CALGARY, ALBERTA--(Marketwired - Mar 31, 2015) - Anderson Energy Inc. ("Anderson" or the "Company") (TSX:AXL) announces its operating and financial results for the fourth quarter and year ended December 31, 2014. The Company will be filing its audited consolidated financial statements and management's discussion and analysis ("MD&A") for the years ended December 31, 2014 and 2013 on SEDAR today. Copies can be found under the Company's profile on www.sedar.com and on the Company's website at www.andersonenergy.ca.

HIGHLIGHTS

- Anderson completed its 2014/2015 winter program with the drilling of nine Cardium wells. The average initial production rate over the first 30 days ("IP 30") for the seven Cardium wells which have more than 30 days of production data is 397 BOED (82% oil, condensate and NGL). The eighth and ninth wells drilled are on production but do not yet have 30 days of production data. Included in the most recent program was the Company's first long-reach Cardium well which had an IP 30 of 651 BOED (92% oil, condensate and NGL). The best well in the program had an IP 30 of 700 BOED (68% oil, condensate and NGL).

- Production in the fourth quarter was 3,396 BOED (35% oil, condensate and NGL), up 39% from the fourth quarter of 2013. Cardium production represented 2,260 BOED (48% oil, condensate and NGL) of fourth quarter production. 2014 annual production was 3,141 BOED (33% oil, condensate and NGL). The Company's exit rate was 3,400 BOED (41% oil, condensate and NGL). TransCanada Pipelines Ltd. ("TCPL") outages had a negative impact of approximately 82 BOED on the Company's fourth quarter production and such outages continue to negatively impact the Company's first quarter production in 2015, with an estimated average of approximately 430 BOED of production shut-in.

- Funds from operations for the year ended December 31, 2014 were $19.2 million compared to $11.3 million in 2013. For the fourth quarter of 2014, funds from operations were $5.9 million compared to negative funds from operations of $0.3 million in 2013, reflecting growth since the completion of the strategic alternatives process in the fourth quarter of 2013. The operating netback in the fourth quarter of 2014 was $27.53 per BOE compared to $14.81 per BOE in the fourth quarter of 2013. The operating netback from Cardium properties in the fourth quarter of 2014 was $32.79. Operating costs averaged $10.03 per BOE in the fourth quarter of 2014 and $12.43 per BOE for the year, a 30% and 6% reduction respectively from the previous period. Fourth quarter funds from operations were negatively impacted by reductions in commodity prices. Commodity prices in the first quarter of 2015 will be lower than the fourth quarter of 2014. The Company spent $52.1 million on capital expenditures in 2014, in line with its budget, with a capital efficiency of $28,600 per BOED.

- In light of the changes in commodity prices, the Company has made significant changes to its administrative cost structure that are estimated to result in a 15% reduction in general and administrative costs in 2015 when compared to 2014. The Company is also implementing changes in the field, which are estimated to result in operating costs being reduced from the 2014 average of $12.43 per BOE to an average of approximately $10.30 per BOE in 2015. The Company is working with its suppliers and service providers with the goal of reducing capital costs by 30%. These changes, combined with better commodity prices, could motivate the Company to commence drilling again in the second half of 2015.

- The Company's proved plus probable ("P&P") reserves as of December 31, 2014 were 9,210 MMBOE (44% oil, condensate and NGL), 4% higher than at the end of 2013. The Company replaced 202% of its 2014 production with new P&P reserves additions.

- The Company's 2014 finding, development and acquisition ("FD&A") costs for net additions and acquisitions only, including changes to future development costs, were $37.26 per BOE on a total proved ("TP") basis and $21.47 per BOE on a P&P basis. The P&P recycle ratio was 2.0, using an average Cardium net operating income of $42.30 per BOE.

- At December 31, 2014, Cardium P&P reserves were 6.7 MMBOE, a 26% improvement over the prior year. Cardium reserves life indices are 4.8 years on a TP basis and 9.6 years on a P&P basis. The Company replaced 321% of 2014 Cardium production with new P&P Cardium reserves additions.

- On January 23, 2015, the Company completed a corporate reorganization pursuant to a plan of arrangement under the Business Corporations Act (Alberta) (the "Arrangement"). Under the terms of the Arrangement, substantially all of the oil and gas assets previously owned and operated by Anderson Energy Ltd. ("Prior Anderson") were transferred to the Company and all of the outstanding shares of Prior Anderson were sold to a third party together with approximately 500 BOED of non-core, predominantly shallow gas assets for aggregate consideration of $35 million, subject to certain adjustments. The Company has the same employees, directors and shareholders as Prior Anderson. Pro forma this transaction, at December 31, 2014, the Company would have positive working capital of approximately $9.7 million.

FINANCIAL AND OPERATING HIGHLIGHTS

	Three months ended December 31			Year ended December 31		
(thousands of dollars, unless otherwise stated)	*2014*	*2013*	*% Change*	*2014*	*2013*	*% Change*
Oil and gas sales (1)	$ 11,337	$ 8,217	38 %	$ 50,659	$ 53,983	(6
Revenue, net of royalties (1)	$ 10,513	$ 7,288	44 %	$ 46,396	$ 48,850	(5
Funds from operations (2)	$ 5,884	$ (306)	2,023 %	$ 19,195	$ 11,289	70
Funds from operations per share (2) - basic and diluted	$ 0.03	$ -	100 %	$ 0.11	$ 0.07	57

Adjusted loss before taxes [3]	$ (4,136)	$ (2,745)	(51%)	$ (7,538)	$ (17,386)	57
Adjusted loss before taxes per share [3] - basic and diluted	$ (0.02)	$ (0.02)	-	$ (0.04)	$ (0.10)	60
Loss	$ (53,118)	$ (2,445)	2,073%	$ (56,520)	$ (105,601)	46
Loss per share						
Basic and diluted	$ (0.31)	$ (0.01)	3,000%	$ (0.33)	$ (0.61)	46
Capital expenditures (net of proceeds on dispositions)	$ 22,878	$ (71,972)	132%	$ 52,087	$ (63,895)	182
Bank loans and adjusted working capital (deficiency) [2]				$ (24,794)	$ 9,682	(356
Convertible debentures				$ 91,326	$ 88,922	3
Shareholders' equity				$ (27,806)	$ 28,179	(199
Average shares outstanding *(thousands)*:						
Basic and Diluted	172,550	172,550	-	172,550	172,550	-
Ending shares outstanding *(thousands)*				172,550	172,550	-
Average daily sales:						
Oil and condensate *(bpd)*	945	620	52%	841	1,132	(26
NGL *(bpd)*	252	84	200%	184	163	13
Natural gas *(Mcfd)*	13,188	10,467	26%	12,692	13,227	(4
Barrels of oil equivalent *(BOED)* [4]	3,396	2,448	39%	3,141	3,500	(10
Average prices:						
Oil and condensate *($/bbl)*	$ 68.94	$ 83.28	(17%)	$ 90.73	$ 89.73	1
NGL *($/bbl)*	$ 26.92	$ 46.45	(42%)	$ 38.22	$ 40.43	(5
Natural gas *($/Mcf)*	$ 3.75	$ 3.19	18%	$ 4.30	$ 2.93	47
Barrels of oil equivalent *($/BOE)* [4]	$ 36.29	$ 36.49	(1%)	$ 44.19	$ 42.26	5
Realized gain (loss) on derivative contracts *($/BOE)* [5]	$ 4.10	$ (2.96)	239%	$ 0.64	$ (2.75)	123
Royalties *($/BOE)*	$ 2.64	$ 4.13	(36%)	$ 3.72	$ 4.02	(7
Operating costs *($/BOE)*	$ 10.03	$ 14.31	(30%)	$ 12.43	$ 13.25	(6
Transportation costs *($/BOE)*	$ 0.19	$ 0.28	(32%)	$ 0.27	$ 0.31	(13
Operating netback *($/BOE)* [3][5]	$ 27.53	$ 14.81	86%	$ 28.41	$ 21.93	30
Reserves *(MBOE)*: [4]						
Total proved				5,279	5,311	(1
Proved plus probable				9,210	8,822	4
Wells drilled *(gross)*	6	3	100%	13	5	160

(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, adjusted working capital and adjusted 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.

(3) Adjusted loss before taxes, adjusted 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.

(5) Excludes realized loss of $0.2 million related to derivative contracts settled upon the sale of the Garrington and Ferrier Cardium assets for the three months and year ended December 31, 2013.

COMMODITY PRICE COLLAPSE

2014 saw tremendous swings in both oil and natural gas prices. Monthly average West Texas Intermediate ("WTI") oil prices in the first seven months of the year ranged from a low of $94.86 US per bbl in January to a high of $105.15 US per bbl in June. Prices started to slip in the fourth quarter with average monthly prices of $84.34 US per bbl in October, $75.81 US per bbl in November and $59.29 US per bbl in December. The lowest average monthly price seen in 2015 to date was during January at $47.33 US per bbl. Although the US/Canadian dollar exchange rate moved beneficially from approximately $0.90 in 2014 to approximately $0.80 to date in 2015, it does not sufficiently compensate for the collapse in WTI US pricing. As of March 27, 2015, NYMEX futures pricing for WTI from April 1, 2015 to December 31, 2015 is approximately $53.47 US per bbl ($67.47 Canadian per bbl).

In response to the change in oil prices, the Company stopped its drilling program on January 28, 2015, earlier than expected. Three wells that were planned to be drilled were deferred. The Company has no further drilling commitments.

Also in response to the change in oil prices, the Company is focusing its efforts on netback optimization by reducing costs, both in the office and in the field, in preparation for a return to a drilling program in the second half of the year with hopefully better commodity prices.

COST SAVING MEASURES

1) General and administrative ("G&A") expenses: In 2014, the Company's gross G&A (cash) expenses were $8.3 million. Changes were made in the Company's G&A in the first quarter of 2015 which are estimated to reduce G&A (cash) expenses by approximately $1.3 million in 2015 to approximately $7 million. Most of the reductions will be felt in the last three quarters of 2015. These changes include the cancellation of bonuses for management, the reduction in bonuses for staff, the reduction in salaries and benefits for both management and staff and the renegotiation of contracts for other services. Approximately 16% of the Company's G&A (cash) expenses is capitalized and the balance is expensed. Overhead recoveries are estimated to be similar to the prior year. The Company had approximately $0.5 million in gross non-cash stock based compensation costs in 2014, which is estimated to remain essentially unchanged in 2015.

2) Operating expenses: With the reduction in commodity prices, the Company has been focusing on reducing field operating expenses. A significant portion of the Company's operating expense is fixed and relates to legacy shallow gas assets. The Company has or is proceeding to shut in or abandon 74 gross (42.7 net) shallow gas wells and suspend 10 natural gas compressor stations. These wells were producing approximately 172 BOED. The Company has also improved its operating expenses by attracting and collecting third party processing income. The Company's overall operating expenses in 2014 averaged $12.43 per BOE. The Company estimates that it can reduce operating expenses to $10.30 per BOE in 2015, which would be a 17% improvement relative to 2014.

3) Capital expenditures: During past commodity price down cycles, the industry capitalized on the opportunity to make significant reductions in per unit capital costs to improve the economic equation. Similarly, the Company is taking steps to reduce capital costs during the current commodity price down cycle. The Company's goal was to achieve average well payouts of approximately one year when oil prices were in the range of $90 to $100 US WTI per bbl. Today, the Company's payout goal has not changed, but the Company needs to reduce capital costs, reduce operating costs in the field, and admittedly receive better oil pricing than it receives today. Anderson has been working with suppliers and service providers for improved cost efficiency and operations, and believes up to a 30% reduction in capital costs may be achievable. The Company historically has been a leader in low cost Cardium horizontal drilling and completions and is working towards achieving even lower costs.

TCPL OUTAGES

On March 5, 2014, the National Energy Board ("NEB") issued a safety order to TCPL that specified lower than normal operating pressures on certain of TCPL's natural gas pipelines until such time as the integrity of those pipelines can be assessed and an ongoing integrity program approved by the NEB.

On December 15, 2014, TCPL issued a notice to all shippers upstream of James River, Alberta, including the Willesden Green area, regarding the restriction of natural gas volume receipts to certain limits. This order now remains in effect until September 30, 2015.

As a result of the actions taken by TCPL, disruptions to pipeline transportation service in the affected areas (referred to as "outages") forced the Company to curtail production in certain properties within its Willesden Green Cardium area. This included both restricting production rates on newly drilled wells and shutting in older wells, which adversely impacted sales of oil, condensate and NGL, as well as natural gas.

The Company experienced some outages late in the fourth quarter of 2014 where TCPL was conducting maintenance operations. Production was restored in January 2015 but the outages resumed on February 9, 2015 on the Company's northern blocks and continued throughout the rest of the first quarter of 2015. New outages commenced on March 19, 2015 on the Company's central land blocks and on March 23, 2015 on the Company's southern land blocks and are forecasted by TCPL to end on April 2, 2015 and to resume in June 2015.

The Company estimates that the impact of the TCPL outages averaged approximately 82 BOED in the fourth quarter of 2014 and averaged approximately 430 BOED in the first quarter of 2015. The outages are also expected to reduce production in the second quarter of 2015 by approximately 370 BOED. However, due to the fluctuating nature of the outages and the changing forecasts provided by TCPL, it is difficult to estimate the extent of the impact of the outages on the Company's future results.

PLAN OF ARRANGEMENT COMPLETED ON JANUARY 23, 2015

On January 23, 2015, the Company completed the Arrangement that had previously been approved by the common shareholders of Prior Anderson and the Court of Queen's Bench of Alberta. Pursuant to the Arrangement, the common shareholders of Prior Anderson became the common shareholders of the Company and substantially all of the business, assets and liabilities of Prior Anderson were transferred to the Company, other than certain non-core oil and gas assets which were retained by Prior Anderson. The common shares of Prior Anderson were then sold to a third party for $35 million in cash proceeds, as reduced by amounts owing by Prior Anderson under its bank credit facility. The purchase price is subject to adjustment in the event that certain tax attributes of Prior Anderson are less than $222 million, and $1.4 million of proceeds was initially placed in escrow related to possible adjustments.

This non-dilutive financing improved liquidity by approximately $33.5 million (net of expenses) and continues the Company's stated goal of rationalizing its shallow gas assets. The Company will continue to have certain Canadian resource tax pools, and thus remains non-cash taxable. The Company arranged a new $31 million bank facility on the same terms as the Prior Anderson bank facility in place at December 31, 2014.

A copy of the arrangement agreement and related documents are available under Prior Anderson's profile (now 1851328 Alberta Ltd.) at www.sedar.com.

Since the corporate reorganization involved entities under common control, and the business operations of the Company remain the same as Prior Anderson, other than certain assets and related liabilities that were sold to a third party as part of the Arrangement, management has prepared the financial statements, management's discussion and analysis, and this news release for the business formerly owned by Prior Anderson under the name of Anderson Energy Inc., and the results for comparative periods of the Company are those previously reported by Prior Anderson.

Costs associated with the Arrangement of approximately $1 million to December 31, 2014 have been expensed for accounting purposes as reorganization expenses. Remaining costs of approximately $0.5 million are estimated to be incurred and expensed in the first quarter of 2015.

2014/2015 WINTER DRILLING PROGRAM

The Company has completed its 2014/2015 winter drilling program with 9 gross (8.1 net capital, 7.0 net revenue) new Cardium oil wells. Due to weak commodity prices, the drilling of the remaining 3 gross (2.2 net) Cardium wells in the planned program has been deferred. Seven of the nine Cardium oil wells drilled have more than 30 days of initial production. The average production results from the 7 gross (5.3 net revenue) Cardium oil wells have on average exceeded the Company's expectations with an average IP 30 of 397 BOED (82% oil, condensate and NGL).

Included in the most recent seven Cardium well completions was the Company's first long-reach well which had an IP 30 of 651 BOED (92% oil, condensate and NGL) with 32 frac stages over a 1.5 mile horizontal well section. According to an industry publication reviewed by the Company, the Cardium long-reach well was one of the top three new oil wells in Alberta in November 2014. The Cardium long-reach well was the Company's second-best IP 30 BOED well drilled in the 2014/2015 winter drilling program. In addition to the long-reach well, according to another industry publication, two of the Company's other Cardium oil wells were in the top ten new Cardium oil wells in Alberta in December 2014.

The IP 30 and product mix results of the Cardium wells from the 2014/2015 winter drilling program as noted above compares favourably with the 2013/2014 winter drilling program which had an average IP 30 of 511 BOED (53% oil, condensate and NGL). A comparison of the oil, condensate and NGL components of the BOED production for the two drilling programs shows an average IP 30 of 324 barrels per day for the 2014/2015 winter drilling program and 272 barrels per day for the 2013/2014 winter drilling program. Notwithstanding the market perception of the current oil price environment, oil, condensate and NGL remain more valuable than solution gas, and a higher percentage of oil, condensate and NGL in the Company's product mix can be more important to overall revenue and profitability than the overall BOED production rate.

Of the nine Cardium wells drilled in the 2014/2015 winter drilling program, five are in the Central land block, three are in the Northern land block and one is in the Southern land block of the greater Willesden Green area.

The average IP 30 for the Company's 15 Cardium well completions in the greater Willesden Green area on Company lands since December 2012 is 458 BOED (65% oil, condensate and NGL). A recent industry publication indicated an industry average IP 30 of 322 BOED (60% oil, condensate and NGL) for the greater Willesden Green area since 2012.

TECHNOLOGY

By using selective positioning of the horizontal well trajectory, the Company is realizing higher IP 30 production rates than historical Willesden Green area industry averages. The Company has now adopted the use of dissolvable frac balls for toe fracs and has moved to less nitrogen usage in heel fracs. Other changes made this year include a redesigned stage tool to reduce the risk of mechanical wellbore failure.

LIGHT OIL HORIZONTAL DRILLING INVENTORY

The Company's undeveloped light oil horizontal drilling inventory at March 31, 2015, after completion of the winter drilling program, is outlined below:

Prospect Area (number of drilling locations)	*Gross*	*Net**
Willesden Green Cardium	75	56.0
West Pembina/Buck Lake Cardium	26	7.8
Glauconite/Belly River	8	7.3
Total Light Oil Horizontal Drilling Inventory, March 31, 2015	109	71.1

**Net is net revenue interest*

GLJ Petroleum Consultants ("GLJ"), the Company's independent reserves evaluator, booked undeveloped reserves to 22.7 net locations at December 31, 2014, of which 1.6 net locations were drilled in the first quarter of 2015 and the remaining 21.1 net locations are included in the table above.

2015 CAPITAL PROGRAM

The Company estimates production will be 2,200 to 2,400 BOED (46% oil, condensate and NGL) in the first half of 2015, net of estimated TCPL outages of 400 BOED and the impact of approximately 500 BOED of production sold on January 23, 2015. Field capital spending is estimated to be $7 million, most of which occurred in the first quarter of the year. The Company has shut in or is proceeding to abandon 172 BOED of shallow gas production in the first half of the year. The capital budget will be revisited in the second half of the year and, at that time, the Company will be in a better position to provide full year production and capital guidance. The Company is marketing the remainder of it shallow gas assets for sale in the second quarter of this year and that potential disposition is not reflected in the guidance. The greatest risk to the guidance is the extent and duration of current or future TCPL outages and potential oil supply disruptions related to continuing concerns regarding Cushing, Ok lahoma and other US oil storage.

COMMODITY PRICES

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

CRUDE OIL AND CONDENSATE PRICES

	Three months ended December 31		*Year ended December 31*	
	2014	*2013*	*2014*	*2013*
WTI - $US	$ 73.12	97.50	$ 92.92	$ 97.95
WTI - $Cdn	$ 82.90	102.31	$ 102.40	$ 100.95
Differential from Cushing to Edmonton - $US per bbl	$ 6.37	14.92	$ 7.19	$ 7.57
Edmonton Par - $Cdn per bbl	$ 75.51	86.91	$ 94.50	$ 93.33
Anderson average oil price per bbl	$ 68.74	$ 84.26	$ 90.22	$ 89.89
Anderson average oil and condensate price per bbl*	$ 68.94	$ 83.28	$ 90.73	$ 89.73

**Condensate includes field condensate and plant condensate.*

The 2015 monthly WTI Canadian oil prices were approximately $57.35 per bbl in January, $63.38 per bbl in February and $60.57 per bbl in March to March 27, 2015. Differentials from Cushing, Oklahoma to Edmonton, Alberta were approximately $6.97 US per bbl in January, $7.18 US per bbl in February and $6.26 US per bbl in March 2015.

Going forward, light oil prices will remain weak in the short term due to crude inventory levels being at their highest level on record in the US. Over the long term, prices will continue to be volatile and will be influenced by the balance between supply and demand, and by geopolitical events. Cushing, Oklahoma to Edmonton, Alberta differentials will continue to be volatile, as well as movements in the US/Canadian dollar exchange rate.

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 increased the average price received for natural gas to $3.78 per Mcf in the fourth quarter of 2014.

The average heat content of the Company's natural gas has increased from 1,018 Btu/scf in the fourth quarter of 2013 to 1,070 Btu/scf in the fourth quarter of 2014 due to the new Cardium gas having higher heat content than the Company's legacy shallow gas production. Natural gas is sold on the basis of heat content; therefore, higher heat content gas will yield higher prices per unit of measured volume.

NATURAL GAS PRICES

	Three months ended December 31		*Year ended December 31*	
	2014	*2013*	*2014*	*2013*
NYMEX $US per MMBtu	$ 3.84	3.86	4.27	3.73
AECO $CAD per GJ	$ 3.41	3.35	4.25	3.01
AECO $CAD per MMBtu	$ 3.60	3.53	4.48	3.17
Anderson average plant gate price per Mcf before financial derivative or fixed price contracts	$ 3.69	$ 3.19	$ 4.40	$ 2.93

AECO natural gas prices were approximately $2.63 per GJ ($2.77 per MMBtu) in January, $2.60 per GJ ($2.74 per MMBtu) in February and $2.60 per GJ ($2.74 per MMBtu) in March to March 27, 2015.

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

Financial results compared to the prior year reflect the progress made to date since completion of the strategic alternatives process in the fourth quarter of 2013. Production and revenue in the fourth quarter of 2014 were higher than the third quarter of 2014 due to new production from the 2014/2015 drilling program. Funds from operations were $5.9 million in the fourth quarter of 2014 compared to $(0.3) million in the fourth quarter of 2013 and $2.3 million in the third quarter of 2014. Funds from operations were higher than the previous quarter due to higher production volumes and lower costs in the quarter.

On a BOE basis, oil and gas sales averaged $36.29 per BOE in the fourth quarter of 2014 compared to $36.49 per BOE in the fourth quarter of 2013 and $39.54 per BOE in the third quarter of 2014. During the fourth quarter of 2014, liquids revenue (oil, condensate and NGLs) represented 58% of total oil and gas sales. The Company's operating netback was $27.53 per BOE in the fourth quarter of 2014 compared to $14.81 per BOE in the fourth quarter of 2013 and $22.58 per BOE in the third quarter of 2014. Realized hedging gains of $4.10 per BOE offset the decreases in commodity prices in the period. Lower royalties and operating costs per BOE reflect increased production from new wells and the rationalization of gas properties earlier in the year. Anderson's operating netback for Cardium properties in the fourth quarter of 2014 was $32.79 per BOE, exclusive of hedging, compared to $41.09 per BOE in the third quarter of 2014, and $39.54 per BOE in the fourth quarter of 2013. All hedging contracts expired at the end of December 2014.

The Company reported a loss of $53.1 million in the fourth quarter of 2014, including an asset impairment loss of $48.0 million due to the significant decline in the commodity price outlook in the year end reserves evaluation. The Company estimates that it will record a gain on sale of approximately $30 million related to the Arrangement in the first quarter of 2015.

	Average natural gas price ($/Mcf)	*Average oil and condensate price ($/bbl)*	*Revenue ($/BOE)*	*Operating netback ($/BOE)*	*Funds from operations ($/BOE)*
Q1 2014	5.01	97.62	54.54	34.51	20.80
Q2 2014	4.59	103.56	47.13	28.88	17.57
Q3 2014	3.93	96.17	39.54	22.58	9.01
Q4 2014	3.75	68.94	36.29	27.53	18.84

Capital expenditures, net of dispositions, were $52.1 million for the year ended December 31, 2014. Field capital expenditures were $22.9 million in the fourth quarter of 2014 compared to $8.6 million in the third quarter of 2014. Capital investments in the fourth quarter of 2014 were focused on the drilling, completion, equipping and tie-in of Cardium horizontal wells.

Capital efficiency was $28,600 per BOED in 2014, calculated using 2014 total capital expenditures divided by fourth quarter 2014 production volumes from the 2013/2014 and 2014/2015 winter drilling programs.

The 7.5% Series A convertible debentures in the principal amount of $50 million mature on January 31, 2016 and the 7.25% Series B convertible debentures in the principal amount of $46 million mature on June 30, 2017. The dramatic decrease in commodity prices is expected to impact the Company's options with respect to payment of these debentures when they become due. The Company has the option to settle all or a portion of the outstanding debentures through the issuance of common shares by giving notice of such intent to debenture holders not more than 60 and not less than 40 days prior to the applicable maturity date. The Company currently has a $31 million bank facility which is scheduled to be renewed in May 2015, available working capital and potential proceeds from a shallow gas asset disposition process in the second quarter of 2015 as sources of funds which could be used in whole or in part to settle all or part of the January 31, 2016 debenture maturity with cash. Currently the Company does not have sufficient funds to settle the debentures in cash upon their maturity. There is no assurance that the Company will be able to raise sufficient funds to settle the debentures in cash as it still needs the flexibility to continue oil and gas operations. The Board of Directors has hired Cormark Securities Inc. as a financial advisor to assess the Company's options with respect to the convertible debentures.

COMMODITY HEDGING CONTRACTS

The Company has not hedged any crude oil or natural gas volumes at this time.

The Company enters into hedging contracts to protect its capital program and continues to evaluate the merits of additional commodity hedging as part of a price management strategy.

RESERVES

GLJ has completed a reserves report (the "GLJ Report") of all the Company's oil and natural gas properties effective December 31, 2014, prepared in accordance with procedures and standards contained in National Instrument 51-101 of the Canadian Securities Administrators ("NI 51-101") and the Canadian Oil and Gas Evaluation Handbook ("COGE Handbook"). The reserves definitions used in preparing the report are those contained in the COGE Handbook and NI 51-101. As of December 31, 2014, the Company had 3,704 MBOE proved developed producing ("PDP") reserves (38% oil and NGL), 5,279 MBOE total proved ("TP") reserves (40% oil and NGL) and 9,210 MBOE P&P reserves (44% oil and NGL). The GLJ price forecast used in the evaluation is shown in the MD&A for the year ended December 31, 2014.

The report includes the properties sold as part of the Arrangement completed on January 23, 2015 as this transaction did not occur until after the end of the year. For the same reason, the report does not include the value of new joint venture processing and operating agreements signed as part of the Arrangement. The report also does not include the impact of operating cost initiatives undertaken in the first quarter of 2015. The capital costs per undeveloped drilling location in the reserves report is based on historical capital costs and does not reflect management's current views on the potential to reduce capital costs going forward.

The Cardium formation represents approximately 61%, 63% and 73% respectively of PDP, TP and P&P total BOE reserves volumes and 91%, 89% and 89% respectively of the total Company PDP, TP and P&P net present value using a 10% discount rate ("NPV 10"). The Cardium reserves life indices are 4.8 years for TP reserves and 9.6 years for P&P years. Cardium PDP, TP and P&P annual reserves growth was 68%, 28% and 26% respectively.

Of the 9 Cardium wells drilled in the 2014/2015 program, there are 2 wells that were drilled in the first quarter of 2015, and so were not included as PDP reserves. If these wells had been included as PDP reserves it would have added approximately 176 MBOE to PDP reserves (based on a simple conversion of proved undeveloped to proved developed producing).

SUMMARY OF OIL AND GAS RESERVES

	December 31, 2014					*December 31, 2013*				
Gross Working Interest Oil and Gas Reserves	Oil *(Mbbls)*	NGL[(1)] *(Mbbls)*	Gas *(MMcf)*	Total (MBOE)	Pre-tax NPV 10 *($M)*[(2)]	Oil *(Mbbls)*	NGL[(1)] *(Mbbls)*	Gas *(MMcf)*	Total *(MBOE)*	Pre-tax NPV 10 *($M)*[(2)]
Proved developed producing	1,093	315	13,772	3,704	51,637	792	216	14,639	3,447	43,153
Proved developed non-producing	25	17	2,881	522	2,535	128	25	3,683	767	7,527
Total proved	1,716	414	18,896	5,279	60,644	1,608	313	20,336	5,311	61,608
Proved plus probable	3,257	755	31,187	9,210	96,138	3,150	565	30,642	8,822	100,312

(1) NGL in the GLJ reserves report includes condensate and other NGL

(2) 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.

The total pre-tax P&P NPV 10 value of reserves was 4% lower than last year. While P&P reserves volumes increased by 9% before adjustment for economic factors, reductions in price forecasts reduced both volumes (economic factors) and values. The average price forecast reduction in the first five years in GLJ's price deck was 15% for Edmonton Par oil prices (30% in the first year) and 12% for AECO natural gas prices. Cardium pre-tax PDP, TP and P&P NPV 10 value increased 49%, 13% and 6% respectively over the previous year in spite of the price forecast reductions.

CONTINUITY OF GROSS WORKING INTEREST RESERVES

	Proved Developed Producing (MBOE)	*Total Proved (MBOE)*	*Proved* Plus Probable *(MBOE)*
Opening Balance, December 31, 2013	3,447	5,311	8,822
Extensions and improved recovery	1,277	933	1,686
Technical revisions	235	161	(384)
Acquisitions	243	386	668
Dispositions	(26)	(32)	(40)
Economic factors	(326)	(334)	(396)
Production	(1,146)	(1,146)	(1,146)
Closing Balance, December 31, 2014	3,704	5,279	9,210

The Company will provide more detailed information from its current reserves report in its Annual Information Form for the year ended December 31, 2014.

The Company replaced 112% of its production with TP reserves additions and 202% of its production with P&P reserves additions, excluding technical revisions and economic factors. For Cardium reserves only, the ratios were 187% and 321% respectively.

The Company's future development costs as of December 31, 2014 are $28.8 million and $66.4 million respectively for TP and P&P reserves. For P&P reserves, future development costs are $2.2 million or 3% lower than at December 31, 2013. Future development costs are associated with the reserves disclosed in the GLJ report and do not necessarily represent the Company's current exploration and development budget.

The Company's finding, development and acquisition ("FD&A") costs for net additions before technical revisions, including the change in future development costs are estimated to be $37.26 per BOE for TP reserves and $21.47 for P&P reserves. Including technical revisions, these costs are estimated to be $33.11 for TP reserves and $25.73 for P&P reserves. The recycle ratio for net additions only was 1.1 for TP reserves and 2.0 for P&P reserves using an average Cardium net operating income of $42.30 per BOE and 2014 FD&A costs. Net additions include extensions and improved recovery, acquisitions (largely farm-ins) and dispositions. The Company has only provided FD&A estimates since the completion of the strategic alternatives process. Three year estimates were considered to be meaningless given the significant property dispositions that occurred in 2012 and 2013. The Company believes that finding and development costs should include acquisition and disposition volumes and changes in future development costs for acquisitions and dispositions as it is a very useful and commonly used reference for its shareholders. More discussion of FD&A is included in the MD&A. It should be noted that the aggregate of the exploration and development costs incurred in the most recent financial year and the change during that year in estimated future development costs generally will not reflect total finding and development costs related to reserves additions in the year.

Oil, condensate and NGL as a percentage of total MBOE reserves has increased to 38% of PDP, 40% of TP and 44% of P&P reserves from 29%, 36% and 42% respectively in 2013.

UNDEVELOPED LAND

Anderson has 70,016 gross (28,608 net) undeveloped acres of land at December 31, 2014. Undeveloped land value has been estimated at $4.3 million by management.

NET ASSET VALUE

As a result of the Arrangement that closed on January 23, 2015, the Company completed a net asset value estimate using GLJ December 31, 2014 price and cost assumptions, pro forma this non-dilutive financing disposition:

($'000 except as otherwise stated)	
December 31, 2014 NPV 10 of P&P reserves *(1)*	$ 96,138
Less NPV 10 of P&P reserves for properties sold as part of Arrangement on January 23, 2015 *(1)*	(6,170)
Add net proceeds received as part of Arrangement on January 23, 2015	34,500
Add undeveloped land	4,276
Less net debt including face value of debentures	(120,794)
Net asset value *(2)*	$ 7,950
Net asset value per fully diluted share *(2)(3)*	$ 0.05

(1) GLJ includes 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.

(2) Does not include management's estimated value for approximately 70% of the net drilling inventory not included in GLJ reserves report at December 31, 2014, or the value of new joint venture processing and operating agreements signed as part of the Arrangement that closed on January 23, 2015.

(3) Based on 172.5 million outstanding shares on a fully diluted basis at December 31, 2014.

OWNERSHIP

The management team of Anderson has been together for the last 13 years in the Company's private and public phases. They currently own 6.9 million shares, adding 0.75 million shares in 2014. Including the Board of Directors, insiders own 19.2 million or 11% of the outstanding common shares and 2.5% of the convertible debentures. Both management and the directors have a vested interest in maximizing the value of the Company on behalf of all of its stakeholders and, in spite of the difficult oil price trauma during the last few months, there is opportunity to reduce costs within the office and the field and potentially resume drilling in the second half of the year.

SUMMARY

In summary, the Company has made significant progress since completion of the strategic alternatives process in the fourth quarter of 2013. The Company has grown liquids production and reserves through development of its Cardium assets. Oil, condensate and NGL made up 41% of total BOED exit production in 2014 compared to 26% in the fourth quarter of 2013 (net of properties sold). Reserves volumes on a BOE basis increased 9% before economic factor adjustments, with Cardium P&P reserves now making up 73% of total reserve volumes on BOE basis, compared to 60% at the end of 2013. The Cardium program delivered excellent results with a P&P recycle ratio of 2.0, a FD&A cost on a P&P basis of $21.47 per BOE, a capital efficiency ratio of $28,600 per BOED, and Cardium production growth of 100% from January 2014 to January 2015. The Company continues to have stellar drilling results, outpacing the average performance of industry competitors in the Willesden Green field in terms of lower capital costs and higher IP 30 rates. The Arrangement provided additional non-dilutive liquidity for the Company. Anderson's reaction to the oil price collapse was to terminate its capital program early, to not incur bank debt and to leave cash in the bank for the future. Anderson has also taken significant strides to reduce head office costs, field operating costs and to bring down capital costs. The Company will be marketing its shallow gas assets in the second quarter of 2015, which if sold will further improve its liquidity. All of these initiatives will help the Company in the future.

There are a lot of challenges in front of us, but we believe that oil prices will correct upward in the future, TCPL will finally complete their maintenance and then, when economic and financial conditions dictate, we can be back in the field drilling with a new economic equation.

I appreciate the support of the Board of Directors and the financial sacrifices that staff and management had to make to reposition the Company for the future. The Company's most recent investor presentation will be posted on the Company's website at www.andersonenergy.ca.

Thanks for your patience.

Brian H. Dau
President & Chief Executive Officer
March 31, 2015

FORWARD-LOOKING STATEMENTS

Certain statements in this news release including, without limitation, management's business strategy and assessment of future plans and operations; benefits and valuation of the development prospects described herein; number of locations in drilling inventory; drilling program success; timing and location of drilling and tie-in of wells and the costs thereof; timing of construction of facilities; timing of shut-in and abandonment of wells and impact thereof; productive capacity of the wells; expected production rates and risks to such expectations; improved production from slick water fracture technology; percentage of production from oil, condensate 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; reserves and net present value of future net revenue from reserves; ability to attain cost savings and amount thereof; tax horizon; ability to improve operating netbacks; 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; the impact of the TCPL outages on past and future production; benefits of recently completed transactions including the result on the Company's liquidity; settlement of convertible debenture liabilities and method of such settlement; 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; availability of third-party transportation and processing facilities; 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.

CONVERSION MEASURES AND SHORT-TERM PRODUCTION RATES

Production volumes and reserves are commonly expressed on a BOE basis whereby natural gas volumes are converted at the ratio of six thousand cubic feet to one barrel of oil. 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 six Mcf to one 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.

This news release contains production information obtained from reports prepared by certain third parties. None of the authors of such reports has provided any form of consultation, advice or counsel regarding any aspect of this news release and the Company does not warrant the accuracy or completeness of the third party information. Industry data is subject to variations and cannot be verified due to limits on the availability and reliability of data inputs, the voluntary nature of the data gathering process and other limitations and uncertainties inherent in any market or other survey.

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 or reserves. Individual well performance may vary.

ABBREVIATIONS

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

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