the Company to measure the obligations at March 31, 2014 were between 1.0% and 3.3% (December 31, 2013 - 1.1% to 3.2%) depending on the timelines to reclamation and changed from the start of the year as a result of changes in the Canadian bond market.

Income taxes

The Company has recognized a deferred tax asset in the amount of $2.0 million as at March 31, 2014 and December 31, 2013. No additional deferred tax assets were recognized during the first quarter of 2014. The Company has approximately $365 million of tax pools at March 31, 2014.

Funds from operations

As detailed at the end of this MD&A, "funds from operations" is a term that does not have any standardized meaning under GAAP. Funds from operations is calculated as cash flow from operating activities before changes in non-cash working capital and decommissioning obligations incurred. Refer to the section entitled "Additional GAAP Measures" found at the end of this MD&A.

The following table is a reconciliation of the Company's cash flow from operating activities to funds from operations:

Three months ended March 31 (thousands of dollars)	2014	2013
Cash from operating activities	$2,375	$5,171
Changes in non-cash working capital	2,982	239
Decommissioning expenditures	181	76
Funds from operations	$5,538	$5,486

As expected, following the asset dispositions, funds from operations were a negative outflow of $0.3 million in the fourth quarter of 2013. Due to the impact of higher production resulting from the winter drilling program, and higher commodity prices during the first quarter of 2014, funds from operations were $5.5 million ($0.03 per share) in the first quarter of 2014 versus $5.5 million ($0.03 per share) in the first quarter of 2013.

Earnings

The Company reported earnings of $0.5 million in the first quarter of 2014 compared to a loss of $2.4 million in the fourth quarter of 2013 and a loss of $5.1 million for the first quarter of 2013. Earnings included a gain on sale of property, plant and equipment of $2.0 million in the first quarter of 2014, compared to $1.9 million in the fourth quarter of 2013 and almost nil in the first quarter of 2013. An unrealized loss on derivative contracts of $0.5 million was recorded in the first quarter of 2014, compared to a $0.9 million gain in the fourth quarter of 2013 and $1.1 million loss in the first quarter of 2013.

CAPITAL EXPENDITURES

The Company invested $16.0 million in capital expenditures net of minor property dispositions in first quarter of 2014. The breakdown of expenditures is shown below:

Three months ended March 31 (thousands of dollars)	2014	2013
Land, geological and geophysical costs	$740	$47
Acquisitions	378	-
Drilling, completion and recompletion	10,970	5,324
Facilities and well equipment	3,528	1,830
Capitalized G&A	455	468
	$16,071	$7,669
Change in compressor and other equipment inventory	-	(14)
Office equipment and furniture	11	7
Proceeds on disposition	(50)	-
Total net capital expenditures	$16,032	$7,662

Drilling statistics are shown below:

Three months ended March 31	2014		2013	
	Gross	Net	Gross	Net
Oil	4	4.0	2	1.8
Gas	-	-	-	-
Dry	-	-	-	-
Total	4	4.0	2	1.8
Success rate	100%	100%	100%	100%

The Company completed its winter drilling program with an additional 4 gross (4.0 net capital, 4.0 net revenue) wells drilled during the first quarter of 2014. In the fourth quarter of 2013, the Company drilled 3 gross (3.0 net capital) Cardium horizontal wells.

On February 28, 2014, the Company closed a transaction whereby it disposed of 107 wellbores, 31 compressor stations and 880 Mcfd of forecasted 2014 shallow gas production. This non-operated property had generated negative cash flow in the past two years and was expected to have negative cash flow in 2014 if not sold. The lands had no further development potential.

Subsequent to March 31, 2014, the Company closed or signed letters of intent for $1.1 million in property acquisitions and $0.9 million in property dispositions, largely for drilling prospects on undeveloped land.

RESERVES

Subsequent to March 31, 2014, GLJ Petroleum Consultants ("GLJ"), an independent evaluator, completed a modified corporate look-ahead analysis of the Company's reserves (the "GLJ Interim Report"). The previous 2013 year end evaluation has been updated to an April 30, 2014 effective date, utilizing GLJ's April 1, 2014 price deck and a modified "look ahead" analysis approach. Under this approach, all properties, with the exception of the Edmonton Sands and Willesden Green properties, were mechanically looked-ahead from the original December 31, 2013 effective date (which utilized the GLJ January 1, 2014 price deck) without any adjustments for differences between actual production and GLJ forecast production or financial operating conditions. The Edmonton Sands properties were also mechanically looked-ahead but adjustments were made to the production forecasts to match actual production associated with the first quarter 2014 re-activation of several wells within these properties. The Willesden Green property evaluation was updated to include the property acquisitions and farm-in completed as of April 30, 2014. In addition to including reserves for the acquired lands, several existing reserves entities were converted from a non-producing to a producing category and reserves were added for certain drilled locations that previously had not been booked in the 2013 year end reserves report. The report was prepared for the Company for the purpose of providing a corporate update. The reserves definitions used in preparing the GLJ Interim Report are those contained in the Canadian Oil and Gas Evaluation Handbook. This is not a year end reserves report.

At April 30, 2014, the Company had 3,811 MBOE PDP reserves (33% oil and NGL), 5,472 MBOE TP reserves (36% oil and NGL) and 9,583 MBOE P&P reserves (43% oil and NGL). The GLJ price forecast used in the evaluation is shown below.

The increased reserves in the GLJ Interim Report reflect the impact of the winter drilling program, higher commodity price forecasts, and additional drilling locations associated with recent property acquisitions. The Cardium formation represents approximately 47%, 51% and 63% respectively of PDP, TP and P&P total BOE reserves volumes and 79%, 80% and 82% respectively of the total Company PDP, TP and P&P NPV 10 value.

SUMMARY OF GROSS WORKING INTEREST OIL AND GAS RESERVES (1)

April 30, 2014 December 31, 2013
Oil
(Mbbls) Natural
Gas
Liquids
(Mbbls) Natural
Gas(2)
(MMcf) Total
BOE(3)
(MBOE) Before
tax NPV
10%(4)
($M) Oil
(Mbbls) Natural
Gas
Liquids
(Mbbls) Natural
Gas(2)
(MMcf) Total
BOE(3)
(MBOE) Before
tax NPV
10%(4)
($M)
Proved developed producing
1,020
246
15,269
3,811
63,375 792 216 14,639
Proved developed non-producing
53
34
4,176
784
6,660 128 25 3,683
Proved undeveloped
551
61
1,598
878
11,062 688 72 2,015
Total proved 1,624 341
21,043 5,472 81,097
1,608 313 20,336
5,311 61,608
Probable 1,845 302
11,786 4,111 51,716
1,541 252 10,307
3,512 38,705
Total proved plus probable
3,469
643
32,829
9,583
132,813 3,150 565 30,642

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.

3. Barrels of oil equivalent ("BOE") may be misleading, particularly if used in isolation. Refer to the section entitled "Conversion Measures" at the end of this MD&A.

4. The estimated future annual cash flows determined by the independent reserves evaluators include

assumptions and estimates related to future revenues, royalties, other items of income, operating costs, net capital investments and well abandonment costs for all wells with reserves at the property level. Additional abandonment costs associated with non-reserves wells, lease reclamation costs and facility abandonment and reclamation expenses have not been included in the analysis. 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. Refer to the Company's Annual Information Form for a more complete description of the determination of the reserves values.

SUMMARY OF PRICING AND INFLATION RATE ASSUMPTIONS

As at April 1, 2014
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)
2014 (Q2-Q4)	97.50	102.78	4.64	56.5				0.900
2015	97.50	102.78	4.50	56.53	80.17	113.06	2.0	0.900
2016	97.50	105.56	4.75	58.06	82.33	112.94	2.0	0.900
2017	97.50	105.56	5.00	58.06	82.33	112.94	2.0	0.900
2018	97.50	105.56	5.25	58.06	82.33	112.94	2.0	0.900
2019	97.50	105.56	5.50	58.06	82.33	112.94	2.0	0.900
2020	98.54	106.37	5.63	58.50	82.97	113.81	2.0	0.900
2021	100.51	108.49	5.74	59.67	84.62	116.08	2.0	0.900
2022	102.52	110.66	5.85	60.86	86.31	118.40	2.0	0.900
2023	104.57	112.87	5.97	62.08	88.04	120.77	2.0	0.900
Thereafter 2%								

SHARE INFORMATION

The Company's shares have been listed on the Toronto Stock Exchange since September 7, 2005 under the symbol "AXL". As of May 12, 2014, there were 172.5 million common shares outstanding, 15.2 million stock options outstanding, $50.0 million principal amount of convertible debentures which are convertible into common shares at a conversion price of $1.55 per common share and $46.0 million principal amount of convertible debentures which are convertible into common shares at a conversion price of $1.70 per common share. During the first quarter of 2013 and 2014, no common shares were issued through the exercise of employee stock options.

SHARE PRICE ON TSX

Three months ended March 31	2014	2013
High	$0.28	$0.25
Low	$0.13	$0.17
Close	$0.24	$0.19
Volume	19,978,551	6,360,434
Shares outstanding at March 31	172,549,701	172,549,701
Market capitalization at March 31	$41,411,928	$31,921,695

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 12.5 million common shares traded on these alternative exchanges in the three months ended March 31, 2014 (March 31, 2013 - 3.4 million). Including these exchanges, an average of 523,223 common shares traded per day in the three months ended March 31, 2014 (March 31, 2013 - 160,366), representing a quarterly turnover ratio of 19% (March 31, 2013 - 6%).

LIQUIDITY AND CAPITAL RESOURCES

At March 31, 2014, the Company had no outstanding bank loans, convertible debentures of $96.0 million (principal) and a working capital deficiency of $1.0 million. Proceeds from property dispositions in the fourth quarter of 2013 were used to repay the credit facilities, and the excess cash will be used to help fund the 2013/2014 drilling program. The following table shows the changes in bank loans plus working capital (deficiency):

Three months ended (thousands of dollars)	March 31, 2014	December 31, 2013
Bank loans plus working capital (deficiency), beginning of period	$9,682	$16,499
Funds from operations	5,538	(306)
Net proceeds on disposition of assets (capital expenditures)	(16,032)	71,972
Change in assets held for sale included in working capital (deficiency)	-	(84,196)
Change in decommissioning obligations held for sale included in working capital (deficiency)	-	6,308
Decommissioning expenditures	(181)	(595)
Bank loans plus working capital (deficiency), end of period	$(993)	$9,682
Bank loans, end of period	$-	$-
Working capital (deficiency), end of period	(993)	9,682
Bank loans plus working capital (deficiency), end of period	$(993)	$9,682

The continued development of the Company's oil and gas assets is dependent on the ability of the Company to secure sufficient funds through operations, bank facilities and other sources. Short-term capital is required to finance accounts receivable and other similar short-term assets, while the acquisition and development of oil and natural gas properties requires larger amounts of long-term capital.

At March 31, 2014, the Company had a $28 million extendible committed term bank facility with a Canadian bank under which $27.9 million of credit was available with $0.1 million in letters of credit outstanding that reduce the amount of available credit. Under the agreement, advances can be drawn in Canadian funds and bear interest at the bank's prime lending rate or guaranteed notes discount rates plus applicable margins. These margins vary from 2.25% to 3.6% depending on the borrowing option used.

Anderson will prudently use its bank loan facility to finance its operations as required.

Loans are secured by general security agreements providing security interests over all assets and by guarantees of material subsidiaries.

Under the terms of the bank facility, the Company has provided a financial covenant that the amount of its current liabilities shall not exceed the sum of its current assets and the undrawn availability under the facility at the end of each fiscal quarter. Unrealized gains (losses) on derivative contracts are excluded from the above amounts. The Company was in compliance with this financial covenant as at March 31, 2014.

Subsequent to March 31, 2014, the Company agreed to an increase in its bank facility from $28 million to $31 million, subject to customary closing conditions. The term date was extended to May 30, 2015. If this revolving operating loan facility is not extended at May 30, 2015, any outstanding advances would become repayable one year later on May 30, 2016.

As of today's date, the Company is not drawn on its bank facility.

OFF-BALANCE SHEET ARRANGEMENTS

The Company had no guarantees or off-balance sheet arrangements other than as described either below or in the management's discussion and analysis for the year ended December 31, 2013 under "Contractual Obligations."

CONTRACTUAL OBLIGATIONS

The Company enters into various contractual obligations in the course of conducting its operations. There were no material changes to the contractual obligations that were discussed in management's discussion and analysis for the year ended December 31, 2013 other than the following:

- Cardium Horizontal Well Program (Oil) - At March 31, 2014, the Company had an obligation under a farm-in agreement to drill one Cardium oil well prior to October 31, 2014 to earn a working interest in the farm-out lands. The capital commitment associated with the well is $2.5 million.

- Office Lease - Subsequent to March 31, 2014, the Company entered into an agreement to lease office space at a cost of approximately $0.4 million per year from July 1, 2014 to October 30, 2018, subject to customary closing conditions.

CRITICAL ACCOUNTING ESTIMATES

The preparation of financial statements requires the Company to make estimates, assumptions and judgements in the application of IFRS that have a significant impact on the financial results of the Company. Actual results could differ from estimated amounts, and those differences may be material. A comprehensive discussion of the Company's significant critical accounting estimates is contained in the MD&A and the audited consolidated financial statements for the year ended December 31, 2013.

NEW AND PENDING ACCOUNTING STANDARDS

Standards that are issued and that the Company reasonably expects to be applicable at a future date are listed below.

IFRS 9 Financial Instruments. In November 2009, the IASB issued IFRS 9, Financial Instruments ("IFRS 9 (2009)"), and in October 2010, the IASB published amendments to IFRS 9 ("IFRS 9 (2010)"). In November 2013, the IASB issued a new general hedge accounting standard, which forms part of IFRS 9 Financial Instruments ("IFRS 9 (2013)").

IFRS 9 (2013) includes a new general hedge accounting standard which will align hedge accounting more closely with risk management. This new standard does not fundamentally change the types of hedging relationships or the requirement to measure and recognize ineffectiveness; however, it will provide more hedging strategies that are used for risk management to qualify for hedge accounting and introduce more judgment to assess the effectiveness of a hedging relationship.

The amendments to IFRS 9 are applied retrospectively for annual periods beginning on or after January 1, 2018, with early adoption allowed. The Company is currently assessing the effect on its financial statements.

CHANGES IN ACCOUNTING POLICIES

On January 1, 2014, the Company adopted the following new IFRS standards and amendments in accordance with the transitional provisions of each standard. The adoption of these standards did not have a material impact on the Company's financial statements. A brief description of each new standard follows below:

i. Offsetting Financial Assets and Financial Liabilities (Amendments to IAS 32 Financial Instruments: Presentation ("IAS 32"). The amendments to IAS 32 clarify the requirements for offsetting financial instruments such as the accounts receivable and payable related to the Company's commodity contracts. The amendments clarify when an entity has a legally enforceable right to offset and certain other requirements that are necessary to present a net financial asset or liability.

ii. Levies ("IFRIC 21"). In May 2013, the International Accounting Standards Board ("IASB") issued IFRIC 21 Levies which was developed by the IFRS Interpretations Committee ("IFRIC"). IFRIC 21 clarifies that an entity recognizes a liability for a levy when the activity that triggers payment, as identified by the relevant legislation, occurs. The interpretation also clarifies that no liability should be recognized before the specified minimum threshold to trigger that levy is reached.

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 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 January 1, 2014 and ending on March 31, 2014 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.

It should be noted that 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 recently strengthened due to weather-related changes to demand; however, the concern over increasing U.S. gas production, driven primarily by the U.S. shale gas plays, continues to depress the natural gas futures market. Oil prices continue to remain volatile as they are a geopolitical commodity, affected by concerns about global economic markets and continued instability in oil producing countries. Differentials between WTI oil prices and prices received in Alberta are 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 and maintain drilling licences and other regulatory approvals, ability to obtain equipment, expiration of licences and leases, competition from other producers, third-party transportation and processing disruption issues, 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 certain Canadian securities regulatory authorities on SEDAR at www.sedar.com.

The Company makes substantial capital expenditures for the acquisition, exploration, development and production of oil and natural gas reserves. 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 and professional staff, following sound operating practices and using capital prudently. The Company generates its exploration and development 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 endeavours 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, transportation 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, impact the Company's ability to get its product to market, 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 in, amongst other things, suspension or revocation of necessary licenses and authorizations, civil liability for pollution damage, and the imposition of material fines and penalties.

STRATEGY

The Company's business plan is to pursue growth of its asset base and cash flow, and increase its financial flexibility to meet its obligations when they become due. Coming out of the strategic alternatives process, the Company is smaller in terms of production, has cash in the bank and an unused bank operating line. Its convertible debentures mature in 2016 and 2017.

With the bank debt issues resolved, Anderson intends to focus on rebuilding its asset base by drilling Cardium and Mannville horizontal light oil wells, and growing its Cardium and Mannville horizontal oil drilling inventory in the Willesden Green, West Pembina and Buck Lake areas. In its first full quarter since completion of the strategic alternatives process, the Company has shown progress on all fronts, with increasing oil production, cash flow and reserves. The longer-term debenture maturities give the Company time to rebuild its asset base. By resuming a drilling program and controlling the infrastructure in its Cardium oil properties where feasible, the Company should be able to increase oil production and operating netbacks. A strategy of increasing oil assets, production and cash flow should also support a higher borrowing base over time.

Anderson will continue to focus on reducing average well payouts. The goal is to have Cardium wells pay out in approximately one year, on average, by continuing to improve the profitability of these operations. The Company believes this goal can be achieved by continuing to implement new approaches in Cardium horizontal drilling and completion technologies, and by keeping costs as low as possible.

Recent technological changes include repositioning the trajectory of the horizontal well within the Cardium zone to maximize frac effectiveness, and using dissolvable frac balls. In 2014, the Company plans to drill its first long-reach horizontal oil well that is expected to traverse up to 3,000 metres of horizontal Cardium net pay. It is anticipated that long-reach horizontal wells will access Cardium reserves in two sections of land as opposed to the current one section of land per horizontal well. There is a capital cost benefit to drilling an extended reach well over two sections as compared to two wells traversing one section of land each. There is also a reserves benefit with longer horizontal wells due to additional reservoir contact.

Where it can, the Company strives to operate its own oil and gas infrastructure and attract third parties to utilize this infrastructure on a processing fee basis in order to reduce overall operating costs. Currently, the Company operates over 90% of its production and all of its current drilling operations.

Anderson is developing new light oil horizontal plays on its existing acreage in the Mannville and Belly River and is planning to drill one of these plays in 2014.

The Company currently has no plans to dispose of its Cardium oil assets. In addition, the Company currently has no plans to buy back common shares or convertible debentures with normal course issuer bids. The Company's plan is to continue to grow its asset base by investing in its light oil drilling opportunities,

Anderson will continue to look for ways to optimize, rationalize, consolidate and improve the profitability of its shallow gas business. In the fourth quarter of 2013 and the first quarter of 2014, the Company disposed of unprofitable shallow gas assets. The Company's remaining shallow gas properties are profitable at current natural gas prices. The Company is not planning any significant new investments in the shallow gas business, and may dispose of some or all of its remaining shallow gas assets.

For 2014, the Company estimates that oil and NGL production will be approximately 36% of total production, and that revenue from oil and NGL will be approximately 66% of total revenue. The Company expects the percentage contribution of oil and NGL to total revenue to grow, and estimates that its production will be balanced between natural gas, and oil and NGL by the end of 2015.

2014 CAPITAL BUDGET

The Board of Directors has approved a 2014 capital budget of $46 million. Sixty-eight percent of the budget is directed at drilling and completion expenditures to drill 12 net Cardium and Mannville horizontal light oil drilling prospects. Twenty-four percent of the expenditures are directed at equipping, tie-in and facility expenditures and the remaining funds are directed at land, abandonments and capitalized G&A expenditures.

With this capital program, the annual production guidance for 2014 has increased to approximately 3,200 BOED (36% oil and NGL) up from the guidance provided by Company in its March 31, 2014 press release (2,600 BOED, 33% oil and NGL). The Company estimates 2014 exit production to be approximately 3,700 BOED (42% oil and NGL).

In addition to the seven well 2013/2014 Cardium winter program, the Company is planning to drill 15 gross (12.6 net) Cardium and Mannville light oil horizontal wells from the second quarter of 2014 to spring breakup 2015. The Company continues to evaluate farm-in and property acquisitions in its Cardium and Mannville light oil focus areas. Should the Company add additional farm-in commitments, it will substitute those commitments into its 2014 capital program and defer budgeted locations until 2015.

QUARTERLY INFORMATION

The following table provides financial and operating results for the last eight quarters. Commodity prices remained volatile, affecting funds from operations and earnings throughout those quarters. The Company curtailed its drilling program in 2012, drilling a modest number of wells in 4 of the past 8 quarters, as shown in the following table:

Quarter	Gross wells	Net wells - capital	Net wells - revenue
Q1 2014	4	4.0	4.0
Q4 2013	3	3.0	3.0
Q1 2013	2	1.8	1.5
Q4 2012	4	4.0	2.8

The impact of the sale of properties in 2012 and in the last quarter of 2013, as well as natural production declines, contributed to lower production volumes and revenues in 2012 and 2013. Production improved significantly in the first quarter of 2014 relative to the last quarter of 2013 due to the Cardium horizontal well winter drilling program during the last quarter of 2013 and the first quarter of 2014.

Earnings were affected in the second quarter of 2012 by impairments in the value of natural gas properties, whereas earnings in the second quarter of 2013 were affected by the tax expense related to derecognizing the deferred tax asset. Earnings in the third quarter of 2013 were impacted by the impairment on the assets held for sale.

Bank loan balances fluctuated in response to the capital spending programs related to Cardium oil development through 2012 and into 2013. Bank loans were reduced by the proceeds from the sale of assets and from cash from operating activities in 2012 and 2013.

SELECTED QUARTERLY INFORMATION

($ amounts in thousands, except per share amounts and prices)	Q1 2014	Q4 2013	Q3 2013	Q2 2013
Revenue, net of royalties	$13,195	$7,288	$11,949	$14,345
Funds from operations(1)	$5,538	$(306)	$1,408	$4,701
Funds from operations per share, basic and diluted(1)	$0.03	$-	$0.01	$0.03
Adjusted earnings (loss) before taxes(2)	$544	$(2,745)	$(5,856)	$(3,672)
Adjusted earnings (loss) before taxes per share, basic and diluted(2)	$-	$(0.02)	$(0.03)	$(0.02)
Earnings (loss)	$544	$(2,445)	$(48,737)	$(49,306)
Earnings (loss) per share, basic and diluted	$-	$(0.01)	$(0.28)	$(0.29)
Capital expenditures (net of proceeds on dispositions)	$16,032	$(71,972)	$229	$186
Cash from operating activities	$2,375	$(230)	$1,626	$3,953
Bank loans	$-	$-	$53,945	$53,892
Daily sales				
Oil (bpd)	969	537	983	
NGL (bpd)	170	166	280	
Natural gas (Mcfd)	10,920	10,467		
BOE (BOED)	2,958	2,448	3,44	
Average prices				
Oil ($/bbl)(4)	$97.36	$84.26	$100.81	$89.76
NGL ($/bbl)	$69.13	$61.60	$52.97	$48.73
Natural gas ($/Mcf)(4)	$5.01	$3.19		

$2.27 $3.33
BOE ($/BOE)(3)(4) $54.54 $36.49
$41.87 $43.66
Q1 2013 Q4 2012
Q3 2012 Q2 2012
Revenue, net of royalties $15,268
13,796 $15,284 $18,290
Funds from operations(1) $5,486
5,694 $5,725 $7,606
Funds from operations per share, basic and diluted(1) $0.03
0.03
$0.03 $0.04
Adjusted earnings (loss) before taxes(2)
$(5,113) (11,799)
$173 $(2,369)
Adjusted earnings (loss) before taxes per share,
basic and diluted(2) $(0.03) (0.07)
$- $(0.01)
Earnings (loss) $(5,113) (8,895)
$94 $(16,828)
Earnings (loss) per share, basic and diluted
$(0.03) (0.05) $- $(0.10)
Capital expenditures (net of proceeds on dispositions) $7,662
(26,880)
$(28,986) $4,786
Cash from operating activities
$5,171 6,976
$5,845 $7,712
Bank loans $55,141 48,094
$88,922 $119,686
Daily sales
Oil (bpd) 1,529
1,135 1,274
1,669
NGL (bpd) 203
338 576
750
Natural gas (Mcfd) 14,759 18,159
26,438
BOE (BOED) 4,191
4,500 5,770
6,825
Average prices
Oil ($/bbl)(4) $84.83 79.73
$80.44 $81.58
NGL ($/bbl) $61.77 52.02
$51.59 $54.38
Natural gas ($/Mcf) $2.94
3.16 $2.24 $1.72
BOE ($/BOE)(3)(4) $44.70
36.89 $32.05 $32.70

1. Funds from operations and funds from operations per share do not have standardized meanings prescribed by GAAP. Refer to the sections entitled "Funds from Operations" and "Additional GAAP Measures" at the end of this MD&A.

2. Adjusted earnings (loss) before taxes, adjusted earnings (loss) before taxes per share and operating netback per BOE are considered non-GAAP measures. Refer to the section entitled "Non-GAAP Measures" at the end of this MD&A.

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

4. Excludes realized and unrealized hedging gains (losses) on derivative contracts as follows: Q1 2014 - ($0.4 million) and ($0.5 million), respectively; Q4 2013 - ($0.9 million) and $0.9 million, respectively; Q3 2013 - $(1.6 million) and $0.5 million, respectively; Q2 2013 - ($0.7 million) and $0.6 million, respectively; Q1 2013 - ($0.6 million) and ($1.1 million), respectively; Q4 2012 - $2.2 million and ($2.8 million), respectively; Q3 2012 - $1.7 million and ($2.7 million), respectively; and Q2 2012 - $1.3 million and $4.7 million, respectively.

CONVERSION MEASURES

Production volumes and reserves are commonly expressed on a BOE basis whereby natural gas volumes are converted at the ratio of 6 thousand cubic feet to 1 barrel of oil. Although 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, BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 Mcf to 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. In recent years, the value ratio based on the price of crude oil as compared to natural gas has been significantly higher than the energy equivalency of 6:1, and utilizing a conversion of natural gas volumes on a 6:1 basis may be misleading as an indication of value.

NON-GAAP MEASURES

Included in this document are references to the terms "adjusted earnings (loss) before taxes," "adjusted earnings (loss) before taxes per share," "operating netback," "operating netback per share" and "general and administrative (cash) expenses". Management believes these measures are helpful supplementary measures of financial performance and provide users with information that is commonly used by other oil and gas companies. These terms do not have any standardized meaning prescribed by GAAP and should not be considered an alternative to, or more meaningful than, "earnings (loss) before taxes" or "earnings (loss) and comprehensive income (loss)" as determined in accordance with GAAP as a measure of the Company's performance.

Adjusted earnings (loss) before taxes is calculated as earnings (loss) before taxes per the Consolidated Statement of Operations and Comprehensive Income (Loss), excluding impairment loss, and provides supplemental information on the Company's before income tax performance, excluding the impact of impairment losses. Operating netback is calculated as oil and gas sales plus applicable realized gains/losses on derivative contracts less royalties, operating expenses and transportation expenses and is a measure of the profitability of operations before administrative, financing and other non-cash items.

General and administrative (cash) expenses are general and administrative costs excluding non-cash share-based compensation and provides supplemental information regarding the impact of general and administrative costs on the Company's cash flows.

ADDITIONAL GAAP MEASURES

Funds from operations

This document, including the accompanying financial statements, contain the term "funds from operations" which does not have any standardized meaning prescribed by GAAP and should not be considered an alternative to, or more meaningful than, "cash flow from operating activities" as determined in accordance with GAAP as a measure of the Company's performance. Funds from operations or funds from operations per share may not be comparable with the calculation of similar measures for other entities. Funds from operations as used in this report represent cash from operating activities before changes in non-cash working capital and decommissioning expenditures. See "Funds from Operations" under "Review of Financial Results" for details of this calculation. Management believes that funds from operations represent both an indicator of the Company's performance and a funding source for ongoing operations.

Other additional GAAP measures

This document including the accompanying financial statements also contain the terms "working capital or working capital (deficiency)," "net debt before convertible debentures," "total net debt" and "total capitalization" which do not have any standardized meaning prescribed by GAAP and may not be comparable with the calculation of similar measures for other entities.

Working capital is defined as the difference between current assets and current liabilities. Working capital (deficiency) is the term used when the difference between current assets and current liabilities is a negative number. The unrealized gains on derivative contracts are excluded from current assets and unrealized losses on derivative contracts are excluded from current liabilities in the calculation of working capital and working capital (deficiency). Working capital and working capital (deficiency) represent operating liquidity available to the business and are included in the definition of the additional GAAP term "net debt."

Net debt before convertible debentures is calculated as long-term debt plus working capital or working capital (deficiency). Total net debt is calculated as net debt before convertible debentures plus the liability component of convertible debentures. Management believes these measures are useful supplementary measures of the total amount of current and long-term debt. Total capitalization is calculated as total net debt plus shareholders' equity. Management believes this measure is a useful supplementary measure of the Company's managed capital.

FORWARD-LOOKING STATEMENTS

Certain statements in this news release including, without limitation, management's assessment of future plans and operations; benefits and valuation of the development prospects described herein; number of locations in drilling inventory and wells to be drilled; timing and location of drilling and tie-in of wells and the costs thereof; productive capacity of the wells; timing and construction of facilities; expected production rates; improved production from slick water fracture technology; 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; expectations related to future operating netbacks; programs to optimize, rationalize, consolidate and improve profitability of assets; factors on which the continued development of the Company's oil and gas assets are dependent; commodity price outlook; and general economic outlook may constitute "forward-looking information" within the meaning of applicable securities laws and necessarily involve risks and assumptions made by management of the Company including, without limitation, risks associated with oil and gas exploration, development, exploitation, production, marketing and transportation; loss of markets; volatility of commodity prices; currency fluctuations; imprecision of reserves estimates; environmental risks; competition from other producers; inability to retain drilling rigs and other services; adequate weather to conduct operations; sufficiency of budgeted capital, operating and other costs to carry out planned activities; wells not performing as expected; incorrect assessment of the value of acquisitions and farm-ins; failure to realize the anticipated benefits of acquisitions and farm-ins; inability to complete property dispositions or to complete them at anticipated values; 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 securities regulatory authorities and may be accessed through the SEDAR website (www.sedar.com) or at Anderson's website (www.andersonenergy.ca).

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

ANDERSON ENERGY LTD.

Consolidated Statements of Financial Position

(Stated in thousands of dollars)

(Unaudited)	March 31, 2014	December 31, 2013
ASSETS		
Current assets:		
Cash and cash equivalents	$12,364	$25,111
Accounts receivables and accruals	10,228	6,702
Prepaid expenses and deposits	941	1,286
Total current assets	23,533	33,099
Deferred tax asset	2,000	2,000
Property, plant and equipment (note 3)	145,014	135
Total assets	$170,547	$171,077
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable and accruals	$24,526	$23,417
Unrealized loss on derivative contracts (note 11)		610
Total current liabilities	25,136	23,563
Convertible debentures	89,517	88,922
Decommissioning obligations (note 5)	27,054	30,41
Total liabilities	141,707	142,898
Shareholders' equity:		
Share capital (note 6)	171,460	171,460
Equity component of convertible debentures	5,019	5
Contributed surplus	11,355	11,238
Deficit	(158,994)	(159,538)
Total shareholders' equity	28,840	28,179
Commitments and contingencies (note 12)		
Subsequent events (notes 4, 11, 12)		
Total liabilities and shareholders' equity	$170,547	$171,077

See accompanying notes to the condensed interim consolidated financial statements.

ANDERSON ENERGY LTD.

Consolidated Statements of Operations and Comprehensive Income (Loss)

THREE MONTHS ENDED MARCH 31, 2014 AND 2013

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

(Unaudited)	2014	2013
Oil and gas sales	$14,522	$16,863
Royalties	(1,327)	(1,595)
Revenue, net of royalties	13,195	15,268
Other losses (note 8)	(871)	(1,657)
Total revenue, net of royalties and other losses	12,324	
Operating expenses	3,536	4,503
Transportation expenses	62	77
Depletion and depreciation (note 3)	5,653	8,613
(Gain) loss on sale of property, plant and equipment (note 3)	(1,992)	6
General and administrative expenses	1,941	2,252
Earnings (loss) from operating activities	3,124	(1
Finance income (note 9)	59	1
Finance expenses (note 9)	(2,639)	(3,274)
Net finance expenses	(2,580)	(3,273)
Earnings (loss) and comprehensive income (loss) for the period	544	(5,113)
Basic and diluted earnings (loss) per share (note 7)	$-	$(0.03)

See accompanying notes to the condensed interim consolidated financial statements.

ANDERSON ENERGY LTD.

Consolidated Statements of Changes in Shareholders' Equity

THREE MONTHS ENDED MARCH 31, 2014 AND 2013
(Stated in thousands of dollars, except number of common shares)
(Unaudited)

	Number of common shares	Share capital	Equity component of convertible debentures	Contributed surplus	Deficit	Total shareholders' equity
Balance at December 31, 2012	172,549,701	$171,460	$5,019	$10,418	$ (53,937)	$132,960
Share-based payments	-	-	-	263	-	
Loss for the period	-	-	-	-	(5,113)	(5,113)
Balance at March 31, 2013	172,549,701	$171,460	$5,019	$10,681	$(59,050)	$128,110
Balance at December 31, 2013	172,549,701	$171,460	$5,019	$11,238	$(159,538)	$28,179
Share-based payments	-	-	-	117	-	
Earnings for the period	-	-	-	-	544	
Balance at March 31, 2014	172,549,701	$171,460	$5,019	$11,355	$(158,994)	$28,840

See accompanying notes to the condensed interim consolidated financial statements.

ANDERSON ENERGY LTD.

Consolidated Statements of Cash Flows

THREE MONTHS ENDED MARCH 31, 2014 AND 2013
(Stated in thousands of dollars)

(Unaudited)	2014	2013
CASH PROVIDED BY (USED IN)		
OPERATIONS		
Earnings (loss) for the period	$544	$(5,113)
Adjustments for:		
Unrealized loss on derivative contracts (note 8)	464	
(Gain) loss on sale of property, plant and equipment (note 3)	(1,992)	6
Depletion and depreciation (note 3)	5,653	8,613
Share-based payments	82	197
Accretion on decommissioning obligations (note 5)	192	188
Accretion on convertible debentures (note 9)	595	5
Decommissioning expenditures (note 5)	(181)	(76)
Changes in non-cash working capital (note 10)	(2,982)	(239)
Net cash provided by operations	2,375	5,171
FINANCING		
Increase in bank loans	-	7,047
Net cash used in financing	-	7,047
INVESTING		
Property, plant and equipment expenditures (note 3)	(16,082)	(7,662)
Proceeds from sale of property, plant and equipment (note 3)	50	-
Changes in non-cash working capital (note 10)	910	
Net cash used in investing	(15,122)	(12,219)
Decrease in cash and cash equivalents	(12,747)	(1)
Cash and cash equivalents, beginning of period	25,111	1
Cash and cash equivalents, end of period	$12,364	$-
Interest received in cash	$84	$1
Interest paid in cash	$(1,879)	$(2,565)

See accompanying notes to the condensed interim consolidated financial statements.

ANDERSON ENERGY LTD.

Notes to the Condensed Interim Consolidated Financial Statements

THREE MONTHS ENDED MARCH 31, 2014 WITH COMPARATIVE FIGURES FOR 2013

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

(Unaudited)

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 2200, 333 - 7th Avenue SW, Calgary, Alberta, Canada, T2P 2Z1.

2. BASIS OF PREPARATION

(a) Statement of compliance:

The condensed interim consolidated financial statements comply with International Accounting Standard 34 Interim Financial Reporting and do not include all of the information required for full annual financial statements.
The condensed interim consolidated financial statements were authorized for issuance by the Board of Directors on May 12, 2014.

(b) Accounting policies, judgments, estimates and disclosures:

In preparing these condensed interim consolidated financial statements, the accounting policies, methods of computation and significant judgements made by management in applying the Company's accounting policies and key sources of estimation uncertainty were the same as those that applied to the audited consolidated financial statements as at and for the years ended December 31, 2013 and 2012 except as disclosed below.

On January 1, 2014, the Company adopted new standards with respect to Offsetting Financial Assets and Financial Liabilities (Amendments to IAS 32 Financial Instruments: Presentation ("IAS 32") and IFRIC 21 Levies ("IFRIC 21"). The amendments to IAS 32 clarify the requirements for offsetting financial instruments such as the amounts receivable and payable related to the Company's commodity contracts. The amendments clarify when an entity has a legally enforceable right to offset and certain other requirements that are necessary to present a net financial asset or liability. IFRIC 21 clarifies that an entity recognizes a liability for a levy when the activity that triggers payment, as identified by the relevant legislation, occurs. The interpretation also clarifies that no liability should be recognized before the specified minimum threshold to trigger that levy is reached. The adoption of these standards had no impact on the amounts recorded in the consolidated financial statements as at January 1, 2014 or on the comparative periods.

The following disclosures are incremental to those included with the annual audited consolidated financial statements. Certain disclosures that are normally required in the notes to the annual audited consolidated financial statements have been condensed or omitted. These condensed interim consolidated financial statements should be read in conjunction with the Company's audited consolidated financial statements and notes thereto for the years ended December 31, 2013 and 2012.

3. PROPERTY, PLANT AND EQUIPMENT

Cost or deemed cost

	Oil and natural gas assets	Other equipment	Total
Balance at December 31, 2012	$593,048	$1,904	$594,952
Additions	8,128	17	8,145
Disposals	(204,757)	-	(204,757)
Balance at December 31, 2013	396,419	1,921	
Additions	15,837	11	15,848
Disposals	(9,580)	-	(9,580)
Balance at March 31, 2014	$402,676	$1,932	$404,608

Accumulated depletion, depreciation and impairment losses

	Oil and natural gas assets	Other equipment	Total
Balance at December 31, 2012	$307,251	$1,527	$ 308,7
Depletion and depreciation for the year	27,805	104	
Impairment loss	44,581	-	44,581
Disposals	(118,906)	-	(118,906)
Balance at December 31, 2013	$260,731	$1,631	$ 262,3
Depletion and depreciation for the period	5,629	24	
Disposals	(8,421)	-	(8,421)
Balance at March 31, 2014	$257,939	$1,655	$259,594

Carrying amounts

	Oil and natural gas assets	Other equipment	Total
At December 31, 2013	$135,688	$290	$135,978
At March 31, 2014	$144,737	$277	$145,014

Capitalized overhead

For the three months ended March 31, 2014, additions to property, plant and equipment included internal overhead costs of $0.5 million (year ended December 31, 2013 - $1.8 million).

Sale of property, plant and equipment

For the three months ended March 31, 2014, the Company sold interests in properties for total consideration of $0.1 million (year ended December 31, 2013 - $80.1 million). Provisions for decommissioning obligations related to assets sold were $3.1 million. A gain on sale of assets of $2.0 million was recorded for the three months ended March 31, 2014.

4. BANK LOANS

At March 31, 2014, the Company has a $28 million extendible committed term bank facility with a Canadian bank. Under the agreement, advances can be drawn in Canadian funds and bear interest at the bank's prime lending rate or guaranteed notes discount rates plus applicable margins. These margins vary from 2.25% to 3.6% depending on the borrowing option used.

The Company had no operating loans outstanding during the three months ended March 31, 2014. The average effective interest rate on advances under the Company's operating loan facilities during the three months ended March 31, 2013 was 5.5%. The Company had $0.1 million in letters of credit outstanding at March 31, 2014 that reduce the amount of credit available to the Company.

Loans are secured by general security agreements providing security interests over all assets and by guarantees of material subsidiaries.

Under the terms of the bank facility, the Company has provided a financial covenant that the amount of its current liabilities shall not exceed the sum of its current assets and the undrawn availability under the facility at the end of each fiscal quarter. Unrealized gains (losses) on derivative contracts and the current portion of any bank debt, convertible debentures and capital leases, if any, are excluded from the above amounts.

Subsequent to March 31, 2014, the Company agreed to an increase its bank facility from $28 million to $31 million, subject to the completion of customary closing conditions. The term date was extended to May 30, 2015. If this revolving operating loan facility is not extended at May 30, 2015, any outstanding advances would become repayable one year later on May 30, 2016.

5. DECOMMISSIONING OBLIGATIONS

	March 31, 2014	December 31, 2013
Balance at January 1	$30,413	$46,467
Provisions incurred	363	438
Total abandonment expenditures	(181)	(971)
Provisions disposed	(3,126)	(7,865)
Change in estimates	(607)	(8,470)
Accretion expense	192	814
Ending balance	$27,054	$30,413

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 $27.1 million as at March 31, 2014 (December 31, 2013 - $30.4 million) based on an undiscounted inflation-adjusted total future liability of $48.5 million (December 31, 2013 - $49.9 million). These payments are expected to be made over the next 30 years with the majority of costs to be incurred between 2016 and 2029. At March 31, 2014, the liability has been calculated using an inflation rate of 2.0% (December 31, 2012 - 2.0%) and discounted using a risk-free rate of 1.0% to 3.3% (December 31, 2013 - 1.1% to 3.2%) depending on the estimated timing of the future obligation.

6. 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 December 31, 2012, December 31, 2013 and March 31, 2014	172,549,701	$171,460

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 10 years and vest equally over a two or three year period starting on the first anniversary date of the grant.

Changes in the number of options outstanding during the period ended March 31, 2014 and the year ended December 31, 2013 are as follows:

	March 31, 2014		December 31, 2013	
	Number of options	Weighted average exercise price	Number of options	Weighted average exercise price
Opening balance	15,413,350	$0.54	14,386,800	$0.75
Granted during the period	15,600	0.14	3,160,100	
Expired during the period	(116,000)	0.77	(1,295,617)	
Forfeited during the period	(106,700)	0.26	(837,933)	
Ending balance	15,206,250	$0.54	15,413,350	$0.54
Exercisable, end of period	7,850,817	$0.79	7,951,817	

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)
$0.13 to $0.20	3,127,000	$0.13	4.6
$0.21 to $0.32	5,027,300	0.31	3.6
$0.33 to $0.50	120,000	0.45	2.6
$0.51 to $0.77	2,379,600	0.70	2.4
$0.78 to $1.17	4,318,350	0.93	0.9
$1.18 to $1.77	141,000	1.21	1.7
$2.68 to $4.00	93,000	4.00	0.2
Total at March 31, 2014	15,206,250	$0. 54	2.8

There were no options exercised in the three months ended March 31 2014 and March 31, 2013.

The fair value of the options was estimated using the Black-Scholes model with the following weighted average inputs for the three months ended March 31, 2014 (there were no options issued during the three months ended March 31, 2013):

This estimated forfeiture rate is adjusted to the actual forfeiture rate when each tranche vests. Share-based compensation of $0.1 million (March 31, 2013 - $0.2 million) was expensed during the three months ended March 31, 2014. In addition, share-based compensation of nil (March 31, 2013 - $0.1 million) was capitalized during the three months ended March 31, 2014.

	March 31, 2014
Fair value at grant date	$0.08
Common share price	$0.14
Exercise price	$0.14
Volatility	67%
Option life	5 years
Dividends	0%
Risk-free interest rate	1.7%
Forfeiture rate	20%

7. EARNINGS (LOSS) PER SHARE

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

	March 31, 2014	March 31, 2013
Earnings (loss) for the period	$544	$(5,113)
Weighted average number of common shares (basic), (in thousands of shares)	172,550	172,550
Basic earnings (loss) per share	$-	$(0.03)
Weighted average number of common shares (diluted), (in thousands of shares)	172,943	172,550
Diluted earnings (loss) per share	$-	$(0.03)

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 three months ended March 31, 2014, 12,030,550 options (March 31, 2013 - 14,143,800 options) and 59,316,889 common shares reserved for convertible debentures (March 31, 2013 - 59,316,889) were excluded from calculating dilutive earnings as they would not have been dilutive.

8. OTHER LOSSES

Other losses include the following:

	March 31, 2014	March 31, 2013
Realized loss on derivative contracts	$(407)	$(586)
Unrealized loss on derivative contracts	(464)	(1,071)
	$(871)	$(1,657)

9. FINANCE INCOME AND EXPENSES

	March 31, 2014	March 31, 2013
Income:		
Interest income on cash equivalents	$55	$1
Other interest income	4	-
Expenses:		
Interest and financing costs on bank loans	(77)	(768)
Interest on convertible debentures	(1,771)	(1,771)
Accretion on convertible debentures	(595)	(524)
Accretion on decommissioning obligations (note 5)	(192)	(1
Other	(4)	(23)
Net finance expenses	$(2,580)	$(3,273)

10. SUPPLEMENTAL CASH FLOW INFORMATION

Changes in non-cash working capital is comprised of:

	March 31, 2014	March 31, 2013
Source (use) of cash		
Accounts receivable and accruals	$(3,526)	$(368)
Prepaid expenses and deposits	345	113
Accounts payable and accruals	1,109	(4,541)
	$(2,072)	$(4,796)
Related to operating activities	$(2,982)	$(239)
Related to financing activities	$-	$-
Related to investing activities	$910	$(4,557)

11. FINANCIAL RISK MANAGEMENT

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

- Level 1 - observable inputs such as quoted prices in active markets;

- Level 2 - inputs, other than the quoted market prices in active markets, which are observable, either directly and/or indirectly; and

- Level 3 - unobservable inputs for the asset or liability in which little or no market data exists, therefore requiring an entity to develop its own assumptions.

The fair value of the derivative contracts used for risk management as shown in the condensed interim consolidated financial statements as at March 31, 2014 and the audited consolidated financial statements as at December 31, 2013 are measured using level 2.

(a) 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.

The following are the contractual maturities of financial liabilities, including associated interest payments on convertible debentures and excluding the impact of netting agreements at March 31, 2014:

Financial Liabilities Less
than
one
year One to
two years Two to
three years Three to
four years Four to
five years
Non-derivative financial liabilities
Accounts payable and accruals (1) $24,526 $- $- $- $-
Convertible debentures
- Interest (1) 5,626 7,085 3,335
- Principal - 50,000 - 46,00
Total $30,152 $57,085 $3,335 $47,667 $-

1. Accounts payable and accruals includes $1.5 million of interest relating to convertible debentures. The total cash interest payable in less than one year on the convertible debentures is $7.1 million.

(b) Market risk.

Market risk is the risk that changes in market prices, such as commodity prices, foreign exchange rates and interest rates that will affect the Company's earnings 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 are influenced by both U.S. and Canadian supply and demand. The exchange rate effect cannot be quantified, but generally an increase in the value of the Canadian dollar as compared to the U.S. dollar will reduce the prices received by the Company for its petroleum and natural gas sales.

There were no financial instruments denominated in U.S. dollars at March 31, 2014 or December 31, 2013.

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. The Company had no loans outstanding during the three months ended March 31, 2014.

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.

At March 31, 2014 the following derivative contracts were outstanding and recorded at estimated fair value in the amount of $0.6 million:

Type of Contract(1)
Commodity
Volume
Weighted Average
Fixed Price
Remaining Period
Financial swap
Natural gas
2,500 GJ/d $3.55/GJ
April 1, 2014 to December 31, 2014

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

The fair value of derivative contracts at March 31, 2014 was determined using quoted prices in active markets for natural gas, and would have been impacted as follows had the natural gas 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 $0.50 per GJ change in the natural gas prices	$(258)	$258

In December 2013, the Company entered into a physical sales contract to sell 2,500 GJ per day of natural gas between January 1, 2014 and December 31, 2014 at a weighted average AECO price of $3.72 per GJ. This contract remained in effect at March 31, 2014.

Subsequent to March 31, 2014 the Company entered into the following derivative contract for crude oil:

Period	Weighted average volume (bpd)	Weighted average WTI Canadian ($/bbl)
May 1, 2014 to December 31, 2014	500	$110.00

(c) Capital management.

Anderson's objective in managing its capital structure is to safeguard its ability to meet its financial obligations and to fund the future development of its business. The current capital management strategy is designed so that anticipated cash flow from operating activities combined with available credit facilities will fund continued oil and natural gas acquisition, exploration and development activities to grow the value of its asset base for its shareholders. The Company manages its capital structure and makes adjustments to it in the light of changes in economic conditions, the risk characteristics of the underlying assets and its growth opportunities. The Company's capital structure includes working capital, bank loans, convertible debentures, and shareholders' equity. In order to maintain or adjust the capital structure, the Company may, at different times, adjust its capital spending, dispose of certain assets, hedge future commodity prices, buy back convertible debentures or seek other forms of debt or equity financing.

To assess capital and operating efficiency, the Company monitors its bank debt level and working capital. It also monitors the ratio of bank debt and other debt to funds from operations (defined as cash flow from operating activities before changes in non-cash working capital and decommissioning expenditures). The Company prepares annual operating and capital 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. Anderson does not pay dividends.

Anderson's current capital structure is summarized below:

	March 31, 2014	December 31, 2013
Current liabilities(1)	$24,526	$23,417
Current assets(1)	(23,533)	(33,099)
Working capital deficit (surplus)	$993	$(9,682)
Bank loans	-	-
Net debt before convertible debentures	993	(9,682)
Convertible debentures (liability component)(2)	89,517	
Total net debt	$90,510	$79,240
Shareholders' equity	28,840	28,179
Total capitalization	$119,350	$107,419

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

2. Face value of convertible debentures: Series A Debentures $50 million, Series B Debentures $46 million.

Funds from operations were $5.5 million for the three months ended March 31, 2014 (March 31, 2013 - $5.5 million.). Funds from operations are dependent on many factors, including the success of oil and natural gas acquisition, exploration and development activities, commodity prices including quality and basis differentials, royalties, operating, administrative and financing costs, and general market conditions.

Funds from operations, working capital, working capital deficiency, net debt before convertible debentures, total net debt and total capitalization are not defined by IFRS and therefore are referred to as additional GAAP measures.

The Company is subject to a financial covenant associated with its existing credit facility. See note 4. The Company has complied with this financial covenant for the three months ended March 31, 2014. The credit facility is subject to an annual review of the borrowing base which is directly impacted by the value of the oil and natural gas reserves.

12. COMMITMENTS AND CONTINGENCIES

At March 31, 2014, the Company had firm service gas transportation agreements in which the Company guarantees that certain minimum volumes of natural gas will be shipped on various gas transportation systems. The terms of the various agreements expire in one to six 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:

	2014	2015	2016	2017	2018
Firm service commitment	$618	$757	$169	$137	$118
Firm service committed volumes (MMcfd)	4	5	3	3	

There are no material changes to other commitments and contingencies from those disclosed in the Company's annual audited consolidated financial statements as at and for the years ended December 31, 2013 and 2012 other than as described herein. At March 31, 2014, the Company had an obligation under a farm-in agreement to drill one Cardium oil well prior to October 31, 2014 to earn a working interest in the farm-out lands. The capital commitment associated with the well is $2.5 million. Subsequent to March 31, 2014, the Company entered into an agreement to lease office space at a cost of approximately $0.4 million per year from July 1, 2014 to October 30, 2018, subject to customary closing conditions.

Corporate Information

Head Office
2200, 333 - 7th Avenue S.W.
Calgary, Alberta
Canada T2P 2Z1
Phone (403) 262-6307
Fax (403) 261-2792
Website http://www.andersonenergy.ca/

Directors

J.C. Anderson, Calgary, Alberta
Brian H. Dau, Calgary, Alberta
Christopher L. Fong (1)(2)(3), Calgary, Alberta
David J. Sandmeyer (1)(2)(3), Calgary, Alberta, Chairman of the Board
David G. Scobie (1)(2)(3), Calgary, Alberta

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

Officers

Brian H. Dau, President & Chief Executive Officer
David M. Spyker, Chief Operating Officer
M. Darlene Wong, Vice President, Finance, Chief Financial Officer & Corporate Secretary
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

Auditors

KPMG LLP

Independent Engineers

GLJ Petroleum Consultants Ltd.

Legal Counsel

Bennett Jones LLP

Registrar and Transfer Agent

Valiant Trust Company

Stock Exchange

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

Investor Relations Contact

Anderson Energy Ltd.
Brian H. Dau, President & Chief Executive Officer
(403) 262-6307
info@andersonenergy.ca

Abbreviations

bbl - barrel
bpd - barrels per day
BOE - barrels of oil equivalent
BOED - barrels of oil equivalent per day
BOPD - barrels of oil per day
m3 - cubic meters
Mbbls - thousand barrels
MBOE - thousand barrels of oil equivalent
MMBOE - million barrels of oil equivalent
Mstb - thousand stock tank barrels
WTI - West Texas Intermediate
AECO - intra-Alberta Nova inventory transfer price
Bcf - billion cubic feet
GJ - gigajoule
Mcf - thousand cubic feet
Mcfd - thousand cubic feet per day
MMBtu - million British thermal units
MMcf - million cubic feet
MMcfd - million cubic feet per day
NGL - natural gas liquids
Cdn - Canadian
US - United States

CONTACT INFORMATION

Anderson Energy Ltd.
Brian H. Dau, President & Chief Executive Officer
(403) 262-6307
info@andersonenergy.ca