

ANDERSON ENERGY ANNOUNCES 2009 THIRD QUARTER RESULTS

Calgary, Alberta, November 16, 2009 - Anderson Energy Ltd. ("Anderson Energy" or the "Company") (TSX:AXL) is pleased to announce its operating and financial results for the third quarter ended September 30, 2009.

HIGHLIGHTS:

- The Board of Directors has approved an amended 2009 capital budget of \$33 million and a preliminary 2010 capital budget of \$75 million. Associated production guidance estimates for 2010 are 8,000 to 8,500 BOED. The Company estimates it will spend approximately \$10 million during the fourth quarter of 2009 and \$36 million in the first quarter of 2010, net of anticipated drilling incentive credits.
- The Company is planning to drill approximately 100 Edmonton Sands wells in the fourth quarter of 2009 and 26 in the first quarter of 2010. For 2010, the Company is planning to drill 101 Edmonton Sands wells, five deep wells targeting the Mannville and Rock Creek liquids rich gas formations and four horizontal multistage frac wells targeting Whitemud gas and Cardium oil formations.
- The Company has identified high impact multistage frac horizontal drilling opportunities with a potential inventory of up to 436 gross (260 net) locations targeting the Whitemud gas formation and Cardium oil in Central Alberta. The Company's first multistage frac horizontal well is expected to spud in the first quarter of 2010.
- The Company is planning on building two new fit-for-purpose Edmonton Sands gas plants and connecting newly drilled wells to six other facilities this winter. The Company has a working interest in three of the six facilities. New production from the winter drilling program is expected to be on-stream by April 1, 2010 at an average operating expense of \$5.00 per BOE.
- The semi-annual bank line review has been completed and the Company's lenders have maintained the Company's credit facilities of \$100 million.
- Funds from operations were \$6.6 million (\$0.04 per share) in the third quarter of 2009 down 69% from the third quarter of 2008 due to a 60% decline in commodity prices and lower production. The Company had 440 BOED of production shut-in due to lower commodity prices and NGL facility issues.
- The average royalty rate as a percentage of revenue was 6% in the third quarter of 2009 compared to 20% in the comparable quarter of 2008, primarily due to higher gas cost allowance and the effect of lower natural gas prices on Crown royalties paid.
- The Company was successful in reducing operating expenses in the third quarter of 2009 to \$7.72 per BOE, a 24% decrease from the comparable quarter of 2008 and a 19% decrease from the second quarter of 2009. This number reflects some reversals of prior quarter accruals where the effect of cost reductions had previously been under estimated. Operating expenses averaged \$9.45 per BOE for the nine months ended 2009 and were 16% lower than the same period in 2008. The Company's planned winter drilling program and new plant

construction plans will provide further opportunities to reduce operating expenses by the second quarter of 2010.

FINANCIAL AND OPERATING HIGHLIGHTS

<i>(thousands of dollars, unless otherwise stated)</i>	<i>Three months ended September 30</i>			<i>Nine months ended September 30</i>		
	<i>2009</i>	<i>2008</i>	<i>% Change</i>	<i>2009</i>	<i>2008</i>	<i>% Change</i>
Oil and gas revenue before royalties	\$ 14,617	\$ 39,427	(63%)	\$ 56,554	\$ 126,143	(55%)
Funds from operations	\$ 6,623	\$ 21,212	(69%)	\$ 22,107	\$ 66,124	(67%)
Funds from operations per share						
Basic	\$ 0.04	\$ 0.24	(83%)	\$ 0.19	\$ 0.76	(75%)
Diluted	\$ 0.04	\$ 0.24	(83%)	\$ 0.19	\$ 0.76	(75%)
Earnings (loss)	\$ (9,432)	\$ 4,160	(327%)	\$ (30,001)	\$ 14,365	(309%)
Earnings (loss) per share						
Basic	\$ (0.06)	\$ 0.05	(220%)	\$ (0.26)	\$ 0.16	(263%)
Diluted	\$ (0.06)	\$ 0.05	(220%)	\$ (0.26)	\$ 0.16	(263%)
Capital expenditures, including acquisitions net of dispositions	\$ 6,571	\$ 27,068	(76%)	\$ 22,246	\$ 79,199	(72%)
Debt, net of working capital				\$ 69,819	\$ 110,535	(37%)
Shareholders' equity				\$ 338,746	\$ 350,110	(3%)
Average shares outstanding <i>(thousands)</i>						
Basic	150,500	87,300	72%	116,470	87,297	33%
Diluted	150,500	87,300	72%	116,470	87,400	33%
Ending shares outstanding <i>(thousands)</i>				150,500	87,300	72%
Average daily sales:						
Natural gas <i>(Mcf)</i>	36,282	38,703	(6%)	39,685	39,263	1%
Liquids <i>(bpd)</i>	1,013	1,221	(17%)	1,166	1,277	(9%)
Barrels of oil equivalent <i>(BOED)</i>	7,060	7,671	(8%)	7,780	7,820	(1%)
Average prices:						
Natural gas <i>(\$/Mcf)</i>	\$ 2.81	\$ 7.86	(64%)	\$ 3.85	\$ 8.57	(55%)
Liquids <i>(\$/bbl)</i>	\$ 53.84	\$ 90.19	(40%)	\$ 46.19	\$ 90.43	(49%)
Barrels of oil equivalent <i>(\$/BOE)</i>	\$ 22.50	\$ 55.87	(60%)	\$ 26.63	\$ 58.87	(55%)
Royalties <i>(\$/BOE)</i>	\$ 1.24	\$ 11.43	(89%)	\$ 3.07	\$ 12.76	(76%)
Operating costs <i>(\$/BOE)</i>	\$ 7.72	\$ 10.10	(24%)	\$ 9.45	\$ 11.19	(16%)
Operating netback <i>(\$/BOE)</i>	\$ 13.54	\$ 34.34	(61%)	\$ 14.11	\$ 34.92	(60%)
General and administrative <i>(\$/BOE)</i>	\$ 2.18	\$ 2.90	(25%)	\$ 2.39	\$ 2.51	(5%)
Wells drilled <i>(gross)</i>	-	39	(100%)	11	126	(91%)

2009 THIRD QUARTER IN REVIEW

As planned, the Company was not operationally active in the third quarter. No wells were drilled in the quarter. Four gross (four net) wells were tied in for production. Funds were being conserved for the drilling program that commenced in the fourth quarter. Activity in the third quarter was focused on planning and bidding out contracts for that program.

For the three months ended September 30, 2009, production averaged 7,060 BOED, with behind pipe at the end of the quarter being 830 BOED. The Company had 300 BOED of gas production shut-in during the quarter due to poor natural gas prices and 140 BOED of ethane production shut-in due to the non-operated deep cut facility not running at Bigoray. The Company expects 340 BOED of shut-in production to resume by December of this year.

Capital expenditures were \$6.6 million in the third quarter of 2009, which included \$3 million to purchase production casing that will be used throughout the upcoming winter drilling program and \$1.5 million of additional pre-drilling costs associated with this winter's capital program.

The Company's funds from operations were \$6.6 million in the third quarter of 2009 compared to \$21.2 million in the third quarter of 2008. The Company's average natural gas sales price was only \$2.81 per Mcf in the third quarter of 2009 compared to \$7.86 per Mcf in the third quarter of 2008. The Company's average crude oil and natural gas liquids sales price in the third quarter of 2009 was \$53.84 per bbl compared to \$90.19 per bbl in the third quarter of 2008. The Company's operating netback was \$13.54 per BOE in the third quarter of 2009 compared to \$34.34 per BOE in the same quarter of 2008. The change in the operating netback was primarily due to lower commodity prices partially offset by lower operating expenses and lower royalties. The average royalty rate as a percentage of revenue in the third quarter of 2009 was 6% compared to 20% in the third quarter of 2008. The reduction is primarily due to the effect of higher gas cost allowance and the effect of lower natural gas prices on Crown royalties paid. When prices and corresponding revenues are lower, gas cost allowance credits become more significant to the overall royalty rate. Royalties were 12% of revenue for the nine months ended September 30, 2009 compared to 22% for the same period in 2008. In the nine months ended September 30, 2009, the Company received \$2.3 million more in gas cost allowance adjustments than had previously been accrued relating to 2008. Royalty rates would have been 13% for the quarter and 16% for the year to date without these adjustments. Operating expenses in the third quarter of 2009 were \$7.72 per BOE, which is 24% lower than the comparable quarter of 2008 and 19% lower than the second quarter of 2009. For the nine months ended September 30, 2009, operating expenses averaged \$9.45 per BOE, which is 16% lower than the same period in 2008. Earlier in the year, the Company implemented various operating expense reduction initiatives on its asset base, including negotiations with service providers and the shut-in of higher cost production. The \$7.72 per BOE reported in the third quarter of 2009 reflects the reversal of some prior quarter accruals where the effect of cost reductions had previously been underestimated. Year to date operating expenses of \$9.45 per BOE are more reflective of current operating expenses.

FARM-IN TRANSACTION

On January 30, 2009, the Company announced a significant farm-in transaction (the "Farm-In") with an international oil company in its Edmonton Sands project area.

Anderson Energy believes that the transaction will deliver significant benefits to the Company and will define it as the major Edmonton Sands resource player in Central Alberta. Through the Farm-In, the Company more than doubles its land and prospect inventory in its primary core area. The Company will preserve its financial position through 2010 by focusing the 2009/2010 winter drilling program primarily on earning new lands under the Farm-In and deferring drilling on equal opportunities on existing lands.

Under the Farm-In, the Company has access to 388 gross (205 net) sections of land in the middle of the Edmonton Sands fairway. Anderson Energy has identified 293 sections with Edmonton Sands drilling potential on the lands.

During the commitment phase of the Farm-In, the Company is committed to drill, complete and equip 200 wells to earn an interest in up to 120 sections. The Company is obligated to complete the drilling of the wells on or before December 31, 2010. The Company's equipping obligation is up to, but does not include, multi-well gathering systems downstream of field compression and/or gas plants. The Company has an option to continue the Farm-In until April 30, 2012 by committing to drill a minimum of 100 additional wells under similar terms as in the commitment phase, to earn a minimum of 50 sections of land. Following the commitment and/or option phases, the parties to the agreement can then jointly develop the lands on denser drilling spacing under terms of an operating agreement.

Under the terms of the Farm-In agreement, the Company also has access to drilling opportunities on lands with existing production and access to suspended wellbores with Edmonton Sands potential.

The Company estimates that the average working interest of the 200 well capital commitment will be approximately 80 to 85%, based on partner participation identified to date. Drilling on the farm-in lands commenced on October 25, 2009. The Company expects to have drilled 125 wells on the farm-in lands by spring breakup and to drill an additional 75 wells before the end of 2010 in order to complete the commitment.

The Company has grown its Edmonton Sands land position from 303 gross (179 net) sections in 2007 to 716 gross (403 net) sections currently, including lands acquired through the Farm-In.

As of September 30, 2009 the Company's vertical drilling inventory is as follows:

	<i>Gross</i>	<i>Net</i>
Edmonton Sands (as booked in the GLJ reserves report)	658	357
Edmonton Sands Farm-In lands	1,000	555
Horseshoe Canyon CBM (as booked in the AJM reserves report)	120	23
Rock Creek, Ellerslie and other	25	21
Total	1,803	956

ROYALTY INCENTIVES

On March 3, June 11 and June 25 2009, the Alberta government announced new royalty reduction and fiscal initiatives. There are two measures being implemented that impact the Company. The first measure is a \$200 per meter drilling credit based on activity on Crown lands from April 1, 2009 to March 31, 2011. The Company is committed to drill 125 wells on the Farm-In lands in the upcoming winter season and could potentially generate significant drilling credits through that activity as over 90% of these wells are on Crown lands. This credit is currently expected to take the form of a cash payment of up to 50% of Crown royalties payable from April 1, 2009 to March 31, 2011 based on total depth of wells drilled on Crown land. The Company will likely generate more drilling credits in the next two years than it can use, as the Company's ability to use the credits is capped by the Crown royalties paid during the two year period. The second measure announced was that new wells tied in for production on Crown lands from April 1, 2009 to March 31, 2011 would pay a reduced Crown royalty rate of 5% for the first year of production up to the first 500 MMcf of gas production. Both of these measures are expected to significantly benefit the Company.

CAPITAL BUDGETS

The Board of Directors has approved an amended 2009 capital spending plan of \$33 million, net of expected drilling incentive credits, and a 2010 preliminary budget of \$75 million. The Company expects to spend \$46 million this winter. The Company has awarded bids on its winter Edmonton Sands drilling program and expects drilling and completion costs to be \$230,000 per well compared to \$313,000 per well in the fourth quarter of 2008. The Company will be using the money saved on the drilling and completion operation to build new gas plant and main gathering line infrastructure for the newly drilled wells on the farm-in lands. The infrastructure is expected to service drilling for at least the next two winter drilling programs. The Company is also planning on drilling five deeper liquids rich infill development wells in Westpem targeting the Rock Creek formation and in Sylvan Lake and Willesden Green targeting Ellerslie formations. The Company has also budgeted funds to drill four horizontal multistage frac wells in the Whitemud gas and Cardium light oil formations.

HORIZONTAL MULTISTAGE FRAC OPPORTUNITIES

The Company has identified two high impact opportunities on its lands in Central Alberta employing the latest horizontal multistage frac technology:

Whitemud. This zone is at 550 to 600 meters vertical depth and the horizontal wells are projected to traverse 1,000 meters into the formation. The Whitemud has on average 2.5 Bcf per section of initial gas in place. Currently, the Company has 200 sections of land in this play. Based on a two well per section drilling density, and given success in its initial drilling efforts, the Company could ultimately have up to 400 gross (240 net) horizontal Whitemud drilling locations. The first well is expected to spud in the first quarter of 2010.

Cardium. The Company has 51,000 gross (24,300 net) acres of land in the Cardium light oil horizontal fairway. The Company has highgraded its acreage position to reflect current industry drilling activity immediately offsetting Company lands and has identified 36 gross (20 net) potential locations to drill for Cardium light oil horizontal wells. Offsetting competitors have

quoted initial production rates of 200 to 300 bpd of light oil and capital costs of \$3 million per well. The Company will commence drilling its lands in 2010.

OUTLOOK

The Company has seen significant unprecedented changes in capital, equity, commodity and currency markets in the later part of 2008 and in 2009. The price of natural gas has weakened considerably, as fears of an extended U.S. recession have led to concerns of reduced U.S. industrial use of natural gas. Although there was normal winter weather in North America last winter, Canadian dollar natural gas prices were less than half of last year's average price. Another factor dampening the expectations on natural gas prices is the increased U.S. production of natural gas in 2008 from shale gas plays. United States dry gas production has grown from an average of 52.3 Bcfd in 2007 to an average of 56.4 Bcfd in 2008, and in 2009 has averaged 57.9 Bcfd to August 2009. The United States' natural gas storage is effectively full with 3.8 Tcf of gas in storage. We would expect North American gas supply to be reduced heading into 2010 with the reduced North American drilling activity. However, winter natural gas prices and longer term natural gas prices will be influenced by the extent and duration of the North American recession and the extent and severity of winter weather. Over longer periods of time, natural gas prices will be influenced by the pace of development of U.S. shale gas plays. The Company believes the Edmonton Sands play economics compare favorably with U.S. Shale gas plays.

To date, 2009 has presented challenging conditions in the natural gas business and the Company will continue to manage its business carefully during these times. However, the weak natural gas and crude oil prices also present an opportunity to reduce the cost of doing business and the Company plans to continue to take advantage of that opportunity. The Company is very enthused about its recent Farm-In transaction as well as the new horizontal high impact multistage frac prospects on its land base. Both of these opportunities represent significant upside for the Company's shareholders.

The Company encourages anyone interested in further details on the Company to visit the Company's website at www.andersonenergy.ca.

Brian H. Dau
President & Chief Executive Officer
November 16, 2009

Management's Discussion and Analysis

FOR THE THREE AND NINE MONTHS ENDED SEPTEMBER 30, 2009 AND 2008

The following discussion and analysis of financial results should be read in conjunction with the unaudited consolidated interim financial statements of Anderson Energy Ltd. ("Anderson Energy" or the "Company") for the three and nine months ended September 30, 2009 and the audited consolidated financial statements and management's discussion and analysis of Anderson Energy for the years ended December 31, 2008 and 2007 and is based on information available as of November 13, 2009.

The following information is based on financial statements prepared by management in accordance with Canadian generally accepted accounting principles ("GAAP"). Production and reserves numbers are stated before deducting Crown or lessor royalties.

Included in the discussion and analysis are references to terms commonly used in the oil and gas industry such as funds from operations, finding and development ("F&D") costs, operating netback and barrels of oil equivalent ("BOE"). Funds from operations as used in this report represent cash from operating activities before changes in non-cash working capital and asset retirement expenditures. See "Review of Financial Results – Funds from Operations" for details of this calculation. Funds from operations represent both an indicator of the Company's performance and a funding source for on-going operations. F&D costs measure the cost of reserves additions and are an indicator of the efficiency of capital expended in the period. Operating netback is calculated as oil and gas revenues less royalties and operating expenses and is a measure of the profitability of operations before administrative and financing expenditures. Production volumes and reserves are commonly expressed on a BOE basis whereby natural gas volumes are converted at the ratio of six thousand cubic feet to one barrel of oil. The intention is to sum oil and natural gas measurement units into one basis for improved analysis of results and comparisons with other industry participants. These terms are not defined by Canadian GAAP and therefore are referred to as non-GAAP measures.

All references to dollar values are to Canadian dollars unless otherwise stated.

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

REVIEW OF FINANCIAL RESULTS

Overview. Sales volumes averaged 7,060 BOED for the three months ended September 30, 2009 and 7,780 for the nine months ended September 30, 2009. Funds from operations for the three months ended September 30, 2009 were \$6.6 million, similar to the second quarter of 2009 as significantly lower natural gas prices and lower production volumes were offset by lower royalties and operating costs in the quarter. Funds from operations for the nine months ended September 30, 2009 were \$22.1 million compared to \$66.1 million in the same period of 2008. Significantly lower commodity prices and reduced activity levels have significantly affected cash flows in 2009.

Capital expenditures were \$6.6 million for the three months ended September 30, 2009. During the third quarter of 2009, the Company did not drill any wells. The Company tied in 4 gross (4 net) wells for production, purchased inventory and paid lease acquisition and other pre-drilling costs in anticipation of its upcoming drilling program. The Company commenced drilling again in the fourth quarter of 2009 under its farm-in commitment and plans to drill 100 wells in the fourth quarter of 2009.

Debt, net of working capital, was \$69.8 million at September 30, 2009, a decrease of \$0.1 million from June 30, 2009. The equity financing that closed on May 28, 2009 generated \$56.5 million (net of commission and expenses) and was initially used to pay down bank debt. The availability created in the credit facilities will be used to fund the Company's winter drilling program.

Revenue and Production. Gas sales comprised 86% of Anderson Energy's total oil and gas sales volumes for the three months ended September 30, 2009.

Gas sales were 36.3 MMcfd for the three months ended September 30, 2009 compared to 40.5 MMcfd in the second quarter of 2009 and 38.7 MMcfd in the third quarter of 2008. Due to low natural gas prices, new wells are not being drilled and brought on production to offset natural production decline. Production was also affected by maintenance at Bigoray, Innisfail, Peace River Arch and Sylvan Lake and the shut in of additional wells at Westlock due to low prices. Property dispositions in the fourth quarter of 2008 affected volumes compared to the prior year. Four previously drilled wells at Gilby were tied in over the summer, partially offsetting these declines. Gas sales for the nine months ended September 30, 2009 were 39.7 MMcfd, 1% higher than the nine months ended September 30, 2008 with increases in production early in the year being offset by the effects of the 2008 property dispositions and natural decline.

Oil sales for the three months ended September 30, 2009 averaged 376 bpd compared to 410 bpd in the second quarter of 2009 and 434 bpd for the third quarter of 2008. Oil sales for the nine months ended September 30, 2009 were 410 bpd, 16% lower than the first nine months of 2008. The majority of the Company's oil production is from central and eastern Alberta. Oil sales have declined since the second quarter of 2008 due to property sales in 2008 and workovers being deferred in 2009 due to the lower price environment.

Natural gas liquids sales for the three months ended September 30, 2009 averaged 637 bpd compared to 630 bpd in the second quarter of 2009 and 787 bpd for the third quarter of 2008. Natural gas liquids sales for the nine months ended September 30, 2009 averaged 756 bpd compared to 791 bpd for the first nine months of 2008. Decreases in 2009 are due to lower natural gas production and reductions in ethane sales due to the deep cut facility not operating at Bigoray. The facility is expected to be running again in the fourth quarter of 2009.

Royalty revenue has declined due to lower prices and volumes and the disposition of a royalty interest in 2008. Sulphur revenue has also declined due to low prices. Other revenue includes adjustments to revenue related to periods prior to the acquisition date of properties acquired in 2005.

The following tables outline production revenue, volumes and average sales prices for the periods ended September 30, 2009 and 2008.

OIL AND NATURAL GAS REVENUE

<i>(thousands of dollars)</i>	<i>Three months ended September 30</i>		<i>Nine months ended September 30</i>	
	<i>2009</i>	<i>2008</i>	<i>2009</i>	<i>2008</i>
Natural gas	\$ 9,390	\$ 28,005	\$ 41,672	\$ 93,531
Natural gas economic hedging loss	-	-	-	(1,341)
Oil	2,398	4,478	6,293	13,930
NGL	2,619	5,650	8,402	17,701
Royalty and other	210	1,294	187	2,322
Total	\$ 14,617	\$ 39,427	\$ 56,554	\$ 126,143

PRODUCTION

	<i>Three months ended September 30</i>		<i>Nine months ended September 30</i>	
	<i>2009</i>	<i>2008</i>	<i>2009</i>	<i>2008</i>
Natural gas (Mcf)	36,282	38,703	39,685	39,263
Oil (bpd)	376	434	410	486
NGL (bpd)	637	787	756	791
Total (BOED)	7,060	7,671	7,780	7,820

PRICES

	<i>Three months ended September 30</i>		<i>Nine months ended September 30</i>	
	<i>2009</i>	<i>2008</i>	<i>2009</i>	<i>2008</i>
Natural gas (\$/Mcf)	\$ 2.81	\$ 7.86	\$ 3.85	\$ 8.57
Oil (\$/bbl)	69.30	112.18	56.27	104.70
NGL (\$/bbl)	44.70	78.06	40.73	81.67
Total (\$/BOE)*	\$ 22.50	\$ 55.87	\$ 26.63	\$ 58.87

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

Anderson Energy's average natural gas sales price was \$2.81 per Mcf for the three months ended September 30, 2009, 18% lower than the second quarter of 2009 price of \$3.43 per Mcf and 64% lower than the third quarter of 2008 price of \$7.86 per Mcf. The average gas price was \$3.85 per Mcf for the nine months ended September 30, 2009, 55% lower than the prior year price of \$8.57 per Mcf. In February and March of 2008, the Company had a fixed price natural gas sales contract for 25,000 GJ per day at \$6.89 per GJ. This contract resulted in a \$1.3 million loss in sales dollars. The average gas price for the nine months ended September 30, 2008 was \$8.69 per Mcf before this loss.

Historically, Anderson Energy has sold most of its gas at Alberta spot market prices. In November 2008, the Company began selling approximately 30% of its production at the average monthly index price, and the balance at the average daily index price. By December 2009, the Company will sell most of its gas at the average daily index price. The Company has classified all transportation costs as an offset to gas sales revenue as title transfers prior to transport on the applicable sales pipelines and transportation is being held by and charged by the gas purchasers. The Company has arranged firm service transportation agreements covering approximately 29 MMcfd of natural gas sales for various terms ranging from one to ten years.

Hedging Contracts. The Company currently does not have any hedging contracts. The Company reviews hedging as part of a price management strategy on an ongoing basis.

Royalties. Royalties were 6% of revenue for the three months ended September 30, 2009 compared to 7% for the second quarter of 2009 and 20% for the three months ended September 30, 2008. Royalties were 12% of revenue for the nine months ended September 30, 2009 compared to 22% for the same period in 2008. In the nine months ended September 30, 2009, the Company received \$2.3 million more in gas cost allowance adjustments than had previously been accrued relating to 2008 as a result of changes to the corporate average effective royalty rate and net additions in 2008. Royalty rates would have been 13% for the quarter and 16% for the year to date without these adjustments. On January 1, 2009, the Alberta government's New Royalty Framework came into effect. While royalties increased in some areas, overall, the changes reduced royalties at current production levels and prices due to the Company's focus on shallow gas, lower productivity wells. In addition, when prices and corresponding revenues are lower, gas cost allowance becomes more significant to the overall royalty rate. On March 3, 2009, new royalty initiatives were announced by the Alberta government that focused on future drilling activity. Two measures were announced. The first was a \$200 per meter drilling credit based on drilling activity from April 1, 2009 to March 31, 2011. The credit is capped at 50% of Crown royalties payable from April 1, 2009 to March 31, 2011. The second measure announced was that new wells tied in for production on Crown lands from the period April 1, 2009 to March 31, 2011 would pay a reduced Crown royalty rate of 5% for the first year on up to 500 MMcf of gas production. Both of these measures are expected to significantly benefit the Company.

	<i>Three months ended September 30</i>		<i>Nine months ended September 30</i>	
	<i>2009</i>	<i>2008</i>	<i>2009</i>	<i>2008</i>
<i>Royalties (%)</i>	6%	20%	12%	22%
<i>Royalties (\$/BOE)</i>	\$ 1.24	\$ 11.43	\$ 3.07	\$ 12.76

Operating Expenses. Operating expenses were \$7.72 per BOE for the three months ended September 30, 2009 compared to \$9.58 per BOE in the second quarter of 2009 and \$10.10 per BOE in the third quarter of 2008. Operating expenses were \$9.45 per BOE for the nine months ended September 30, 2009 compared to \$11.19 per BOE in the first nine months of 2008. The Company completed three large plant construction projects in mid 2008 at Willesden Green, Wilson Creek and Buck Lake that helped to reduce reliance on third party processing and lower operating cost per BOE. Approximately 300 BOED of production was shut-in on marginal properties during 2009 due to lower prices which also contributed to the reduction in operating expenses per BOE. The Company has also been negotiating with service providers to reduce costs. The \$7.72 per BOE reported in the third quarter of 2009 reflects the reversal of some prior quarter accruals where the effect of cost reductions had previously been underestimated. This was partially offset by some downhole suspensions and workovers conducted in the quarter. Year to date operating expenses of \$9.45 per BOE are more reflective of current operating expenses.

OPERATING NETBACK

<i>(thousands of dollars)</i>	<i>Three months ended September 30</i>		<i>Nine months ended September 30</i>	
	<i>2009</i>	<i>2008</i>	<i>2009</i>	<i>2008</i>
Revenue	\$ 14,617	\$ 39,427	\$ 56,554	\$ 126,143
Royalties	(804)	(8,070)	(6,522)	(27,344)
Operating expenses	(5,013)	(7,126)	(20,075)	(23,970)
	<u>\$ 8,800</u>	<u>\$ 24,231</u>	<u>\$ 29,957</u>	<u>\$ 74,829</u>
Sales (MBOE)	649.5	705.8	2,123.8	2,142.8
Per BOE				
Revenue	\$ 22.50	\$ 55.87	\$ 26.63	\$ 58.87
Royalties	(1.24)	(11.43)	(3.07)	(12.76)
Operating expenses	(7.72)	(10.10)	(9.45)	(11.19)
	<u>\$ 13.54</u>	<u>\$ 34.34</u>	<u>\$ 14.11</u>	<u>\$ 34.92</u>

General and Administrative Expenses. General and administrative expenses were \$1.4 million or \$2.18 per BOE for the three months ended September 30, 2009 compared to \$1.7 million in the second quarter of 2009 and \$2.0 million for the three months ended September 30, 2008. General and administrative expenses were \$5.1 million or \$2.39 per BOE for the nine months ended September 30, 2009 compared to \$5.4 million or \$2.51 per BOE for the first nine months of 2008. In the second quarter of 2009, the Company took steps to reduce its administration costs including a 5% salary reduction for all staff and the termination of the Employee Stock Savings Plan effective April 1, 2009. Employee lay offs and the termination of certain consultants' contracts resulted in approximately a 15% reduction in head office personnel and a resulting reduction in gross general and administrative expenses. In the third quarter of 2009, the Company conducted a review of its overhead recoveries, resulting in an increase in recoveries in the quarter. Capitalized general and administrative costs are limited to salaries and associated office rent of staff involved in capital activities. With reductions in gross salary costs, capitalized salaries also declined.

<i>(thousands of dollars)</i>	<i>Three months ended September 30</i>		<i>Nine months ended September 30</i>	
	<i>2009</i>	<i>2008</i>	<i>2009</i>	<i>2008</i>
General and administrative (gross)	\$ 2,685	\$ 3,584	\$ 9,008	\$ 9,662
Overhead recoveries	(573)	(487)	(1,284)	(1,394)
Capitalized	(697)	(1,050)	(2,641)	(2,883)
General and administrative (net)	<u>\$ 1,415</u>	<u>\$ 2,047</u>	<u>\$ 5,083</u>	<u>\$ 5,385</u>
General and administrative (\$/BOE)	\$ 2.18	\$ 2.90	\$ 2.39	\$ 2.51
% Capitalized	26%	29%	29%	30%

Stock-Based Compensation. The Company accounts for stock-based compensation plans using the fair value method of accounting. Stock-based compensation costs were \$0.7 million for the third quarter of 2009 (\$0.3 million net of amounts capitalized) versus \$0.4 million (\$0.2 million net of amounts capitalized) in the third quarter of 2008. Stock-based compensation costs were \$1.7 million for the first nine months of 2009 (\$0.9 million net of amounts capitalized) versus \$1.3 million (\$0.7 million net of amounts capitalized) in the first nine months of 2008. The increase is a result of additional stock option grants to new and existing staff in the last half of 2008 and in 2009.

Interest Expense. Interest expense was \$0.8 million for the third quarter of 2009, compared to \$1.1 million in the second quarter of 2009 and \$1.0 million in the third quarter of 2008. For the nine months ended September 30, 2009, interest expense was \$2.9 million compared to \$3.4 million for the comparable period in 2008. Decreasing funds from operations since the second quarter of 2008 had resulted in higher amounts funded through debt financing offset by lower interest rates. On May 28, 2009, the Company issued equity for \$56.5 million (net of commission and expenses), the proceeds of which were initially used to pay down bank loans. Bank loans were \$63 million at September 30, 2009 compared to \$85 million at December 31, 2008 and \$82 million at September 30, 2008.

Depletion and Depreciation. Depletion and depreciation was \$29.09 per BOE or \$18.9 million for the third quarter of 2009 compared to \$28.83 per BOE or \$20.4 million in the second quarter of 2009 and \$20.28 per BOE or \$14.3 million in the third quarter of 2008. Depletion and depreciation was \$28.92 per BOE or \$61.4 million for the first nine months of 2009 compared to \$20.21 per BOE or \$43.3 million in the first nine months of 2008. Depletion and depreciation expense is calculated based on proved reserves only. A decrease in proved reserves in the last quarter of 2008 resulted in an increase in depletion rates per BOE and total dollars in the first nine months of 2009. Lower production resulted in a decrease in the overall expense in the third quarter compared to the second quarter of 2009.

Asset Retirement Obligations. The Company recorded additional asset retirement obligations as a result of well status changes and changes in estimates in the third quarter of 2009. Accretion expense was \$0.5 million for the third quarter of 2009 compared to \$0.5 million in the third quarter of 2008 and was included in depletion and depreciation expense.

Income Taxes. Anderson Energy is not currently taxable. The Company does not anticipate paying current income tax in 2009. Future income tax expense (reduction) has decreased as a percentage of pre-tax earnings (loss) due to reductions in corporate tax rates. The Company has approximately \$307 million in tax pools at September 30, 2009, including approximately \$60 million of Canadian Exploration Expense (CEE) and \$36 million of non-capital losses that expire between 2011 and 2029. The Company expects to be able to fully utilize the losses.

Funds from Operations. Funds from operations for the third quarter of 2009 were \$6.6 million (\$0.04 per share), a 1% decrease from the \$6.7 million (\$0.06 per share) recorded in the second quarter of 2009 and 69% lower than the \$21.2 million (\$0.24 per share) recorded in the third quarter of 2008. Funds from operations for the first nine months of 2009 were \$22.1 million (\$0.19 per share) compared to \$66.1 million (\$0.76 per share) recorded in the same period of the prior year. The decrease in funds from operations in 2009 is a result of lower commodity prices, partially offset by lower costs. Cash from operating activities decreased year over year for similar reasons.

<i>(thousands of dollars)</i>	<i>Three months ended September 30</i>		<i>Nine months ended September 30</i>	
	<i>2009</i>	<i>2008</i>	<i>2009</i>	<i>2008</i>
Cash from operating activities	\$ 6,689	\$ 26,351	\$ 18,459	\$ 71,427
Changes in non-cash working capital	(66)	(5,656)	2,710	(5,956)
Asset retirement expenditures	-	517	938	653
Funds from operations	\$ 6,623	\$ 21,212	\$ 22,107	\$ 66,124

Earnings (loss). The Company reported a loss of \$9.4 million in the third quarter of 2009 compared to a loss of \$10.4 million for the second quarter of 2009 and earnings of \$4.2 million for the third quarter of 2008. The Company reported a loss of \$30.0 million in the first nine months of 2009 compared to earnings of \$14.4 million in the first nine months of 2008. The losses reported in 2009 are due to lower commodity prices and higher depletion and depreciation expense. The Company's funds from operations and earnings are highly sensitive to changes in factors that are beyond its control. An estimate of the Company's sensitivities to changes in commodity prices, exchange rates and interest rates is summarized below:

SENSITIVITIES

<i>(thousands of dollars)</i>	<i>Funds from Operations</i>		<i>Earnings</i>	
	<i>Millions</i>	<i>Per Share</i>	<i>Millions</i>	<i>Per Share</i>
\$0.50/Mcf in price of natural gas	\$ 5.7	\$ 0.06	\$ 4.0	\$ 0.05
US \$5.00/bbl in the WTI crude price	\$ 1.5	\$ 0.02	\$ 1.1	\$ 0.01
US \$0.01 in the US/Cdn exchange rate	\$ 1.2	\$ 0.01	\$ 0.8	\$ 0.01
1% in short-term interest rate	\$ 0.7	\$ 0.01	\$ 0.5	\$ 0.01

This sensitivity analysis was calculated by applying different pricing, interest rate and exchange rate assumptions to the 2008 actual results related to production, prices, royalty rates, operating costs and capital spending.

CAPITAL EXPENDITURES

The Company spent \$22 million on capital expenditures in the nine months ended September 30, 2009. The breakdown of expenditures is shown below:

<i>(thousands of dollars)</i>	<i>Three months ended September 30</i>		<i>Nine months ended September 30</i>	
	<i>2009</i>	<i>2008</i>	<i>2009</i>	<i>2008</i>
Land, geological and geophysical costs	\$ 51	395	\$ 188	\$ 1,044
Acquisitions, net of dispositions	-	18	(54)	(857)
Drilling, completion and recompletion	1,580	17,831	8,460	42,362
Facilities and well equipment	1,226	7,248	7,707	33,265
Capitalized G&A	697	1,050	2,641	2,883
Total finding, development & acquisition expenditures	3,554	26,542	18,942	78,697
Change in compressor and other equipment inventory	3,009	476	3,278	347
Office equipment and furniture	8	50	26	155
Total capital expenditures	6,571	27,068	22,246	79,199
Non-cash asset retirement obligations and capitalized stock-based compensation	(151)	1,451	1,217	3,621
Total cash and non-cash capital additions	\$ 6,420	28,519	\$ 23,463	\$ 82,820

Drilling statistics are shown below:

	<i>Three months ended September 30</i>				<i>Nine months ended September 30</i>			
	<i>2009</i>		<i>2008</i>		<i>2009</i>		<i>2008</i>	
	<i>Gross</i>	<i>Net</i>	<i>Gross</i>	<i>Net</i>	<i>Gross</i>	<i>Net</i>	<i>Gross</i>	<i>Net</i>
Gas	-	-	34	21.2	11	8.3	110	75.2
Oil	-	-	2	2.0	-	-	6	2.9
Dry	-	-	3	2.0	-	-	10	8.1
Total	-	-	39	25.2	11	8.3	126	86.2
Success rate (%)	-	-	92%	92%	100%	100%	92%	91%

The Company did not drill any new wells during the third quarter of 2009. The Company tied in 4 gross (4 net) wells. In the third quarter of 2009, the Company pre-purchased \$3 million of production casing for use in its 2009/2010 winter drilling program and in so doing secured a price reduction of 46% compared to prices in the previous year. Surveying, lease acquisition and other pre-drilling costs of \$1.5 million related to the upcoming winter drilling program were also incurred in the quarter.

CEILING TEST

No impairment was recognized under the ceiling test at September 30, 2009. The future commodity prices used in the ceiling test were based on commodity price forecasts of the Company's independent reserve engineers adjusted for differentials specific to the Company's reserves. Factors used in the ceiling test calculation are disclosed in note 1 of the consolidated interim financial statements for the period ended September 30, 2009.

SHARE INFORMATION

The Company's shares have been listed on the Toronto Stock Exchange since September 7, 2005 under the symbol "AXL". As of November 13, 2009, there were 150.5 million common shares outstanding and 10.4 million stock options outstanding. The following table sets out trading statistics as reported by the Toronto Stock Exchange for the periods indicated.

	<i>Three months ended September 30</i>		<i>Nine months ended September 30</i>	
	<i>2009</i>	<i>2008</i>	<i>2009</i>	<i>2008</i>
High	\$ 1.12	\$ 5.45	\$ 1.48	\$ 5.45
Low	\$ 0.68	\$ 2.16	\$ 0.65	\$ 2.16
Close	\$ 0.97	\$ 2.48	\$ 0.97	\$ 2.48
Volume	46,106,377	13,233,544	95,749,639	66,274,841
Shares outstanding at September 30	150,500,401	87,300,401	150,500,401	87,300,401
Market capitalization at September 30	\$ 145,985,389	\$ 216,504,994	\$ 145,985,389	\$ 216,504,994

LIQUIDITY AND CAPITAL RESOURCES

At September 30, 2009, the Company had outstanding long term bank loans of \$63 million and a working capital deficiency of \$7 million. Based on current credit facilities, the Company has \$30 million or 30% of its credit facilities available for future use.

The Company expects capital expenditures to be approximately \$10 million in the fourth quarter of 2009, net of anticipated drilling credits earned, consisting mainly of drilling on the farm-in lands. Drilling credits are currently estimated to be approximately \$6 to \$8 million. Drilling credits earned are capped at 50% of crown royalties paid between April 1, 2009 and March 31, 2011 and the Company estimates that it will earn more drilling credits than it will be able to claim. These credits will be earned in the fourth quarter of 2009 but are expected to be paid out between 2009 and 2011 as crown royalties are paid. The estimate is highly dependent on commodity prices, production levels, crown royalty rates and gas cost allowance earned over this period. To the extent crown royalties paid are lower or higher, drilling credits will be lower or higher as well.

The Company's need for capital will be both short term and long term in nature. Short-term capital is required to finance accounts receivable and other similar short term assets while the acquisition and development of oil and natural gas properties requires larger amounts of long term capital. At September 30, 2009, the Company has a \$90 million extendible revolving term credit facility and a \$10 million working capital credit facility. The credit facilities have a revolving period ending on July 13, 2010 extendible at the option of the lenders, followed by a term period

with three equal quarterly principal repayments commencing 180 days from the term date. In November 2009, the bank syndicate completed their semi-annual review of the Company's borrowing base, which remains unchanged at \$100 million in aggregate between the two facilities.

On May 28, 2009, the Company issued 63,200,000 common shares at a price of \$0.95 per common share for gross proceeds to Anderson Energy of \$60 million pursuant to a short form prospectus. Net proceeds were \$56.5 million after commission and expenses and were initially used to pay down the Company's bank debt. The Company expects to subsequently use the availability created in the credit facilities to fund its capital program including its commitments under the previously announced Edmonton Sands farm-in.

The Company will continue to fund its ongoing operations from a combination of cash flow, debt, asset dispositions and equity financing as needed. While management is confident that it will be able to continue to fund its ongoing operations, due to the current global economic uncertainties, absolute assurance cannot be given that the funds considered necessary to operate will be available as required.

CONTRACTUAL OBLIGATIONS

The Company enters into various contractual obligations in the course of conducting its operations. These obligations include:

- *Loan agreements* – The reserves-based credit facilities in the amount of \$100 million have a revolving period ending July 13, 2010 extendible at the option of the lenders, followed by a term period with three equal quarterly principal repayments commencing 180 days from the term date.
- *Lease for office space* – This lease expires on November 30, 2012. Future minimum lease payments are expected to be \$0.4 million for the remainder of 2009, \$1.8 million per year in 2010 and 2011, and \$1.6 million in 2012.
- *Firm service transportation commitments* – The Company has entered into firm service transportation agreements for approximately 29 million cubic feet per day of gas sales for various terms expiring between 2009 and 2020. Based on rate schedules announced to date, the payments in each of the next five years and thereafter are estimated to be \$0.4 million in the remainder of 2009, \$1.6 million in 2010, \$1.5 million in 2011, \$1.1 million in 2012, \$0.8 million in 2013 and \$2.0 million thereafter.
- *Farm-in* – On January 30, 2009, the Company announced a farm-in agreement with a large international oil and gas company on lands near its existing core operations. Under the farm-in agreement, the Company has access to 388 gross (205 net) sections of land. During the commitment phase of the transaction, the Company is committed to drill, complete and equip 200 wells to earn an interest in up to 120 sections. The Company is obligated to complete the drilling of the wells on or before December 31, 2010. The commitment is subject to various guarantees. The Company estimates that it will spend approximately \$20 million in 2009 (including expenditures to date) and \$53 million in 2010 on the farm-in, before drilling credits earned. See note 8 to the consolidated interim financial statements for the period ended September 30, 2009 for more details.

INTERNATIONAL FINANCIAL REPORTING STANDARDS (“IFRS”)

In February 2008, the CICA Accounting Standards Board (“AcSB”) confirmed the changeover to International Financial Reporting Standards (“IFRS”) from Canadian Generally Accepted Accounting Principles (“GAAP”) will be required for publicly accountable enterprises for interim and annual financial statements effective for fiscal years beginning on or after January 1, 2011, including comparatives for 2010.

The International Accounting Standards Board (“IASB”) had also issued an exposure draft relating to certain amendments and exemptions to IFRS 1. The IASB announced approval of this amendment in July 2009. The amendment will permit the Company to apply IFRS prospectively by utilizing its current reserves at the transition date to allocate the Company’s full cost pool, with the provision that an impairment test, under IFRS standards, be conducted at the transition date.

Although the amended IFRS 1 standard will provide relief, the changeover to IFRS represents a significant change in accounting standards and the transition from current Canadian GAAP to IFRS will be a significant undertaking that may materially affect the Company’s reported financial position and reported results of operations.

In response, the Company has completed its high-level IFRS changeover plan and established a preliminary timeline for the execution and completion of the conversion project. The changeover plan was determined following a preliminary assessment of the differences between Canadian GAAP and IFRS and the potential effects of IFRS to accounting and reporting processes, information systems, business processes and external disclosures. This assessment has provided insight into what are anticipated to be the most significant areas of difference applicable to the Company.

During the next phase of the project, the Company is performing an in-depth review of the significant areas of difference identified during the preliminary assessment, in order to identify all specific Canadian GAAP and IFRS differences and select ongoing IFRS policies. Key areas addressed will also be reviewed to determine any information technology issues, the impact on internal controls over financial reporting and the impact on business activities including the effect, if any, on covenants and compensation arrangements. External advisors have been retained and will assist management with the project on an as needed basis. Staff training programs have continued in 2009 and will be ongoing as the project unfolds.

The Company will also continue to monitor standards development as issued by the IASB and the AcSB as well as regulatory developments as issued by the Canadian Securities Administrators, which may affect the timing, nature or disclosure of its adoption of IFRS.

CHANGE IN ACCOUNTING POLICY

In May 2009, the Canadian Institute of Chartered Accountants amended Section 3862, “Financial Instruments – Disclosures,” to include additional disclosure requirements about fair value measurement for financial instruments and liquidity risk disclosures. These amendments require a three level hierarchy that reflects the significance of the inputs used in making the fair value measurements. Fair values of assets and liabilities included in Level 1 are determined by

reference to quoted prices in active markets for identical assets and liabilities. Assets and liabilities in Level 2 include valuations using inputs other than quoted prices for which all significant outputs are observable, either directly or indirectly. Level 3 valuations are based on inputs that are unobservable and significant to the overall fair value measurement. These amendments are effective for the Company on December 31, 2009.

CONTROLS AND PROCEDURES

The Chief Executive Officer and the Chief Financial Officer have evaluated and tested the effectiveness of Anderson Energy's disclosure controls and procedures as of September 30, 2009 and have concluded that such disclosure controls and procedures were effective.

The Chief Executive Officer and the Chief Financial Officer have evaluated and tested the design effectiveness of Anderson Energy's internal controls over financial reporting during the three months ended September 30, 2009 and have concluded that these internal controls are designed properly in the preparation of financial statements for external purposes in accordance with Canadian GAAP. There were no material changes in the Company's internal controls over financial reporting during the three months ended September 30, 2009.

Because of inherent limitations, internal controls over financial reporting may not prevent or detect all misstatements, errors or fraud. Control systems, no matter how well designed, only provide reasonable, not absolute, assurance that the objectives of the controls systems are met.

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 credit and liquidity concerns, the U.S. dollar exchange rate, transportation costs, political stability and seasonal and weather related changes to demand. Natural gas prices in particular have weakened on fears of reduced industrial use due to the U.S. recession and increased supply from U.S. natural gas shale plays. The industry is subject to extensive governmental regulation with respect to the environment. Operational risks include well performance, uncertainties inherent in estimating reserves, timing of/ability to obtain drilling licences and other regulatory approvals, ability to obtain equipment, expiration of licences and leases, competition from other producers, sufficiency of insurance, ability to manage growth, reliance on key personnel, third party credit risk and appropriateness of accounting estimates. These risks are described in more detail in the Company's Annual Information Form for the year ended December 31, 2008 filed with Canadian securities regulatory authorities on SEDAR.

The Company anticipates making substantial capital expenditures for the acquisition, exploration, development and production of oil and natural gas reserves in the future. As the Company's revenues may decline as a result of decreased commodity pricing, it may be required to reduce capital expenditures. In addition, uncertain levels of near term industry activity coupled with the present global credit crisis exposes the Company to additional access to capital risk. There can be no assurance that debt or equity financing, or funds generated by operations will be available

or sufficient to meet these requirements or for other corporate purposes or, if debt or equity financing is available, that it will be on terms acceptable to the Company. The inability of the Company to access sufficient capital for its operations could have a material adverse effect on the Company's business, financial condition, results of operations and prospects.

Anderson Energy manages these risks by employing competent professional staff, following sound operating practices and using capital prudently. The Company generates its exploration prospects internally and performs extensive geological, geophysical, engineering, and environmental analysis before committing to the drilling of new prospects. Anderson Energy seeks out and employs new technologies where possible. With the Company's extensive drilling inventory and advance planning, the Company can manage the slower pace of regulatory approvals and the requirements for extensive landowner consultation.

The Company has a formal emergency response plan which details the procedures employees and contractors will follow in the event of an operational emergency. The emergency response plan is designed to respond to emergencies in an organized and timely manner so that the safety of employees, contractors, residents in the vicinity of field operations, the general public and the environment are protected. A corporate safety program covers hazard identification and control on the jobsite, establishes Company policies, rules and work procedures and outlines training requirements for employees and contract personnel.

The Company currently deals with a small number of buyers and sales contracts, and endeavors to ensure that those buyers are an appropriate credit risk. The Company continuously evaluates the merits of entering into fixed price or financial hedge contracts for price management.

The oil and natural gas business is subject to regulation and intervention by governments in such matters as the awarding of exploration and production interests, the imposition of specific drilling obligations, environmental protection controls, control over the development and abandonment of fields (including restrictions on production) and possibly expropriation or cancellation of contract rights. As well, governments may regulate or intervene with respect to prices, taxes, royalties and the exportation of oil and natural gas. Such regulation may be changed from time to time in response to economic or political conditions. The implementation of new regulations or the modification of existing regulations affecting the oil and natural gas industry could reduce demand for oil and natural gas, increase the Company's costs or affect its future opportunities.

The Government of Alberta implemented a new oil and gas royalty framework effective January 2009. The new framework establishes new royalties for conventional oil, natural gas and bitumen that are linked to price and production levels and apply to both new and existing conventional oil and gas activities and oil sands projects. Under the new framework, the formula for conventional oil and natural gas royalties uses a sliding rate formula, dependant on the market price and production volumes. Royalty rates for conventional oil range from 0% to 50%. Natural gas royalty rates range from 5% to 50%.

In November 2008, the Government of Alberta announced that companies drilling new natural gas and conventional oil wells at depths between 1,000 and 3,500 meters, which are spudded between November 19, 2008 and December 31, 2013, will have a one-time option of selecting new transitional royalty rates or the new royalty framework rates. The transition option provides

lower royalties in the initial years of a well's life. For example, under the transition option, royalty rates for natural gas wells will range from 5% to 30%. The election must be made prior to the end of the first calendar month in which the leased substance is produced. All wells using the transitional royalty rates must shift to the new royalty framework rates on January 1, 2014.

On March 3, 2009, the Government of Alberta announced a three-point incentive program. Amendments to the program were announced on June 11 and June 25, 2009. This incentive program includes a drilling credit for new oil and natural gas wells drilled between April 1, 2009 and March 31, 2011, providing a \$200 per meter drilled royalty credit to companies. The credit is limited to 50% of Crown royalties payable over the same period. There is also a new well incentive program that provides a maximum 5% royalty rate for the first 12 months of production from new wells that begin producing oil or natural gas between April 1, 2009 and March 31, 2011 to a maximum of 50,000 barrels of oil or 500 million cubic feet of natural gas. The province of Alberta will also invest \$30 million in a fund committed to abandonment and reclamation projects where there is no legally responsible or financially able party to deal with the clean-up of inactive wells.

In addition, the Alberta government has announced that it will be conducting a competitiveness review covering all components of conventional operations including fiscal and tax aspects, availability of labour and other costs. The Alberta government has promised to complete the review in 2009.

The changes to the royalty regime in the Province of Alberta are subject to certain risks and uncertainties. There may be modifications introduced to the royalty structure and such changes may be adverse to the business of the Company. There can be no assurance that the Government of Alberta nor the Government of Canada will not adopt new royalty regimes which may render the Company's projects uneconomic or otherwise adversely affect the business of the Company.

The oil and natural gas industry is currently subject to environmental regulations pursuant to a variety of provincial and federal legislation. Such legislation provides for restrictions and prohibitions on the release or emission of various substances produced in association with certain oil and gas industry operations. Such legislation may also impose restrictions and prohibitions on water use or processing in connection with certain oil and gas operations. In addition, such legislation requires that well and facility sites be abandoned and reclaimed to the satisfaction of provincial authorities. Compliance with such legislation can require significant expenditures and a breach of such requirements may result, amongst other things in suspension or revocation of necessary licenses and authorizations, civil liability for pollution damage, and the imposition of material fines and penalties.

BUSINESS PROSPECTS

The Company believes it has an excellent future drilling inventory with several years of development drilling locations in the Edmonton Sands and Horseshoe Canyon Coal Bed Methane resource plays and the West Pembina Rock Creek play. The Company has also identified high impact multistage frac horizontal drilling opportunities targeting the Whitemud gas formation and Cardium oil in Central Alberta.

During periods of price weakness, the Company's business strategy is to grow its assets and reduce its costs. The Company previously announced a significant farm-in transaction in the Edmonton Sands Project Area. Anderson Energy believes the transaction will deliver significant benefits to the Company and will define it as the major Edmonton Sands resource player in Central Alberta. Anderson Energy drilled 11 Edmonton Sands wells in the first nine months of 2009 and tied in 39 Edmonton Sands wells. This is less than originally planned in order to maintain the Company's financial flexibility and to accommodate the drilling program on the farm-in lands later in the year. A minimum of 75 Edmonton Sands locations are committed to be drilled in the last quarter of 2009 on the farm-in lands. The Company anticipates drilling 100 wells on this commitment during the fourth quarter of 2009. The equity financing completed during the second quarter of 2009 and the Company's available bank lines provide the Company with the financial flexibility to take advantage of the opportunities provided by the farm-in.

The Company expects average production in 2009 to be approximately 7,500 to 7,600 BOED and in 2010 to be 8,000 to 8,500 BOED. Risks associated with this guidance include continued low prices which may restrict capital spending, gas plant capacity, gas plant turnaround duration, regulatory issues, weather problems and access to industry services.

QUARTERLY INFORMATION

The following table provides financial and operating results for the last eight quarters. Earnings were negatively impacted in the fourth quarter of 2008 by a \$35.4 million charge for impairment of goodwill. Prices have been declining since the second quarter of 2008, which decreased funds from operations and earnings in the most recent quarters.

SELECTED QUARTERLY INFORMATION

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

	Q3 2009	Q2 2009	Q1 2009	Q4 2008
Oil and gas revenue before royalties	\$ 14,617	\$ 17,508	\$ 24,429	\$ 30,102
Funds from operations	\$ 6,623	\$ 6,692	\$ 8,792	\$ 13,204
Funds from operations per share				
Basic	\$ 0.04	\$ 0.06	\$ 0.10	\$ 0.15
Diluted	\$ 0.04	\$ 0.06	\$ 0.10	\$ 0.15
Earnings (loss) before goodwill impairment	\$ (9,432)	\$ (10,410)	\$ (10,159)	\$ (5,865)
Earnings (loss) before goodwill impairment per share				
Basic	\$ (0.06)	\$ (0.09)	\$ (0.12)	\$ (0.07)
Diluted	\$ (0.06)	\$ (0.09)	\$ (0.12)	\$ (0.07)
Earnings (loss)	\$ (9,432)	\$ (10,410)	\$ (10,159)	\$ (41,229)
Earnings (loss) per share				
Basic	\$ (0.06)	\$ (0.09)	\$ (0.12)	\$ (0.47)
Diluted	\$ (0.06)	\$ (0.09)	\$ (0.12)	\$ (0.47)
Capital expenditures, including acquisitions net of dispositions	\$ 6,571	\$ 2,130	\$ 13,545	\$ 27,470
Cash from operating activities	\$ 6,689	\$ 2,472	\$ 9,298	\$ 11,261
Daily sales				
Natural gas (Mcf)	36,282	40,495	42,344	38,090
Liquids (bpd)	1,013	1,040	1,448	1,341
Barrels of oil equivalent (BOED)	7,060	7,789	8,505	7,689
Average prices				
Natural gas (\$/Mcf)	\$ 2.81	\$ 3.43	\$ 5.15	\$ 6.76
Liquids (\$/bbl)	\$ 53.84	\$ 49.00	\$ 38.69	\$ 48.49
BOE (\$/BOE)*	\$ 22.50	\$ 24.70	\$ 31.91	\$ 42.55

	Q3 2008	Q2 2008	Q1 2008	Q4 2007
Oil and gas revenue before royalties	\$ 39,427	\$ 49,021	\$ 37,695	\$ 27,775
Funds from operations	\$ 21,212	\$ 27,321	\$ 17,591	\$ 12,564
Funds from operations per share				
Basic	\$ 0.24	\$ 0.31	\$ 0.20	\$ 0.14
Diluted	\$ 0.24	\$ 0.31	\$ 0.20	\$ 0.14
Earnings (loss)	\$ 4,160	\$ 8,509	\$ 1,696	\$ 4,867
Earnings (loss) per share				
Basic	\$ 0.05	\$ 0.10	\$ 0.02	\$ 0.06
Diluted	\$ 0.05	\$ 0.10	\$ 0.02	\$ 0.06
Capital expenditures, including acquisitions net of dispositions	\$ 27,068	\$ 16,772	\$ 35,359	\$ 30,300
Cash from operating activities	\$ 26,351	\$ 27,660	\$ 17,416	\$ 11,110
Daily sales				
Natural gas (Mcf)	38,703	39,881	39,210	35,672
Liquids (bpd)	1,221	1,265	1,345	1,150
Barrels of oil equivalent (BOED)	7,671	7,912	7,879	7,095
Average prices				
Natural gas (\$/Mcf)	\$ 7.86	\$ 10.26	\$ 7.55	\$ 6.09
Liquids (\$/bbl)	\$ 90.19	\$ 97.61	\$ 83.91	\$ 72.28
BOE (\$/BOE)*	\$ 55.87	\$ 68.08	\$ 52.57	\$ 42.55

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

ADVISORY

Certain information regarding Anderson Energy Ltd. in this news release including, without limitation, management's assessment of future plans and operations, benefits and valuation of the Farm-In described herein, number of locations in drilling inventory and wells to be drilled, timing and location of drilling and tie-in of wells and the costs thereof, productive capacity of the wells, timing of and construction of facilities, expected production rates, dates of commencement of production, amount of capital expenditures and timing thereof, value of undeveloped land, extent of reserves additions, ability to attain cost savings, drilling program success, impact of changes to the royalty regime applicable to the Company, commodity price outlook and general economic outlook may constitute forward-looking statements under applicable securities laws and necessarily involve risks and assumptions made by management of the Company including, without limitation, risks associated with oil and gas exploration, development, exploitation, production, marketing and transportation, loss of markets, volatility of commodity prices, currency fluctuations, imprecision of reserves estimates, environmental risks, competition from other producers, inability to retain drilling rigs and other services, capital expenditure costs, including drilling, completion and facilities costs, unexpected decline rates in wells, wells not performing as expected, incorrect assessment of the value of acquisitions and farm-ins, failure to realize the anticipated benefits of acquisitions and farm-ins, delays resulting from or inability to obtain required regulatory approvals and ability to access sufficient capital from internal and external sources. As a consequence, actual results may differ materially from those anticipated in the forward-looking statements. Readers are cautioned that the foregoing list of factors is not exhaustive. Additional information on these and other factors that could affect Anderson Energy's operations and financial results are included in reports on file with Canadian securities regulatory authorities and may be accessed through the SEDAR website (www.sedar.com) and at Anderson Energy's website (www.andersonenergy.ca).

Furthermore, the forward-looking statements contained in this news release are made as at the date of this news release and Anderson Energy 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.

Disclosure provided herein in respect of barrels of oil equivalent (BOE) may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 Mcf: 1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

ANDERSON ENERGY LTD.

Consolidated Balance Sheets

(Stated in thousands of dollars)
(Unaudited)

	September 30, 2009	December 31, 2008
ASSETS		
Current assets:		
Cash and cash equivalents	\$ -	\$ 1
Accounts receivable and accruals <i>(note 7)</i>	11,456	28,960
Prepaid expenses and deposits	4,082	2,692
	<u>15,538</u>	<u>31,653</u>
Property, plant and equipment <i>(note 1)</i>	474,205	511,880
	<u>\$ 489,743</u>	<u>\$ 543,533</u>
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable and accruals	\$ 22,683	\$ 71,619
Bank loans <i>(note 2)</i>	62,674	85,314
Asset retirement obligations <i>(note 3)</i>	32,032	30,820
Future income taxes	33,608	46,168
	<u>150,997</u>	<u>233,921</u>
Shareholders' equity:		
Share capital <i>(note 4)</i>	391,637	334,176
Contributed surplus <i>(note 4)</i>	5,674	4,000
Deficit	<u>(58,565)</u>	<u>(28,564)</u>
	338,746	309,612
Commitments <i>(note 8)</i>		
	<u>\$ 489,743</u>	<u>\$ 543,533</u>

See accompanying notes to the consolidated financial statements.

ANDERSON ENERGY LTD.

Consolidated Statements of Operations, Comprehensive Income (Loss) and Retained Earnings (Deficit)

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

	Three months ended September 30,		Nine months ended September 30,	
	2009	2008	2009	2008
REVENUES				
Oil and gas sales	\$ 14,617	\$ 39,427	\$ 56,554	\$ 126,143
Royalties	(804)	(8,070)	(6,522)	(27,344)
Interest income	18	8	146	53
	<u>13,831</u>	<u>31,365</u>	<u>50,178</u>	<u>98,852</u>
EXPENSES				
Operating	5,013	7,126	20,075	23,970
General and administrative	1,415	2,047	5,083	5,385
Stock-based compensation	339	232	852	692
Interest and other financing charges	780	980	2,913	3,373
Depletion, depreciation and accretion	<u>19,436</u>	<u>14,840</u>	<u>63,176</u>	<u>44,752</u>
	<u>26,983</u>	<u>25,225</u>	<u>92,099</u>	<u>78,172</u>
Earnings (loss) before taxes	(13,152)	6,140	(41,921)	20,680
Future income tax expense (reduction)	<u>(3,720)</u>	<u>1,980</u>	<u>(11,920)</u>	<u>6,315</u>
Earnings (loss) and comprehensive income (loss) for the period	(9,432)	4,160	(30,001)	14,365
Retained earnings (deficit), beginning of period	<u>(49,133)</u>	<u>8,505</u>	<u>(28,564)</u>	<u>(1,700)</u>
Retained earnings (deficit), end of period	\$ <u>(58,565)</u>	\$ <u>12,665</u>	\$ <u>(58,565)</u>	\$ <u>12,665</u>
Earnings (loss) per share (note 4)				
Basic	\$ (0.06)	\$ 0.05	\$ (0.26)	\$ 0.16
Diluted	\$ (0.06)	\$ 0.05	\$ (0.26)	\$ 0.16

See accompanying notes to the consolidated financial statements.

ANDERSON ENERGY LTD.

Consolidated Statements of Cash Flows

(Stated in thousands of dollars)
(Unaudited)

	Three months ended September 30,		Nine months ended September 30,	
	2009	2008	2009	2008
CASH PROVIDED BY (USED IN)				
OPERATIONS				
Earnings (loss) for the period	\$ (9,432)	\$ 4,160	\$ (30,001)	\$ 14,365
Items not involving cash:				
Depletion, depreciation and accretion	19,436	14,840	63,176	44,752
Future income tax expense (reduction)	(3,720)	1,980	(11,920)	6,315
Stock-based compensation	339	232	852	692
Asset retirement expenditures	-	(517)	(938)	(653)
Changes in non-cash working capital:				
Accounts receivable and accruals	1,149	7,532	5,859	(47)
Prepaid expenses and deposits	(83)	(92)	(1,337)	(615)
Accounts payable and accruals	<u>(1,000)</u>	<u>(1,784)</u>	<u>(7,232)</u>	<u>6,618</u>
	6,689	26,351	18,459	71,427
FINANCING				
Increase (decrease) in bank loans	(5,830)	1,027	(22,640)	14,209
Issue of common shares, net of issue costs	-	-	56,538	25
Changes in non-cash working capital:				
Accounts payable and accruals	<u>(159)</u>	<u>-</u>	<u>161</u>	<u>-</u>
	(5,989)	1,027	34,059	14,234
INVESTMENTS				
Additions to property, plant and equipment	(6,571)	(27,050)	(22,300)	(80,056)
Proceeds on disposition (acquisition) of properties	-	(18)	54	857
Changes in non-cash working capital:				
Accounts receivable and accruals	1,435	(4,075)	11,645	3,300
Prepaid expenses and deposits	13	27	(53)	147
Accounts payable and accruals	<u>(3,715)</u>	<u>3,621</u>	<u>(41,865)</u>	<u>(9,910)</u>
	<u>(8,838)</u>	<u>(27,495)</u>	<u>(52,519)</u>	<u>(85,662)</u>
Decrease in cash	(8,138)	(117)	(1)	(1)
Cash and cash equivalents, beginning of period	<u>8,138</u>	<u>118</u>	<u>1</u>	<u>2</u>
Cash and cash equivalents, end of period	\$ -	\$ 1	\$ -	\$ 1

See note 6 for additional cash information.

See accompanying notes to the consolidated financial statements.

ANDERSON ENERGY LTD.

Notes to the Consolidated Financial Statements

THREE AND NINE MONTHS ENDED SEPTEMBER 30, 2009 AND 2008

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

Anderson Energy Ltd. (“Anderson Energy” or the “Company”) was incorporated under the laws of the province of Alberta on January 30, 2002. Anderson Energy is engaged in the acquisition, exploration and development of oil and gas properties in western Canada. These interim consolidated financial statements have been prepared following the same accounting policies and methods of computation as the consolidated financial statements for the year ended December 31, 2008. The disclosures included below are incremental to those included with the annual consolidated financial statements. These interim consolidated financial statements should be read in conjunction with the consolidated financial statements and the notes thereto for the year ended December 31, 2008.

Change in accounting policy. In May 2009, the Canadian Institute of Chartered Accountants amended Section 3862, “Financial Instruments – Disclosures,” to include additional disclosure requirements about fair value measurement for financial instruments and liquidity risk disclosures. These amendments require a three level hierarchy that reflects the significance of the inputs used in making the fair value measurements. Fair values of assets and liabilities included in Level 1 are determined by reference to quoted prices in active markets for identical assets and liabilities. Assets and liabilities in Level 2 include valuations using inputs other than quoted prices for which all significant outputs are observable, either directly or indirectly. Level 3 valuations are based on inputs that are unobservable and significant to the overall fair value measurement. These amendments are effective for the Company on December 31, 2009.

1. PROPERTY, PLANT AND EQUIPMENT

	<i>September 30, 2009</i>	<i>December 31, 2008</i>
Cost	\$ 710,166	\$ 686,420
Less accumulated depletion and depreciation	<u>(235,961)</u>	<u>(174,540)</u>
<u>Net book value</u>	<u>\$ 474,205</u>	<u>\$ 511,880</u>

At September 30, 2009, unproved property costs of \$8.5 million (December 31, 2008 – \$8.5 million) have been excluded from the full cost pool for depletion and depreciation calculations. Future development costs of proved, undeveloped reserves of \$204.5 million (December 31, 2008 – \$204.7 million) have been included in the depletion and depreciation calculation.

For the nine months ended September 30, 2009, \$3.5 million (September 30, 2008 – \$3.6 million) of general and administrative costs including \$0.8 million (September 30, 2008 – \$0.6 million) of stock-based compensation costs were capitalized. The future tax liability of \$0.3 million (September 30, 2008 – \$0.2 million) associated with the capitalized stock-based compensation has also been capitalized. For the three months ended September 30, 2009, \$1.0 million (September 30, 2008 – \$1.3 million) of general and administrative costs including

1. PROPERTY, PLANT AND EQUIPMENT *(Continued)*

\$0.3 million (September 30, 2008 – \$0.2 million) of stock-based compensation costs were capitalized. Capitalized general and administrative costs consist of salaries and associated office rent of staff involved in capital activities.

No impairment was recognized under the ceiling test at September 30, 2009. The future commodity prices used in the ceiling test were based on commodity price forecasts of the Company's independent reserve engineers adjusted for differentials specific to the Company's reserves. Factors used in the ceiling test calculation are as follows:

	<i>AECO Gas Price (\$Cdn/Mcf)</i>	<i>WTI Cushing (\$US/bbl)</i>	<i>Exchange rate (US\$/Cdn)</i>
2009 Q4	5.43	70.00	0.92
2010	6.36	74.00	0.92
2011	6.77	77.00	0.93
2012	7.10	82.00	0.93
2013	7.23	88.00	0.94
2014	7.68	93.85	0.95
2015	8.47	95.73	0.95
2016	8.94	97.64	0.95
<u>Thereafter 2%</u>			

After 2016, only inflationary growth of 2% per year was considered for prices. Natural gas liquids prices were tied to crude oil prices based on historical trends and analysis. Exchange rates were expected to remain consistent from 2016 forward.

2. BANK LOANS

At September 30, 2009, the Company has a \$90 million extendible, revolving term credit facility and a \$10 million working capital credit facility (the "Facilities") with a syndicate of Canadian banks. The reserves-based Facilities have a revolving period ending on July 13, 2010, extendible at the option of the lenders, followed by a term period with three equal quarterly principal repayments commencing 180 days from the term date. The average effective interest rate on advances in 2009 for the nine month period was 4.2% (September 30, 2008 – 5.1%).

Advances under the Facilities can be drawn in either Canadian or U.S. funds and bear interest at the bank's prime lending rate, bankers' acceptance or LIBOR loan rates plus applicable margins. The margins vary depending on the borrowing option used and the Company's financial ratios. At September 30, 2009 there were no advances in U.S. funds.

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

2. BANK LOANS *(Continued)*

The available lending limits of the Facilities are reviewed semi-annually and are based on the bank syndicate's interpretations of the Company's reserves and future commodity prices. The most recent semi-annual review was completed in November 2009 and the borrowing base of \$100 million was re-confirmed.

3. ASSET RETIREMENT OBLIGATIONS

The Company estimates the total undiscounted cash flows required to settle its asset retirement obligations is approximately \$67.0 million (December 31, 2008 – \$63.4 million), including expected inflation of 2% (December 31, 2008 – 2%) per annum. The majority of the costs will be incurred between 2009 and 2020. A credit adjusted risk-free rate of 8% to 10% (December 31, 2008 – 8% to 10%) was used to calculate the fair value of the asset retirement obligations. A reconciliation of the asset retirement obligations is provided below:

	<i>September 30, 2009</i>	<i>December 31, 2008</i>
Balance, beginning of period	\$ 30,820	\$ 24,526
Liabilities incurred during period	291	3,951
Liabilities settled in period	(938)	(1,132)
Liabilities settled on disposition	-	(1,234)
Change in estimate	104	2,770
Accretion expense	1,755	1,939
Balance, end of period	<u>\$ 32,032</u>	<u>\$ 30,820</u>

4. SHARE CAPITAL AND CONTRIBUTED SURPLUS

Authorized share capital. The Company is authorized to issue an unlimited number of common and preferred shares. The preferred shares may be issued in one or more series.

Issued share capital.

	<i>Number of Common Shares</i>	<i>Amount</i>
Balance at December 31, 2007	87,294,401	\$ 334,147
Stock options exercised	6,000	25
Transferred from contributed surplus on stock option exercise	-	4
Balance at December 31, 2008	87,300,401	\$ 334,176
Issued pursuant to prospectus ⁽¹⁾	63,200,000	60,040
Share issue costs	-	(3,502)
Tax effect of share issue costs	-	923
Balance at September 30, 2009	<u>150,500,401</u>	<u>\$ 391,637</u>

(1) Includes 4,992,034 common shares issued to management and directors and 3,377,966 common shares issued to family of management and directors for total gross proceeds of \$8.0 million.

4. SHARE CAPITAL AND CONTRIBUTED SURPLUS (Continued)

Stock options. The Company has an employee stock option plan under which employees, directors and consultants are eligible to receive grants. The exercise price of stock options equals the weighted average trading price of the Company's shares for the five trading days prior to the date of the grant. Options have terms of either five or ten years and vest equally over a three year period starting on the first anniversary date of the grant. Changes in the number of options outstanding during the nine months ended September 30, 2009 and year ended December 31, 2008 are as follows:

	<i>Number of options</i>		<i>Weighted average exercise price</i>
Balance at December 31, 2007	6,297,306	\$	4.65
Granted	1,468,300		3.21
Exercised	(6,000)		4.13
Expirations	(48,800)		4.80
Forfeitures	(115,950)		4.28
Balance at December 31, 2008	7,594,856	\$	4.37
Granted	3,280,200		0.79
Expirations	(99,400)		7.93
Forfeitures	(249,000)		3.79
Balance at September 30, 2009	10,526,656	\$	3.24
Exercisable at September 30, 2009	5,920,239	\$	4.56

<i>Range of exercise prices</i>	<i>Options outstanding</i>			<i>Options exercisable</i>	
	<i>Number of options</i>	<i>Weighted average exercise price</i>	<i>Weighted average remaining life (years)</i>	<i>Number of options</i>	<i>Weighted average exercise price</i>
\$0.79 to \$0.99	3,226,200	\$ 0.79	4.9	-	\$ -
\$1.00 to \$1.50	53,100	1.05	4.3	-	-
\$2.26 to \$3.35	935,700	2.68	4.0	300,900	2.69
\$3.36 to \$5.00	5,127,656	4.01	2.8	4,441,339	4.00
\$5.01 to \$7.50	543,000	6.15	1.7	537,000	6.16
\$7.51 to \$9.01	641,000	7.93	1.1	641,000	7.93
Total at September 30, 2009	10,526,656	\$ 3.24	3.4	5,920,239	\$ 4.56

The fair value of the options issued during the nine months ended September 30, 2009 was \$0.42 per option (September 30, 2008 – \$1.63 per option). The weighted average assumptions used in arriving at the values were: a risk-free interest rate of 2.4% (September 30, 2008 – 3.2%), expected option life of five years (September 30, 2008 – five years), expected volatility of 60% (September 30, 2008 – 56%) and a dividend yield of 0% (September 30, 2008 – 0%).

4. SHARE CAPITAL AND CONTRIBUTED SURPLUS (Continued)

Per share amounts. During the nine months ended September 30, 2009 there were 116,469,632 average shares outstanding (September 30, 2008 – 87,297,270). On a diluted basis, there were 116,469,632 weighted average shares outstanding (September 30, 2008 – 87,399,611) after giving effect to dilutive stock options. During the three months ended September 30, 2009 there were 150,500,401 weighted average shares outstanding (September 30, 2008 – 87,300,401). On a diluted basis, there were 150,500,401 weighted average shares outstanding (September 30, 2008 – 87,300,401) after giving effect to dilutive stock options. At September 30, 2009, there were 10,526,656 options that were anti-dilutive (September 30, 2008 – 7,597,056).

Contributed surplus

	<i>Amount</i>
Balance at December 31, 2007	\$ 2,005
Stock-based compensation	1,999
Transferred from contributed surplus on stock option exercise	(4)
Balance at December 31, 2008	\$ 4,000
Stock-based compensation	1,674
Balance at September 30, 2009	\$ 5,674

5. MANAGEMENT OF CAPITAL STRUCTURE

The Company manages its capital structure and makes adjustments to it in the light of changes in economic conditions and the risk characteristics of the underlying petroleum and natural gas assets. The Company's capital structure includes shareholders' equity of \$338.7 million, long term bank loans of \$62.7 million and the working capital deficiency of \$7.1 million. In order to maintain or adjust the capital structure, the Company may from time to time issue shares, seek additional debt financing and adjust its capital spending to manage current and projected debt levels.

Consistent with other companies in the oil and gas sector, Anderson Energy monitors capital based on the ratio of total debt to funds from operations. This ratio is calculated by dividing total debt at the end of the period (comprised of the working capital deficiency and outstanding bank loans) by the annualized current quarter funds from operations (cash flow from operating activities before changes in non-cash working capital and asset retirement expenditures). This ratio may increase at certain times as a result of acquisitions, the timing of capital expenditures and market conditions. In order to facilitate the management of this ratio, the Company prepares annual capital expenditure budgets, which are updated as necessary depending on varying factors including current and forecast crude oil and natural gas prices, capital deployment and general industry conditions. The annual and updated budgets are approved by the Board of Directors.

5. MANAGEMENT OF CAPITAL STRUCTURE *(Continued)*

	<i>September 30, 2009</i>	<i>December 31, 2008</i>
Bank loans	\$ 62,674	\$ 85,314
Current liabilities	22,683	71,619
Current assets	(15,538)	(31,653)
Total debt	\$ 69,819	\$ 125,280
Cash from operating activities in quarter	\$ 6,689	\$ 11,261
Changes in non-cash working capital	(66)	1,464
Asset retirement expenditures	-	479
Funds from operations in quarter	\$ 6,623	\$ 13,204
Annualized current quarter funds from operations	\$ 26,492	\$ 52,816
Total debt to funds from operations	2.6	2.4

At September 30, 2009, the Company's total debt to annualized funds from operations was 2.6. During the fourth quarter of 2008 and the first nine months of 2009, commodity prices decreased significantly, adversely affecting the Company's cash flow. Management has restricted capital and administrative spending until commodity prices recover. On May 28, 2009, the Company closed an equity financing for net proceeds of \$56.5 million (note 4) and renewed its banking facilities at an available limit of \$100 million (note 2) to provide funding for its farm-in commitments (note 8) and other capital spending planned for the rest of the year.

The Company's share capital is not subject to external restrictions, however, the banking facilities are based on the value of petroleum and natural gas reserves. Anderson Energy has not paid or declared any dividends since the date of incorporation and does not contemplate doing so in the foreseeable future.

6. CASH PAYMENTS

The following cash payments were made (received):

	<i>September 30, 2009</i>	<i>September 30, 2008</i>
Interest paid	\$ 2,198	\$ 2,708
Interest received	(147)	(56)

7. FINANCIAL INSTRUMENTS AND FINANCIAL RISK MANAGEMENT

The Company's financial instruments include cash and cash equivalents, accounts receivable and accruals, deposits, accounts payable and accruals and bank loans. The carrying value of accounts receivable and accruals, deposits and accounts payable and accruals approximate their fair value due to their demand nature or relatively short periods to maturity. The fair value of cash equivalents and bank loans approximate their carrying value as they bear interest at a floating rate.

The Company has exposure to credit risk, liquidity risk and market risk as a result of its use of financial instruments.

Credit risk. Credit risk is the risk of financial loss to the Company if a customer or counterparty to a financial instrument fails to meet its contractual obligations. As at September 30, 2009, the maximum credit exposure is the carrying amount of the accounts receivable and accruals of \$11.5 million (December 31, 2008 – \$29.0 million). As at September 30, 2009, the Company's receivables consisted of \$5.6 million (December 31, 2008 – \$17.3 million) from joint venture partners and other trade receivables and \$5.9 million (December 31, 2008 – \$11.7 million) of revenue accruals and other receivables from petroleum and natural gas marketers. Of the \$5.9 million of revenue accruals and receivables from petroleum and natural gas marketers, \$4.7 million was received on or about October 25, 2009. The balance is expected to be received in subsequent months through joint venture billings from partners.

The Company's allowance for doubtful accounts as at September 30, 2009 is \$1.6 million. The Company provided for an additional \$0.2 million in allowance and did not write-off any receivables during the nine months ended September 30, 2009. The Company would only choose to write-off a receivable balance (as opposed to providing an allowance) after all reasonable avenues of collection had been exhausted.

As at September 30, 2009 the Company considers its receivables to be aged as follows:

<i>Aging</i>	<i>September 30, 2009</i>
Not past due	\$ 10,594
Past due by less than 120 days	805
Past due by more than 120 days	57
Total	<u>\$ 11,456</u>

These amounts are before offsetting amounts owing to joint venture partners that are included in accounts payable and accrued liabilities.

Liquidity risk. Liquidity risk is the risk that the Company will incur difficulties meeting its financial obligations as they are due.

7. FINANCIAL INSTRUMENTS AND FINANCIAL RISK MANAGEMENT *(Continued)*

The following are the contractual maturities of financial liabilities and associated interest payments as at September 30, 2009:

<i>Financial Liabilities</i>	<i>< 1 Year</i>	<i>1 -2 Years</i>
Accounts payable and accruals	\$ 22,683	\$ -
Bank loans – principal	-	62,674
Total	\$ 22,683	\$ 62,674

Please refer to note 8 for additional details on commitments.

Market risk. Market risk consists of currency risk, commodity price risk and interest rate risk.

Currency risk. Foreign currency exchange rate risk is the risk that the fair value or future cash flows will fluctuate as a result of changes in foreign exchange rates.

The Company had no outstanding forward exchange rate contracts in place at September 30, 2009 or December 31, 2008.

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.

No commodity price contracts were entered into during the nine months ended September 30, 2009 and there were no commodity price risk contracts outstanding at September 30, 2009 or December 31, 2008.

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 Company is exposed to interest rate fluctuations on its bank debt which bears interest at a floating rate. For the nine months ended September 30, 2009, if interest rates had been 1% lower with all other variables held constant, earnings for the period would have been \$0.4 million (September 30, 2008 – \$0.4 million) higher, due to lower interest expense. An equal and opposite impact would have occurred had interest rates been higher by the same amounts.

The Company had no interest rate swap or financial contracts in place at September 30, 2009 or December 31, 2008.

8. COMMITMENTS

On January 29, 2009, the Company executed a farm-in agreement with a large international oil and gas company (the "Farmor") on lands near its existing core operations. Under the farm-in agreement, the Company has access to 388 gross (205 net) sections of land. During the commitment phase of the transaction, the Company is committed to drill, complete and equip 200 wells to earn an interest in up to 120 sections. The Company is obligated to complete the drilling of the wells on or before December 31, 2010. The Company's equipping obligation is up to, but does not include, multi-well gathering systems downstream of field compression and/or gas plants. The Company has an option to continue the farm-in transaction until April 30, 2012 by committing to drill a minimum of 100 additional wells under similar terms as in the commitment phase to earn a minimum of 50 sections of land. Following the commitment and/or option phases, the parties to the agreement can then jointly develop the lands on denser drilling spacing under terms of an operating agreement.

The Company estimates that the average working interest of the 200 well capital commitment will be approximately 80 to 85%, based on partner participation identified to date and expects to commence drilling in the fourth quarter of 2009. The Company's initial commitment is to drill 75 wells by December 31, 2009, a further 50 wells by April 30, 2010 and a further 75 wells by December 31, 2010. The Company earns its interest in each well as the well is put on production. After December 31, 2009 and April 30, 2010 respectively, the Farmor has the ability to request a letter of credit from the Company in the amount of \$550,000 per well not drilled under the minimum commitment at that date. At December 31, 2010, the \$550,000 penalty is payable for each well not drilled, subject to certain reductions due to unavoidable events beyond the Company's control and rights of first refusal. The Company estimates that it will spend approximately \$20 million in 2009 (including expenditures to date) and \$53 million in 2010 on the farm-in, before drilling credits earned.

The Company has entered into an agreement to lease office space until November 30, 2012. Future minimum lease payments are expected to be \$0.4 million for the remainder of 2009, \$1.8 million in 2010 and 2011 and \$1.6 million in 2012.

The Company entered into firm service transportation agreements for approximately 29 million cubic feet per day of gas sales in central Alberta for various terms between 2009 and 2020. Based on rate schedules announced to date, the payments in each of the next five years and thereafter are estimated as follows:

	<i>Committed volume (Mmcf/d)</i>	<i>Committed amount</i>
2009 Q4	24	\$ 398
2010	25	\$ 1,621
2011	21	\$ 1,464
2012	13	\$ 1,070
2013	7	\$ 789
<u>Thereafter</u>	<u>26</u>	<u>\$ 2,037</u>

Corporate Information

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Member of:

- (1) Audit Committee
- (2) Compensation & Corporate Governance Committee
- (3) Reserves Committee

Auditors

KPMG LLP
Calgary, Alberta

Independent Engineers

GLJ Petroleum Consultants

Legal Counsel

Bennett Jones LLP

Registrar & Transfer Agent

Valiant Trust Company

Stock Exchange

The Toronto Stock Exchange
Symbol AXL

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Officers

J.C. Anderson
Chairman of the Board

Brian H. Dau
President & Chief Executive Officer

David M. Spyker
Chief Operating Officer

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

Blaine M. Chicoine
Vice President, Operations

Philip A. Harvey
Vice President, Exploitation

Daniel F. Kell
Vice President, Land

Jamie A. Marshall
Vice President, Exploration

Abbreviations used

AECO – intra-Alberta Nova inventory transfer price
bbl – barrel
bpd – barrels per day
Mbbls – thousand barrels
BOE – barrels of oil equivalent
BOED – barrels of oil equivalent per day
MBOE – thousand barrels of oil equivalent
MMBOE – million barrels of oil equivalent
CBM – Coal Bed Methane
GJ – gigajoule
Mcf – thousand cubic feet
Mcfd – thousand cubic feet per day
MMcf – million cubic feet
MMcfd – million cubic feet per day
Bcf – billion cubic feet
Tcf – trillion cubic feet