CALGARY, ALBERTA--(Marketwired - May 15, 2015) - Anderson Energy Inc. ("Anderson" or the "Company") (TSX:AXL) announces its operating and financial results for the first quarter ended March 31, 2015. The Company will be filing its unaudited condensed interim financial statements and management's discussion and analysis ("MD&A") for the three months ended March 31, 2015 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

- The average initial production rate over the first 30 days ("IP 30") for the nine Cardium horizontal light oil wells drilled in the 2014/2015 winter program was 413 BOED per well (85% oil, condensate and NGL). The program includes the Company's first long-reach 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 707 BOED (71% oil, condensate and NGL).
- Production in the first quarter of 2015 was 2,704 BOED (46% oil, condensate and NGL), compared to 3,396 BOED (35% oil, condensate and NGL) for the fourth quarter of 2014. Production was affected by the sale of approximately 500 BOED of non-core, predominantly shallow gas production as part of a corporate reorganization completed on January 23, 2015. Production was also affected by the shut-in of approximately 320 BOED of Cardium production as a result of the TransCanada Pipelines Ltd. ("TCPL") outages. Cardium production was 2,006 BOED (58% oil, condensate and NGL) in the first quarter of 2015. The Company is currently marketing the remainder of its shallow gas assets for disposition in the second quarter of 2015.
- Funds from operations were $0.3 million in the first quarter of 2015 compared to $5.9 million in the fourth quarter of 2014 and decreased due to dramatic reductions in commodity prices. Oil and gas revenue per BOE decreased 21% from the previous quarter and 47% from the first quarter of 2014. The operating netback was $14.98 per BOE in the first quarter of 2015 compared to $27.53 per BOE in the fourth quarter of 2014. The operating netback from Cardium properties in the first quarter of 2015 was $22.14 per BOE. Operating expenses were $10.39 per BOE compared to $10.03 per BOE in the fourth quarter of 2014 and $13.28 per BOE in the first quarter of 2014. Capital expenditures, before proceeds on dispositions, were $6.9 million, as budgeted. As of March 31, 2015 the Company had adjusted positive working capital of $2.8 million, with $14.9 million of cash in the bank. The Company is currently undrawn on its $31 million bank facility.
- 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 has also implemented changes in the field, which are estimated to result in operating costs being reduced from the 2014 average of $12.43/BOE to an average of approximately $10.30/BOE in 2015. The Company is looking at opportunities to re-engineer its completions operations and is also 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.
- 109 gross (71.1 net) light oil horizontal drilling locations have been identified in the Cardium, Glauconite, and Belly River zones (90% of net locations are in the Cardium zone). Only 31% of the net locations are recognized as P&P locations in the year end reserves report. Approximately 97% of the net locations are Company operated.
- On January 23, 2015, the Company completed a corporate reorganization pursuant to a plan of arrangement under the Business Corporations Act (Alberta) (the "Arrangement") whereby 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 directors, management, employees and shareholders as Prior Anderson.

FINANCIAL AND OPERATING HIGHLIGHTS

	Three months ended March 31		
(thousands of dollars, unless otherwise stated)	*2015*	*2014*	*% Change*
Oil and gas sales[1]	$ 6,989	$ 14,522	(52 %)
Revenue, net of royalties[1]	$ 6,253	$ 13,195	(53 %)
Funds from operations[2]	$ 275	$ 5,538	(95 %)
Funds from operations per share[2] - basic and diluted	$ -	$ 0.03	(100 %)
Adjusted earnings before taxes[3]	$ 24,300	$ 544	4,367 %
Adjusted earnings before taxes per share[3] - basic and diluted	$ 0.14	$ -	100 %
Earnings	$ 23,923	$ 544	4,298 %
Earnings per share			
Basic and diluted	$ 0.14	$ -	100 %
Capital expenditures (net of proceeds on dispositions)	$ (28,158)	$ 16,032	(276 %)
Bank loans and adjusted working capital (deficiency)[2]	$ 2,822	$ (993)	384 %
Convertible debentures	$ 91,968	$ 89,517	3 %
Shareholders' equity	$ (3,753)	$ 28,840	(113 %)
Average shares outstanding *(thousands)*:			
Basic	172,550	172,550	-
Diluted	172,550	172,943	-
Ending shares outstanding *(thousands)*	172,550	172,550	-

Average daily sales:				
Oil and condensate *(bpd)*	1,089	1,017	7	%
NGL *(bpd)*	162	122	33	%
Natural gas *(Mcfd)*	8,716	10,920	(20	%)
Barrels of oil equivalent *(BOED)*[4]	2,704	2,958	(9	%)
Average prices:				
Oil and condensate *($/bbl)*	$ 47.90	$ 97.62	(51	%)
NGL *($/bbl)*	$ 13.68	$ 55.74	(75	%)
Natural gas *($/Mcf)*	$ 2.65	$ 5.01	(47	%)
Barrels of oil equivalent *($/BOE)*[4]	$ 28.72	$ 54.54	(47	%)
Realized loss on derivative contracts *($/BOE)*	$ -	$ (1.53	) 100	%
Royalties *($/BOE)*	$ 3.02	$ 4.99	(39	%)
Operating costs *($/BOE)*	$ 10.39	$ 13.28	(22	%)
Transportation costs *($/BOE)*	$ 0.33	$ 0.23	43	%
Operating netback *($/BOE)*[3]	$ 14.98	$ 34.51	(57	%)
Wells drilled *(gross)*	2	4	(50	%)

[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 earnings before taxes, adjusted earnings 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.*

TCPL OUTAGES

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 notice 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") resulted in a restriction on the Company's production of certain properties within its Willesden Green Cardium area.

Although some of the impact of the TCPL outages during the first quarter of 2015 involved restrictions to a historical stream of production, much of the impact related to the estimated production from new wells drilled during the 2014/2015 winter drilling program that was deferred as a result of the outages. The impact of the TCPL outages for the first half of 2015 is currently estimated to be approximately 345 BOED including the estimated restriction of production from these new wells. The restrictions affect the production of oil, condensate and NGL as well as natural gas. These restrictions on production are expected to be temporary and affect production at varying rates and times through the second and third quarters of 2015, and will defer the affected production until future periods. 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.

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 to 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 impact 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 15% of the Company's G&A (cash) expenses are 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 expenses are 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 is looking at opportunities to re-engineer its completions operations and is also working with suppliers and service providers for improved cost efficiency and operations, and believes a 30% reduction in capital costs may be achievable as a result of these initiatives. The Company historically has been a leader in low cost Cardium horizontal drilling and completions and is working towards achieving even lower costs.

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 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 condensed interim financial statements, MD&A, 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 $0.4 million in the three months ended March 31, 2015 and $1 million to December 31, 2014 have been expensed for accounting purposes as reorganization expenses. Remaining costs of approximately $0.1 million are estimated to be incurred and expensed in the second 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. The nine Cardium oil wells drilled have more than 30 days of initial production and an average IP 30 of 413 BOED (85% oil, condensate and NGL). Included in the most recent drilling program was the Company's first long-reach well which had an IP 30 of 651 BOED (92% oil, condensate and NGL). The best well in the nine-well program had an IP 30 of 707 BOED (71% oil, condensate and NGL).

Of the nine Cardium wells drilled in the 2014/2015 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 IP 30 and product mix results from the Cardium wells in the 2014/2015 winter drilling program 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 349 barrels per day for the 2014/2015 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 overall BOED production rate.

The average IP 30 for the 19 Cardium wells completed with slick water fracture stimulation in the Willesden Green area on Company lands since June 2012 was 469 BOED (68% oil, condensate and NGL). The best single well IP 30 result from these

wells was 1,119 BOED (67% 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 mechanical wellbore failure.

LIGHT OIL HORIZONTAL DRILLING INVENTORY

The Company's undeveloped light oil horizontal drilling inventory at May 15, 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, May 15, 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 the impact of approximately 500 BOED of production sold on January 23, 2015. As the TCPL outages in the first quarter of 2015 were less than originally estimated, the production estimate for the first half of the year is now expected to be at the higher end of this range, assuming TCPL outages of approximately 370 BOED in the second quarter. Field capital spending is estimated to be $7 million for the first half of 2015, 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 the Company will be in a better position to provide full year production and capital guidance at that time. The Company is currently marketing the remainder of it shallow gas assets for disposition 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, Oklahoma 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 March 31	
	2015	*2014*
WTI - $US	$ 48.56	$ 98.62
WTI - $Cdn	$ 60.28	$ 108.83
Differential from Cushing to Edmonton - $US per bbl	$ 6.79	$ 8.35
Edmonton Par - $Cdn per bbl	$ 51.70	$ 100.04
Anderson average oil price per bbl	$ 47.81	$ 97.36
Anderson average oil and condensate price per bbl*	$ 47.90	$ 97.62

**Condensate includes field condensate and plant condensate.*

The 2015 monthly WTI Canadian oil prices were approximately $67.36 per bbl in April and $72.26 per bbl to date in May. Differentials from Cushing, Oklahoma to Edmonton were approximately $4.93 US per bbl in April, $2.81 US per bbl for May and $0.92 per bbl to date for June.

Going forward, light oil prices are expected to remain weak in the short term due to crude oil 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.

NATURAL GAS PRICES

	Three months ended March 31	
	2015	*2014*
NYMEX US$ per MMBtu	$ 2.82	$ 4.72
AECO $CAD per GJ	2.61	5.36
AECO $CAD per MMBtu	2.75	5.66
Anderson average plant gate price per Mcf	$ 2.65	$ 5.38

AECO natural gas prices were approximately $2.42 per GJ ($2.55 per MMBtu) in April and $2.63 per GJ ($2.77 per MMBtu) month to date in May.

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 $0.3 million in the first quarter of 2015 compared to $5.9 million in the fourth quarter of 2014 and $5.5 million in the first quarter of 2014 and decreased due to dramatic reductions in both oil and natural gas prices. Benchmark prices for both commodities in the first quarter of 2015 were almost half of what they were in the first quarter of 2014.

On a BOE basis, oil and gas revenue averaged $28.72 per BOE in the first quarter of 2015 compared to $36.29 per BOE in the fourth quarter of 2014. During the first quarter of 2015, oil, condensate and NGL revenue represented 70% of total revenue. The Company's operating netback was $14.98 per BOE in the first quarter of 2015 compared to $27.53 per BOE for the fourth quarter of 2014. The decrease in operating netback was driven by lower oil and gas prices. Anderson's operating netback for Cardium properties in the first quarter of 2015 was $22.14 per BOE compared to $32.79 per BOE in the fourth quarter of 2014.

Earnings were $23.9 million in the first quarter of 2015 compared to a loss of $53.1 million in the fourth quarter of 2014 and earnings of $0.5 million for the first quarter of 2014.

The Company recorded a gain on sale of $30.2 million related to the Arrangement in the first quarter of 2015. The loss of $53.1 million in the fourth quarter of 2014 included an asset impairment loss of $48.0 million due to the significant decline in the commodity price outlook in the year end reserves evaluation.

Capital expenditures, before proceeds from dispositions, were $6.9 million in the first quarter of 2015 compared to $23.1 million in the fourth quarter of 2014. The Company terminated its drilling program in January 2015 due to the dramatic drop in commodity prices. Capital investments in the first quarter of 2015 were focused primarily on the drilling, completion, equipping and tie-in of Cardium horizontal oil wells.

Subsequent to March 31, 2015, the Company received an indicative term sheet to renew its bank facility at the existing $31 million level, subject to the completion of certain closing conditions. The term date and maturity date are expected to be extended to May 31, 2016 and May 31, 2017, respectively. The renewal incorporates both the recent reductions in commodity prices and the sale of certain non-core assets in the first quarter of 2015.

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, available working capital and potential proceeds from a shallow gas asset disposition process in the second quarter of 2015 as sources of funds that 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 with cash upon their maturity. There is no assurance that the Company will be able to raise sufficient funds to settle the debentures with 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.

ANNUAL AND SPECIAL MEETING OF SHAREHOLDERS

The Company's annual and special meeting of shareholders (the "Meeting") is scheduled for 10:00 a.m. on June 25, 2015 at the Westwinds Conference Room, 2nd Floor Selkirk House, 555 4th Avenue S.W., Calgary, Alberta.

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 oil, condensate and NGL production and reserves through development of its Cardium assets. Oil, condensate and NGL made up 46% of total BOED production in the first quarter of 2015 compared to 26% in the fourth quarter of 2013 (net of properties sold), when the Company emerged from the strategic alternatives process. Cardium production growth in the Willesden Green area was 81% for oil and 137% on a BOE basis from January 2014 to January 2015. Reserves volumes on a BOE basis increased 9% before economic factor adjustments, with Cardium P&P reserves now making up 73% of total reserves volumes on BOE basis, compared to 60% at the end of 2013. The Cardium program delivered excellent results with a proved plus probable ("P&P") recycle ratio of 2.0, a finding, development and acquisition cost on a P&P basis of $21.47 per BOE (including changes in future development costs, but excluding technical revisions and economic factors) and a capital efficiency ratio of $28,600 per BOED. The Company continued 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.

Oil prices have been stronger to date in the second quarter than in the first quarter of 2015 as worldwide supply and demand for crude oil becomes closer to being balanced. With less industry spending, increased demand for crude oil driven by lower prices, and general production declines, oil supply and demand will ultimately become balanced and the market will then present the opportunity for upward price corrections.

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.

Thank you for your continued patience.

Brian H. Dau, President & Chief Executive Officer

May 15, 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; anticipated extension of the bank facility; 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

Contact

Anderson Energy Inc.
Brian H. Dau
President & Chief Executive Officer
403-262-6307
403-261-2792
www.andersonenergy.ca