

## ANDERSON ENERGY ANNOUNCES 2009 SECOND QUARTER RESULTS

Calgary, Alberta, August 13, 2009 - Anderson Energy Ltd. ("Anderson Energy" or the "Company") (TSX:AXL) is pleased to announce its operating and financial results for the second quarter ended June 30, 2009.

### HIGHLIGHTS:

- The Company achieved average production of 7,789 BOED in the second quarter of 2009, only slightly lower than the comparative period in the prior year in spite of the fact that capital activity levels were cut and some assets were sold late in 2008.
- Funds from operations were \$6.7 million (\$0.06 per share) in the second quarter of 2009, down 76% from the second quarter of 2008 due to a 64% decline in commodity prices and slightly lower production.
- The Company's current drilling inventory, including the recent farm-in lands, is 1,805 gross (994 net) locations with the Edmonton Sands representing 96% of the net locations.
- The average royalty rate as a percentage of revenue was 7% in the second quarter of 2009 compared to 22% in the comparable quarter of 2008. The reduction in royalties is primarily due to receipt of higher than expected gas cost allowance adjustments related to prior periods and the effect of lower natural gas prices on royalties paid under the Alberta New Royalty Framework.
- The Company was successful in reducing operating expenses in the second quarter of 2009 to \$9.58 per BOE, a decrease of 15% from the comparable quarter of 2008 and 11% from the first quarter of 2009. The Company's planned winter drilling program and new plant construction plans are expected to provide further opportunities to significantly reduce operating expenses by the second quarter of 2010.
- The Alberta government continues to make modifications to its recently announced new royalty incentives. These modifications benefit Anderson Energy. The royalty incentive programs include a drilling credit of \$200 per meter drilled for wells drilled from April 1, 2009 through March 31, 2011, as well as a 5% royalty in the first year of production on up to 500 MMcf of gas production from wells tied in between April 1, 2009 and March 31, 2011. With respect to the Company's Edmonton Sands drilling program, the \$200 per drilling meter royalty credit is approximately the same as the Company's drilling cost.
- On May 28, 2009, the Company closed a bought deal financing pursuant to a short form prospectus, issuing 63,200,000 common shares at a price of \$0.95 per common share for net proceeds to the Company of \$56.5 million. The financing was used to pay down debt and provide financial flexibility for the upcoming drilling season.

## FINANCIAL AND OPERATING HIGHLIGHTS

<i>(thousands of dollars, unless otherwise stated)</i>	<i>Three months ended June 30</i>			<i>Six months ended June 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	\$ 17,508	\$ 49,021	(64%)	\$ 41,937	\$ 86,716	(52%)
Funds from operations	\$ 6,692	\$ 27,321	(76%)	\$ 15,484	\$ 44,912	(66%)
Funds from operations per share						
Basic	\$ 0.06	\$ 0.31	(81%)	\$ 0.16	\$ 0.51	(69%)
Diluted	\$ 0.06	\$ 0.31	(81%)	\$ 0.16	\$ 0.51	(69%)
Earnings (loss)	\$ (10,410)	\$ 8,509	(222%)	\$ (20,569)	\$ 10,205	(302%)
Earnings (loss) per share						
Basic	\$ (0.09)	\$ 0.10	(190%)	\$ (0.21)	\$ 0.12	(275%)
Diluted	\$ (0.09)	\$ 0.10	(190%)	\$ (0.21)	\$ 0.12	(275%)
Capital expenditures, including acquisitions net of dispositions	\$ 2,130	\$ 16,772	(87%)	\$ 15,675	\$ 52,131	(70%)
Debt, net of working capital				\$ 69,871	\$ 104,162	(33%)
Shareholders' equity				\$ 347,515	\$ 345,501	1%
Average shares outstanding <i>(thousands)</i>						
Basic	110,914	87,297	27%	99,172	87,296	14%
Diluted	110,914	87,604	27%	99,172	87,603	13%
Ending shares outstanding <i>(thousands)</i>				150,500	87,300	72%
Average daily sales:						
Natural gas <i>(Mcf/d)</i>	40,495	39,881	2%	41,415	39,546	5%
Liquids <i>(bpd)</i>	1,040	1,265	(18%)	1,243	1,305	(5%)
Barrels of oil equivalent <i>(bpd)</i>	7,789	7,912	(2%)	8,145	7,896	3%
Average prices:						
Natural gas <i>(\$/Mcf)</i>	\$ 3.43	\$ 10.26	(67%)	\$ 4.31	\$ 8.92	(52%)
Liquids <i>(\$/bbl)</i>	\$ 49.00	\$ 97.61	(50%)	\$ 43.03	\$ 90.55	(52%)
Barrels of oil equivalent <i>(\$/BOE)</i>	\$ 24.70	\$ 68.08	(64%)	\$ 28.45	\$ 60.35	(53%)
Royalties <i>(\$/BOE)</i>	\$ 1.81	\$ 14.70	(88%)	\$ 3.88	\$ 13.41	(71%)
Operating costs <i>(\$/BOE)</i>	\$ 9.58	\$ 11.32	(15%)	\$ 10.22	\$ 11.72	(13%)
Operating netback <i>(\$/BOE)</i>	\$ 13.31	\$ 42.06	(68%)	\$ 14.35	\$ 35.22	(59%)
General and administrative <i>(\$/BOE)</i>	\$ 2.34	\$ 2.48	(6%)	\$ 2.49	\$ 2.32	7%
Wells drilled <i>(gross)</i>	-	1	(100%)	11	87	(87%)

## 2009 SECOND QUARTER IN REVIEW

The Company was not operationally active in the second quarter as a result of spring breakup and weak natural gas prices. In the second quarter, 3 gross (2.5 net) wells were tied in for production and the Company conducted no drilling operations.

For the quarter ended June 30, 2009, production averaged 7,789 BOED. As expected, production was impacted by plant turnarounds in the second quarter. The Company expects average production in the third quarter of 2009 to be 7,000 to 7,400 BOED. Current behind pipe production capability is approximately 1,000 BOED. In addition, the Company has shut-in approximately 300 BOED of production due to poor natural gas prices. Production is also being negatively impacted by approximately 140 BOED as a result of reductions in ethane sales due to the deep cut facility not operating at Bigoray. Lower NGL recoveries will likely continue in the third quarter with deep cut capabilities expected to be reinstated in the fourth quarter.

Capital expenditures, net of dispositions, were \$2.1 million in the second quarter of 2009 and were comprised mainly of expenditures on Edmonton Sands well tie-ins and capitalized G&A.

The Company's funds from operations were \$6.7 million in the second quarter of 2009 as compared to \$27.3 million in the second quarter of 2008. The Company's average natural gas sales price was \$3.43 per Mcf in the second quarter of 2009 as compared to \$10.26 per Mcf in the second quarter of 2008. The Company's average crude oil and natural gas liquids sales price was \$49.00 per bbl as compared to \$97.61 per bbl. The Company's operating netback was \$13.31 per BOE in the second quarter of 2009 as compared to \$42.06 per BOE in the second 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 second quarter of 2009 was 7% as compared to 22% in the comparable quarter of 2008. The reduction is primarily due to higher GCA recoveries relating to prior periods and the effect of lower natural gas prices on royalties paid under the Alberta New Royalty Framework. Operating expenses in the second quarter of 2009 were \$9.58 per BOE, which were 15% lower than the comparable quarter of 2008 and 11% lower than the first quarter of 2009. The Company has recently implemented various operating expense reduction initiatives on its asset base, including negotiations with service providers and the shut-in of higher cost production. In addition, the Wilson Creek discovery is flowing into the Wilson Creek gas plant which was constructed in 2008 and is the first gas plant constructed to specifications designed specifically for operation in the Edmonton Sands ("fit for purpose plant"). The plant was operating at full capacity in the second quarter. The second quarter operating expenses of the facility were approximately \$2.30 per BOE. The Company is reviewing the potential to construct similar facilities to compress gas produced from wells to be drilled on lands under its recently announced Edmonton Sands farm-in agreement.

## 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. The Company expects to commence drilling in a meaningful way in the fourth quarter of 2009. The first 200 wells will be concentrated on the Farmor's contiguous land blocks.

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.

The Company is currently bidding out work to various service providers for the upcoming winter drilling program. Based on the bidding work done to date, the Company estimates it might save 23% on its drilling and completion costs in the Edmonton Sands program as compared to fourth quarter 2008 costs. Company engineers are identifying locations of new gas plant and well tie-ins for the upcoming winter programs. At present, the Company is considering building two new fit for purpose Edmonton Sands gas plants and connecting most of the remaining wells to be drilled to six existing gas plants. The Company has a working interest in three of those gas plants. The Company's goal is to tie-in all of the successful wells drilled from this winter's 125 well program by spring breakup at an average estimated operating cost of \$5.00/BOE. The Company is presently bidding out the equipping, tie-in, plant installation and construction program associated with the winter drilling program. The bidding process is expected to be completed sometime this fall.

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 June 30, 2009 the Company's 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	595
Horseshoe Canyon CBM (as booked in the AJM reserves report)	120	23
Other	27	19
<b>Total</b>	<b>1,805</b>	<b>994</b>

## 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 approximately 75% of the Farm-In lands are 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. With the Edmonton Sands drilling costs similar to the \$200 per meter drilling credit, the net impact on the Company is that the drilling portion of the Edmonton Sands wells could be at no net cost to the Company for this winter's program. 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. Details of the program will not be confirmed until the program is passed into legislation which is expected to occur sometime this fall.

## SHARE OFFERING

On May 28, 2009, the Company completed a financing under a short form prospectus and 63,200,000 common shares at a price of \$0.95 per common share were issued for gross proceeds to Anderson Energy of approximately \$60 million (\$56.5 million net of commission and expenses).

Proceeds of the share offering 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 commitments under the Farm-In. On May 13, 2009, the Company agreed with its lenders to renew its credit facilities to July 13, 2010 at an available limit of \$100 million.

## PEOPLE

On June 12, 2009, Chris Fong joined the Board of Directors of Anderson. Mr. Fong recently retired from his position as Global Head, Corporate Banking, Energy, with RBC Capital Markets. Mr. Fong brings a unique insight into financing the energy business from both a corporate banking and investment banking perspective and has developed relationships with many of the senior executives in the Canadian energy industry. Mr. Fong is a professional engineer and the Board of Directors and management of the Company are excited about working with Mr. Fong as a member of the Board and believe his extensive experience in the Canadian and international energy business will be a significant asset to the Company.

On July 9, 2009, Dave Spyker was promoted to Chief Operating Officer from Vice President, Business Development. Mr. Spyker will oversee all aspects of the Company's operations in addition to retaining his business development responsibilities. Mr. Spyker's focus over the next year will be on the execution of the Edmonton Sands Farm-In program and on the reduction of costs in the field.

## OUTLOOK

The Company has seen significant and 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 are 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, primarily 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 based on information from the Energy Information Administration. According to Baker Hughes Inc. rig data, in August 2008, the U.S. natural gas rig count peaked at 1,606 rigs, and in October 2008, the U.S. oil and gas horizontal rig count peaked at 650 rigs. Since then, the U.S. natural gas rig count has dropped to 681 rigs, and is at lows not seen since November 2002. The U.S. oil and gas horizontal rig count has declined to 422 rigs. Shale gas wells typically have first year declines of 70 to 80 per cent and second year declines of 30 to 40 per cent. With the collapse in U.S. natural gas rig counts, the reduction in the horizontal rig count and the inherent high first year shale gas declines, the Company expects U.S. natural gas production to decline in the second half of 2009. Although natural gas prices are weaker today than last year, and may get lower prior to heading into winter, the Company expects U.S. natural gas prices to climb late in the year as a consequence of reduced U.S. production. Historically in the natural gas business, the level of supply of natural gas is corrected, upward or downward, by strong or weak natural gas prices. The strength of price response later in the year will likely be impacted by the duration and impact of the U.S. recession.

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 take advantage of that opportunity. The recently completed financing has provided the Company with more financial flexibility to pursue its objectives. The Company is very enthused about its Farm-In and drilling is expected to commence in the fourth quarter of 2009 on these lands.

The Company is not expecting to conduct any other drilling operations until the fourth quarter of 2009. The Company will be bringing on production 7 gross (6.4 net) Edmonton Sands standing wells in the last half of the year.

The Company encourages anyone interested in further details on our Company to visit the Company's website at [www.andersonenergy.ca](http://www.andersonenergy.ca).

Brian H. Dau  
President & Chief Executive Officer  
August 13, 2009

## Management's Discussion and Analysis

FOR THE THREE AND SIX MONTHS ENDED JUNE 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 six months ended June 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 August 12, 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 for the three months ended June 30, 2009 averaged 7,789 BOED, 8% lower than the first quarter of 2009. Significantly lower natural gas prices and the decrease in production volumes offset by lower royalties resulted in funds from operations of \$6.7 million for the three months ended June 30, 2009, compared to \$8.8 million for the first quarter of 2009.

Capital expenditures were \$2.1 million for the three months ended June 30, 2009. During the second quarter of 2009, the Company did not drill any wells. The Company tied in 3 gross (2.5 net) wells for production during the second quarter of 2009.

Debt, net of working capital, was \$69.9 million at June 30, 2009, a reduction of \$61.1 million from March 31, 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 87% of Anderson Energy's total oil and gas sales volumes for the three months ended June 30, 2009, slightly higher than the first quarter of 2009.

Gas sales volumes for the three months ended June 30, 2009 decreased 4% to 40.5 MMcfd from 42.3 MMcfd in the first quarter of 2009. The decrease is a result of third party plant outages, compressor maintenance at Buck Lake, turnarounds at West Pem and natural production decline. Gas sales volumes increased 2% from the second quarter of 2008 as a result of drilling success partially offset by property dispositions in the fourth quarter of 2008. Gas sales for the six months ended June 30, 2009 were 41.4 MMcfd, 5% higher than the six months ended June 30, 2008.

Oil sales for the three months ended June 30, 2009 averaged 410 bpd compared to 443 bpd in the first quarter of 2009 and 436 bpd for the second quarter of 2008. Oil sales for the six months ended June 30, 2009 were 427 bpd, 17% lower than the first half 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 June 30, 2009 averaged 630 bpd compared to 1,005 bpd in the first quarter of 2009 and 829 bpd for the second quarter of 2008. Natural gas liquids sales for the six months ended June 30, 2009 averaged 816 bpd compared to 793 bpd for the first half of 2008. Decreases in 2009 are due to plant turnarounds in May 2009 and reductions in ethane sales due to the deep cut facility not operating at Bigoray. The facility is not expected to be running again until the fourth quarter of 2009.

Royalty and other revenue include 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 June 30, 2009 and 2008.

#### OIL AND NATURAL GAS REVENUE

<i>(thousands of dollars)</i>	<i>Three months ended June 30</i>		<i>Six months ended June 30</i>	
	<i>2009</i>	<i>2008</i>	<i>2009</i>	<i>2008</i>
Natural gas	\$ 12,644	\$ 37,249	\$ 32,282	\$ 65,526
Natural gas economic hedging loss	-	-	-	(1,341)
Oil	2,181	4,580	3,895	9,452
NGL	2,455	6,657	5,783	12,051
Royalty and other	228	535	(23)	1,028
<b>Total</b>	<b>\$ 17,508</b>	<b>\$ 49,021</b>	<b>\$ 41,937</b>	<b>\$ 86,716</b>

## PRODUCTION

	<i>Three months ended June 30</i>		<i>Six months ended June 30</i>	
	<i>2009</i>	<i>2008</i>	<i>2009</i>	<i>2008</i>
Natural gas (Mcf)	40,495	39,881	41,415	39,546
Oil (bpd)	410	436	427	512
NGL (bpd)	630	829	816	793
<b>Total (BOED)</b>	<b>7,789</b>	<b>7,912</b>	<b>8,145</b>	<b>7,896</b>

## PRICES

	<i>Three months ended June 30</i>		<i>Six months ended June 30</i>	
	<i>2009</i>	<i>2008</i>	<i>2009</i>	<i>2008</i>
Natural gas (\$/Mcf)	\$ 3.43	\$ 10.26	\$ 4.31	\$ 8.92
Oil (\$/bbl)	58.42	115.48	50.44	101.50
NGL (\$/bbl)	42.86	88.21	39.15	83.48
<b>Total (\$/BOE)*</b>	<b>\$ 24.70</b>	<b>\$ 68.08</b>	<b>\$ 28.45</b>	<b>\$ 60.35</b>

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

Anderson Energy's average gas sales price was \$3.43 per Mcf for the three months ended June 30, 2009, 33% lower than the first quarter of 2009 price of \$5.15 per Mcf and 67% lower than the second quarter of 2008 price of \$10.26 per Mcf. Anderson Energy's average gas sales price was \$4.31 per Mcf for the six months ended June 30, 2009, 52% lower than the first half of 2008 price of \$8.92 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 six months ended June 30, 2008 was \$9.10 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. 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 25 MMcfd of natural gas sales for various terms ranging from one to seven years.

**Hedging Contracts.** There were no physical or financial hedging contracts outstanding as at June 30, 2009.

**Royalties.** Royalties were 7% of revenue for the three months ended June 30, 2009 compared to 18% for the first quarter of 2009 and 22% for the three months ended June 30, 2008. Royalties were 14% of revenue for the six months ended June 30, 2009 compared to 22% for the same period in 2008. In the second quarter of 2009, the Company received \$1.2 million more in GCA adjustments than had previously been accrued relating to 2008 as a result of changes to the corporate average effective royalty rate. The \$1.3 million economic hedging loss in the first quarter of 2008 also impacted the effective royalty rate in 2008. 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. 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 June 30</i>		<i>Six months ended June 30</i>	
	<i>2009</i>	<i>2008</i>	<i>2009</i>	<i>2008</i>
Royalties (%)	7%	22%	14%	22%
Royalties (\$/BOE)	\$ 1.81	\$ 14.70	\$ 3.88	\$ 13.41

*Operating Expenses.* Operating expenses were \$9.58 per BOE for the three months ended June 30, 2009 compared to \$10.81 per BOE in the first quarter of 2009 and \$11.32 per BOE in the second quarter of 2008. Operating expenses were \$10.22 per BOE for the six months ended June 30, 2009 compared to \$11.72 per BOE in the first half 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 in 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.

#### OPERATING NETBACK

<i>(thousands of dollars)</i>	<i>Three months ended June 30</i>		<i>Six months ended June 30</i>	
	<i>2009</i>	<i>2008</i>	<i>2009</i>	<i>2008</i>
Revenue	\$ 17,508	\$ 49,021	\$ 41,937	\$ 86,716
Royalties	(1,284)	(10,586)	(5,718)	(19,274)
Operating expenses	(6,790)	(8,150)	(15,062)	(16,844)
	\$ 9,434	\$ 30,285	\$ 21,157	\$ 50,598
Sales (MBOE)	708.8	720.0	1,474.3	1,437.0
Per BOE				
Revenue	\$ 24.70	\$ 68.08	\$ 28.45	\$ 60.35
Royalties	(1.81)	(14.70)	(3.88)	(13.41)
Operating expenses	(9.58)	(11.32)	(10.22)	(11.72)
	\$ 13.31	\$ 42.06	\$ 14.35	\$ 35.22

*General and Administrative Expenses.* General and administrative expenses were \$1.7 million or \$2.34 per BOE for the three months ended June 30, 2009 compared to \$2.0 million or \$2.62 per BOE in the first quarter of 2009 and \$1.8 million or \$2.48 per BOE for the three months ended June 30, 2008. General and administrative expenses were \$3.7 million or \$2.49 per BOE for the six months ended June 30, 2009 compared to \$3.3 million or \$2.32 per BOE for the first half of 2008. In the first 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 second quarter.

<i>(thousands of dollars)</i>	<i>Three months ended June 30</i>		<i>Six months ended June 30</i>	
	<i>2009</i>	<i>2008</i>	<i>2009</i>	<i>2008</i>
General and administrative (gross)	\$ 2,820	\$ 3,158	\$ 6,323	\$ 6,078
Overhead recoveries	(319)	(331)	(711)	(867)
Capitalized	(840)	(1,041)	(1,944)	(1,873)
General and administrative (net)	\$ 1,661	\$ 1,786	\$ 3,668	\$ 3,338
General and administrative (\$/BOE)	\$ 2.34	\$ 2.48	\$ 2.49	\$ 2.32
% Capitalized	30%	33%	31%	31%

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

**Stock-Based Compensation.** The Company accounts for stock-based compensation plans using the fair value method of accounting. Stock-based compensation costs were \$0.5 million for the second quarter of 2009 (\$0.2 million net of amounts capitalized) versus \$0.4 million (\$0.2 million net of amounts capitalized) in the second quarter of 2008. Stock-based compensation costs were \$1.0 million for the first half of 2009 (\$0.5 million net of amounts capitalized) versus \$0.8 million (\$0.5 million net of amounts capitalized) in the first half of 2008. The small increase is a result of additional stock options being granted to new and existing staff members.

**Interest Expense.** Interest expense was \$1.1 million for the second quarter of 2009, compared to \$1.0 million in the first quarter of 2009 and \$1.2 million in the second quarter of 2008. For the six months ended June 30, 2009, interest expense was \$2.1 million compared to \$2.4 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. At June 30, 2009, the Company had \$8.1 million in cash and cash equivalents which were used to pay down bank loans subsequent to the quarter end. Bank loans net of cash were \$60 million at June 30, 2009 compared to \$85 million at December 31, 2008 and \$81 million at June 30, 2008.

**Depletion and Depreciation.** Depletion and depreciation was \$28.83 per BOE or \$20.4 million for the second quarter of 2009 compared to \$28.85 per BOE or \$22.1 million in the first quarter of 2009 and \$20.15 per BOE or \$14.5 million in the second quarter of 2008. Depletion and depreciation was \$28.84 per BOE or \$42.5 million for the first half of 2009 compared to \$20.18 per BOE or \$29.0 million in the first half 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 half 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 second quarter of 2009. Accretion expense was \$0.6 million for the second quarter of 2009 compared to \$0.5 million in the

second quarter of 2008 and was included in depletion and depreciation expense. Accretion expense increased due to new wells drilled and associated facilities.

**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 \$306 million in tax pools at June 30, 2009, including approximately \$60 million of Canadian Exploration Expense (CEE) and \$27 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 second quarter of 2009 were \$6.7 million (\$0.06 per share), a 24% decrease from the \$8.8 million (\$0.10 per share) recorded in the first quarter of 2009 and 76% lower than the \$27.3 million (\$0.31 per share) recorded in the second quarter of 2008. Funds from operations for the first half of 2009 were \$15.5 million (\$0.16 per share) compared to \$44.9 million (\$0.51 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 higher production. Cash from operating activities decreased year over year for similar reasons. In addition, lower royalties and operating costs payable at June 30, 2009 impacted the change in non-cash working capital.

<i>(thousands of dollars)</i>	<i>Three months ended June 30</i>		<i>Six months ended June 30</i>	
	<i>2009</i>	<i>2008</i>	<i>2009</i>	<i>2008</i>
Cash from operating activities	\$ 2,472	\$ 27,660	\$ 11,770	\$ 45,076
Changes in non-cash working capital	4,220	(375)	2,776	(300)
Asset retirement expenditures	-	36	938	136
<b>Funds from operations</b>	<b>\$ 6,692</b>	<b>\$ 27,321</b>	<b>\$ 15,484</b>	<b>\$ 44,912</b>

**Earnings (loss).** The Company reported a loss of \$10.4 million in the second quarter of 2009 compared to a loss of \$10.2 million for the first quarter of 2009 and earnings of \$8.5 million for the second quarter of 2008. The Company reported a loss of \$20.6 million in the first half of 2009 compared to earnings of \$10.2 million in the first half of 2008. Earnings in the first half of 2009 were negatively impacted by 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 \$16 million on capital expenditures in the six months ended June 30, 2009. The breakdown of expenditures is shown below:

<i>(thousands of dollars)</i>	<i>Three months ended June 30</i>		<i>Six months ended June 30</i>	
	<i>2009</i>	<i>2008</i>	<i>2009</i>	<i>2008</i>
Land, geological and geophysical costs	\$ 48	173	\$ 137	\$ 649
Acquisitions, net of dispositions	(27)	(875)	(54)	(875)
Drilling, completion and recompletion	761	2,148	6,880	24,531
Facilities and well equipment	548	14,201	6,481	26,018
Capitalized G&A	840	1,001	1,944	1,833
Total finding, development & acquisition expenditures	2,170	16,648	15,388	52,156
Change in compressor and other equipment inventory	(38)	44	269	(130)
Office equipment and furniture	(2)	80	18	105
Total capital expenditures	2,130	16,772	15,675	52,131
Non-cash asset retirement obligations and capitalized stock-based compensation	711	640	1,368	2,170
Total cash and non-cash capital additions	\$ 2,841	17,412	\$ 17,043	\$ 54,301

Drilling statistics are shown below:

	<i>Three months ended June 30</i>				<i>Six months ended June 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	-	-	1	0.2	11	8.3	76	54.0
Oil	-	-	-	-	-	-	4	0.9
Dry	-	-	-	-	-	-	7	6.1
Total	-	-	1	0.2	11	8.3	87	61.0
Success rate (%)	-	-	100%	100%	100%	100%	92%	90%

The Company did not drill any new wells during the second quarter of 2009. The Company tied in 3 gross (2.5 net) wells. Approximately \$1.0 million was spent on inventory in the first half of 2009 that was not deployed due to the cutback in the 2008/2009 capital program and which will be available for use in the 2009/2010 capital program.

## CEILING TEST

No impairment was recognized under the ceiling test at June 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 June 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 August 12, 2009, there were 150.5 million common shares outstanding and 7.3 million stock options outstanding.

	<i>Three months ended June 30</i>		<i>Six months ended June 30</i>	
	<i>2009</i>	<i>2008</i>	<i>2009</i>	<i>2008</i>
High	\$ 1.30	\$ 5.39	\$ 1.48	\$ 5.39
Low	\$ 0.65	\$ 3.38	\$ 0.65	\$ 2.44
Close	\$ 0.83	\$ 5.37	\$ 0.83	\$ 5.37
Volume	43,512,134	29,082,974	49,643,262	53,041,297
Shares outstanding at June 30	150,500,401	87,300,401	150,500,401	87,300,401
Market capitalization at June 30	\$ 124,915,333	\$ 468,803,153	\$ 124,915,333	\$ 468,803,153

## LIQUIDITY AND CAPITAL RESOURCES

At June 30, 2009, the Company had outstanding long term bank loans of \$69 million and a working capital deficiency of \$1 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 minimal in the third quarter of 2009, consisting mainly of surveying, wellsite and pipeline right of way acquisitions, as well as the pre-purchase of some equipment for the winter drilling program. The Company also plans to tie-in seven standing wells. Drilling on the farm-in lands is expected to commence in the fourth quarter.

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 June 30, 2009, the Company has a \$90 million extendible revolving term credit facility and a \$10 million working capital credit facility. As a result of the current economic climate and credit market, the Company will incur increased bank margins and fees. 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. The borrowing base is reviewed semi-annually with the next review scheduled for November 2009, and is based on the bank syndicate's interpretations of the Company's reserves and future commodity prices.

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 \$1.8 million per year in 2009 through 2011, and \$1.7 million in 2012.
- *Firm service transportation commitments* – The Company has entered into firm service transportation agreements for approximately 25 million cubic feet per day of gas sales for various terms expiring between 2009 and 2015. Based on rate schedules announced to date, the payments in each of the next five years and thereafter are estimated to be \$0.6 million in the remainder of 2009, \$1.1 million in 2010, \$0.9 million in 2011, \$0.5 million in 2012, \$0.2 million in 2013 and \$0.4 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 and to complete the commitment, the Company estimates that it could spend between \$10 and \$14 million in 2009 and between \$39 and \$45 million in 2010 on the farm-in. See note 8 to the consolidated interim financial statements for the period ended June 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, scheduled to take place during the last half of 2009, the Company will perform 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 will continue in 2009 and 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 June 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 June 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 June 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

Market events and conditions, including disruptions in the international credit markets and other financial systems and the deterioration of global economic conditions, have caused significant volatility in commodity prices. These conditions are continuing in 2009, contributing to a loss of confidence in global credit and financial markets and creating a climate of greater volatility, less liquidity, widening credit spreads, a lack of price transparency, increased credit losses and tighter credit conditions. These factors have negatively impacted market valuations and are expected to continue to impact the performance of the global economy going forward.

While we may be seeing some signs of potential recovery in equity markets, commodity prices are expected to remain volatile in the near term as a result of uncertainties over the supply and demand for commodities due to the current state of world economies, OPEC actions and the ongoing global credit and liquidity concerns.

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.

Oil and gas exploration and production is capital intensive and involves a number of business risks including 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, the U.S. dollar exchange rate, transportation costs, political stability and

seasonal and weather related changes to demand. 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.

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 and have a material adverse impact on Anderson Energy.

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 review is expected to be completed in the fall of 2009 after consultation with industry.

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.

Canada is a signatory to the United Nations Framework Convention on Climate Change and has adopted the Kyoto Protocol established thereunder requiring binding targets to reduce national emissions of carbon dioxide, methane, nitrous oxide and other greenhouse gases. Details

regarding Canada's implementation of the Kyoto Protocol remain unclear. The Government of Canada has indicated an intention to regulate emissions of industrial greenhouse gas ("GHG") emissions from a broad range of industrial sectors in the *Regulatory Framework for Air Emissions* released April 26, 2007 and updated in a March 10, 2008 document entitled *Turning the Corner: Regulatory Framework for Industrial Greenhouse Gas Emissions* (collectively, the "Federal Plan"). The Federal Plan states the Government of Canada's national GHG emissions reduction target is an absolute 20 percent reduction from 2006 levels by 2020, and a 60 to 70 percent reduction by 2050. The Federal Plan provides some, but not full, detail on planned new GHG and industrial air pollutant limits and compliance mechanisms that the Government of Canada intends to apply to various sectors, including oil and natural gas producers. Details on potential legislation to enact the proposed Federal Plan remain unclear. The Government of Canada has expressed an interest in pursuing a potential harmonization of future Canadian GHG regulation with future regulation in the United States of America, pursuant to a treaty and is participating in United Nations negotiations for an agreement to succeed the Kyoto Protocol which expires in 2012, raising uncertain implications for GHG emission requirements to be applied to Canadian industry, including the oil and gas sector.

In 2007, the Government of Alberta enacted the *Specified Gas Emitters Regulation*, under the *Climate Change and Emissions Management Act (Alberta)*, imposing certain greenhouse gas emissions reduction requirements on large industrial emitters. In January 2008, the Government of Alberta announced a new Climate Change Strategy stating a provincial target of an absolute reduction in greenhouse gas emissions of 14 percent below 2005 levels by 2050. Details on potential legislation to achieve the proposed provincial target remain unclear.

Future federal legislation, including potential international requirements enacted under Canadian law, as well as provincial emissions reduction requirements, may require the reduction of GHG or other industrial air emissions, or emissions intensity, from the Company's operations and facilities. Mandatory emissions reduction requirements may result in increased operating costs and capital expenditures for oil and natural gas producers. The Company is unable to predict the impact of emissions reduction legislation on the Company and it is possible that such legislation may have a material adverse effect on its business, financial condition, results of operations and cash flows.

Anderson believes that it is in material compliance with applicable environmental legislation and is committed to continued compliance. The Company believes that it is reasonably likely that a trend towards stricter standards in environmental legislation will continue and the Company anticipates making increased expenditures of both a capital and an expense nature as a result of increasingly stringent environmental laws.

## **BUSINESS PROSPECTS**

The Company believes it has an excellent future drilling inventory with several years of development drilling locations in the Sylvan Lake Edmonton Sands and Horseshoe Canyon Coal Bed Methane resource plays and the West Pembina Rock Creek play.

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 quarter of 2009 and tied in 32 Edmonton Sands wells. Three wells were tied in during the second quarter. 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 second half of 2009 on the farm-in lands. The recently completed equity financing and the renewal of the Company's credit facilities provide the Company with the financial flexibility to take advantage of the opportunities provided by the farm-in.

The Company expects average production in the third quarter of 2009 to be 7,000 to 7,400 BOED. Risks associated with this guidance include 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. The \$117.6 million acquisition completed in September 2007 had a significant impact on operating results in 2008. Product prices improved significantly between the third quarter of 2007 and the second quarter of 2008, which had a significant impact on funds from operations and earnings in the second quarter of 2008. 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)

	Q2 2009	Q1 2009	Q4 2008	Q3 2008
Oil and gas revenue before royalties	\$ 17,508	\$ 24,429	\$ 30,102	\$ 39,427
Funds from operations	\$ 6,692	\$ 8,792	\$ 13,204	\$ 21,212
Funds from operations per share				
Basic	\$ 0.06	\$ 0.10	\$ 0.15	\$ 0.24
Diluted	\$ 0.06	\$ 0.10	\$ 0.15	\$ 0.24
Earnings (loss) before goodwill impairment	\$ (10,410)	\$ (10,159)	\$ (5,865)	\$ 4,160
Earnings (loss) before goodwill impairment per share				
Basic	\$ (0.09)	\$ (0.12)	\$ (0.07)	\$ 0.05
Diluted	\$ (0.09)	\$ (0.12)	\$ (0.07)	\$ 0.05
Earnings (loss)	\$ (10,410)	\$ (10,159)	\$ (41,229)	\$ 4,160
Earnings (loss) per share				
Basic	\$ (0.09)	\$ (0.12)	\$ (0.47)	\$ 0.05
Diluted	\$ (0.09)	\$ (0.12)	\$ (0.47)	\$ 0.05
Capital expenditures, including acquisitions net of dispositions	\$ 2,130	\$ 13,545	\$ 27,470	\$ 27,068
Cash from operating activities	\$ 2,472	\$ 9,298	\$ 11,261	\$ 26,351
Daily sales				
Natural gas (Mcf)	40,495	42,344	38,090	38,703
Liquids (bpd)	1,040	1,448	1,341	1,221
BOE (bpd)	7,789	8,505	7,689	7,671
Average prices				
Natural gas (\$/Mcf)	\$ 3.43	\$ 5.15	\$ 6.76	\$ 7.86
Liquids (\$/bbl)	\$ 49.00	\$ 38.69	\$ 48.49	\$ 90.19
BOE (\$/BOE)*	\$ 24.70	\$ 31.91	\$ 42.55	\$ 55.87

	Q2 2008	Q1 2008	Q4 2007	Q3 2007
Oil and gas revenue before royalties	\$ 49,021	\$ 37,695	\$ 27,775	\$ 17,261
Funds from operations	\$ 27,321	\$ 17,591	\$ 12,564	\$ 6,255
Funds from operations per share				
Basic	\$ 0.31	\$ 0.20	\$ 0.14	\$ 0.09
Diluted	\$ 0.31	\$ 0.20	\$ 0.14	\$ 0.09
Earnings (loss)	\$ 8,509	\$ 1,696	\$ 4,867	\$ (3,018)
Earnings (loss) per share				
Basic	\$ 0.10	\$ 0.02	\$ 0.06	\$ (0.04)
Diluted	\$ 0.10	\$ 0.02	\$ 0.06	\$ (0.04)
Capital expenditures, including acquisition net of dispositions	\$ 16,772	\$ 35,359	\$ 30,300	\$ 135,966
Cash from operating activities	\$ 27,660	\$ 17,416	\$ 11,110	\$ 5,801
Daily sales				
Natural gas (Mcf)	39,881	39,210	35,672	26,860
Liquids (bpd)	1,265	1,345	1,150	843
BOE (bpd)	7,912	7,879	7,095	5,320
Average prices				
Natural gas (\$/Mcf)	\$ 10.26	\$ 7.55	\$ 6.09	\$ 5.00
Liquids (\$/bbl)	\$ 97.61	\$ 83.91	\$ 72.28	\$ 63.31
BOE (\$/BOE)*	\$ 68.08	\$ 52.57	\$ 42.55	\$ 35.27

\* 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](http://www.sedar.com)) and at Anderson Energy's website ([www.andersonenergy.ca](http://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)

	June 30, 2009	December 31, 2008
<b>ASSETS</b>		
Current assets:		
Cash and cash equivalents	\$ 8,138	\$ 1
Accounts receivable and accruals <i>(note 7)</i>	14,040	28,960
Prepaid expenses and deposits	4,012	2,692
	<u>26,190</u>	<u>31,653</u>
Property, plant and equipment <i>(note 1)</i>	486,571	511,880
	<u>\$ 512,761</u>	<u>\$ 543,533</u>
<b>LIABILITIES AND SHAREHOLDERS' EQUITY</b>		
Current liabilities:		
Accounts payable and accruals	\$ 27,557	\$ 71,619
Bank loans <i>(note 2)</i>	68,504	85,314
Asset retirement obligations <i>(note 3)</i>	31,968	30,820
Future income taxes	37,217	46,168
	<u>165,246</u>	<u>233,921</u>
Shareholders' equity:		
Share capital <i>(note 4)</i>	391,637	334,176
Contributed surplus <i>(note 4)</i>	5,011	4,000
Deficit	<u>(49,133)</u>	<u>(28,564)</u>
	347,515	309,612
Commitments <i>(note 8)</i>		
	<u>\$ 512,761</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 June 30,		Six months ended June 30,	
	2009	2008	2009	2008
<b>REVENUES</b>				
Oil and gas sales	\$ 17,508	\$ 49,021	\$ 41,937	\$ 86,716
Royalties	(1,284)	(10,586)	(5,718)	(19,274)
Interest income	<u>12</u>	<u>13</u>	<u>128</u>	<u>45</u>
	16,236	38,448	36,347	67,487
<b>EXPENSES</b>				
Operating	6,790	8,150	15,062	16,844
General and administrative	1,661	1,786	3,668	3,338
Stock-based compensation	248	227	513	460
Interest and other financing charges	1,093	1,191	2,133	2,393
Depletion, depreciation and accretion	<u>21,019</u>	<u>14,985</u>	<u>43,740</u>	<u>29,912</u>
	<u>30,811</u>	<u>26,339</u>	<u>65,116</u>	<u>52,947</u>
Earnings (loss) before taxes	(14,575)	12,109	(28,769)	14,540
Future income tax expense (reduction)	<u>(4,165)</u>	<u>3,600</u>	<u>(8,200)</u>	<u>4,335</u>
Earnings (loss) and comprehensive income (loss) for the period	(10,410)	8,509	(20,569)	10,205
Deficit, beginning of period	<u>(38,723)</u>	<u>(4)</u>	<u>(28,564)</u>	<u>(1,700)</u>
Retained earnings (deficit), end of period	\$ (49,133)	\$ 8,505	\$ (49,133)	\$ 8,505
Earnings (loss) per share (note 4)				
Basic	\$ (0.09)	\$ 0.10	\$ (0.21)	\$ 0.12
Diluted	\$ (0.09)	\$ 0.10	\$ (0.21)	\$ 0.12

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 June 30,		Six months ended June 30,	
	2009	2008	2009	2008
<b>CASH PROVIDED BY (USED IN)</b>				
<b>OPERATIONS</b>				
Earnings (loss) for the period	\$ (10,410)	\$ 8,509	\$ (20,569)	\$ 10,205
Items not involving cash:				
Depletion, depreciation and accretion	21,019	14,985	43,740	29,912
Future income tax expense (reduction)	(4,165)	3,600	(8,200)	4,335
Stock-based compensation	248	227	513	460
Asset retirement expenditures	-	(36)	(938)	(136)
Changes in non-cash working capital:				
Accounts receivable and accruals	3,495	(2,754)	4,710	(7,579)
Prepaid expenses and deposits	(1,277)	(375)	(1,254)	(523)
Accounts payable and accruals	<u>(6,438)</u>	<u>3,504</u>	<u>(6,232)</u>	<u>8,402</u>
	2,472	27,660	11,770	45,076
<b>FINANCING</b>				
Increase (decrease) in bank loans	(42,316)	(6,741)	(16,810)	13,182
Issue of common shares, net of issue costs	56,538	25	56,538	25
Changes in non-cash working capital:				
Accounts payable and accruals	<u>320</u>	<u>-</u>	<u>320</u>	<u>-</u>
	14,542	(6,716)	40,048	13,207
<b>INVESTMENTS</b>				
Additions to property, plant and equipment	(2,157)	(17,647)	(15,729)	(53,006)
Proceeds on disposition of properties	27	875	54	875
Changes in non-cash working capital:				
Accounts receivable and accruals	6,479	3,845	10,210	7,375
Prepaid expenses and deposits	-	463	(66)	120
Accounts payable and accruals	<u>(13,225)</u>	<u>(8,365)</u>	<u>(38,150)</u>	<u>(13,531)</u>
	<u>(8,876)</u>	<u>(20,829)</u>	<u>(43,681)</u>	<u>(58,167)</u>
Increase in cash	8,138	115	8,137	116
Cash and cash equivalents, beginning of period	<u>-</u>	<u>3</u>	<u>1</u>	<u>2</u>
Cash and cash equivalents, end of period	\$ <u>8,138</u>	\$ <u>118</u>	\$ <u>8,138</u>	\$ <u>118</u>
Cash in bank	938	118	938	118
Cash in short term investments	<u>7,200</u>	<u>-</u>	<u>7,200</u>	<u>-</u>
Cash and cash equivalents	\$ <u>8,138</u>	\$ <u>118</u>	\$ <u>8,138</u>	\$ <u>118</u>

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 SIX MONTHS ENDED JUNE 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>June 30, 2009</i>	<i>December 31, 2008</i>
Cost	\$ 703,635	\$ 686,420
Less accumulated depletion and depreciation	(217,064)	(174,540)
<u>Net book value</u>	<u>\$ 486,571</u>	<u>\$ 511,880</u>

At June 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 \$202.1 million (December 31, 2008 - \$204.7 million) have been included in the depletion and depreciation calculation.

For the six months ended June 30, 2009, \$2.4 million (June 30, 2008 - \$2.2 million) of general and administrative costs including \$0.5 million (June 30, 2008 - \$0.4 million) of stock-based compensation costs were capitalized. The future tax liability of \$0.2 million (June 30, 2008 - \$0.1 million) associated with the capitalized stock-based compensation has also been capitalized. For the three months ended June 30, 2009, \$1.1 million (June 30, 2008 - \$1.2 million) of general and administrative costs including \$0.3 million (June 30, 2008 - \$0.2 million) of stock-based compensation costs were capitalized. Capitalized general and

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

administrative costs consist of salaries and associated office rent of staff involved in capital activities.

No impairment was recognized under the ceiling test at June 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 Q3-Q4	4.54	70.00	0.87
2010	6.32	72.00	0.87
2011	7.16	75.00	0.88
2012	7.56	80.00	0.90
2013	7.93	85.00	0.92
2014	8.47	93.85	0.95
2015	8.75	95.73	0.95
Thereafter 2%			

After 2015, 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 2015 forward.

## 2. BANK LOANS

At June 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 six month period was 4.2% (June 30, 2008 – 5.2%).

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 June 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.

The available lending limits of the Facilities are reviewed semi-annually with the next review set for November 2009, and are based on the bank syndicate's interpretations of the Company's reserves and future commodity prices.

### 3. ASSET RETIREMENT OBLIGATIONS

The Company estimates the total undiscounted cash flows required to settle its asset retirement obligations is approximately \$66.2 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% - 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>June 30, 2009</i>	<i>December 31, 2008</i>
Balance, beginning of period	\$ 30,820	\$ 24,526
Liabilities incurred during period	261	3,951
Liabilities settled in period	(938)	(1,132)
Liabilities settled on disposition	-	(1,234)
Change in estimate	609	2,770
Accretion expense	1,216	1,939
Balance, end of period	<u>\$ 31,968</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 (thousands)</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 <sup>(1)</sup>	63,200,000	60,040
Share issue costs	-	(3,502)
Tax effect of share issue costs	-	923
Balance at June 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.*

*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 six months ended June 30, 2009 and year ended December 31, 2008 are as follows:

#### 4. SHARE CAPITAL AND CONTRIBUTED SURPLUS (Continued)

	<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	45,000		1.00
Expirations	(99,400)		7.93
Forfeitures	(234,000)		3.90
Balance at June 30, 2009	7,306,456	\$	4.32
<b>Exercisable at June 30, 2009</b>	<b>4,919,089</b>	<b>\$</b>	<b>4.75</b>

<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>
\$1.00 to \$1.50	53,100	\$ 1.05	4.5	-	\$ -
\$2.26 to \$3.35	935,700	2.68	4.2	-	-
\$3.36 to \$5.00	5,133,656	4.01	3.0	3,744,089	4.01
\$5.01 to \$7.50	543,000	6.15	2.0	534,000	6.16
\$7.51 to \$9.01	641,000	7.93	1.4	641,000	7.93
<b>Total at June 30, 2009</b>	<b>7,306,456</b>	<b>\$ 4.32</b>	<b>3.0</b>	<b>4,919,089</b>	<b>\$ 4.75</b>

The fair value of the options issued during the six months ended June 30, 2009 was \$0.66 per option (June 30, 2008 - \$1.95 per option). The weighted average assumptions used in arriving at the values were: a risk-free interest rate of 1.70% (June 30, 2008 - 3.2%), expected option life of five years (June 30, 2008 - five years), expected volatility of 83% (June 30, 2008 - 45%) and a dividend yield of 0% (June 30, 2008 - 0%).

*Per share amounts.* During the six months ended June 30, 2009 there were 99,172,224 average shares outstanding (June 30, 2008 - 87,295,687). On a diluted basis, there were 99,172,224 weighted average shares outstanding (June 30, 2008 - 87,602,769) after giving effect to dilutive stock options. During the three months ended June 30, 2009 there were 110,913,588 weighted average shares outstanding (June 30, 2008 - 87,296,972). On a diluted basis, there were 110,913,588 weighted average shares outstanding (June 30, 2008 - 87,603,995) after giving effect to dilutive stock options. At June 30, 2009, there were 7,306,456 options that were anti-dilutive (June 30, 2008 - 3,930,300).

#### 4. SHARE CAPITAL AND CONTRIBUTED SURPLUS *(Continued)*

##### *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	1,011
Balance at June 30, 2009	\$ 5,011

#### 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 \$348 million, long term bank loans of \$69 million and the working capital deficiency of \$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.

	<i>June 30, 2009</i>	<i>December 31, 2008</i>
Bank loans	\$ 68,504	\$ 85,314
Current liabilities	27,557	71,619
Current assets	(26,190)	(31,653)
Total debt	\$ 69,871	\$ 125,280
Cash from operating activities in quarter	\$ 2,472	\$ 11,261
Changes in non-cash working capital	4,220	1,464
Asset retirement expenditures	-	479
Funds from operations in quarter	\$ 6,692	\$ 13,204
Annualized current quarter funds from operations	\$ 26,768	\$ 52,816
Total debt to funds from operations	2.6	2.4

## 5. MANAGEMENT OF CAPITAL STRUCTURE *(Continued)*

At June 30, 2009, the Company's total debt to annualized funds from operations was 2.6. During the fourth quarter of 2008 and the first half of 2009, commodity prices decreased significantly, adversely affecting the Company's cash flow. Natural gas prices at the end of the second quarter of 2009 were lower than the average prices received in the quarter and used in this calculation. 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 \$100.0 million (note 2) to provide funding for its farm-in commitments (note 8) and other minor 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>June 30, 2009</i>	<i>June 30, 2008</i>
Interest paid	\$ 1,818	\$ 1,940
<u>Interest received</u>	<u>(129)</u>	<u>(49)</u>

## 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 June 30, 2009, the maximum credit exposure is the carrying amount of the accounts receivable and accruals of \$14.0 million (December 31, 2008 - \$29.0 million). As at June 30, 2009, the Company's receivables consisted of \$6.6 million (December 31, 2008 - \$17.3 million) from joint venture partners and other trade receivables and \$7.4 million (December 31, 2008 - \$11.7 million) of revenue accruals and other receivables from petroleum and natural gas

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

marketers. Of the \$7.4 million of revenue accruals and receivables from petroleum and natural gas marketers, \$5.7 million was received on or about July 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 June 30, 2009 is \$1.4 million. The Company did not write-off any receivables during the six months ended June 30, 2009.

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

<i>Aging</i>	<i>June 30, 2009</i>	
Not past due	\$	11,847
Past due by less than 120 days		2,011
Past due by more than 120 days		182
<b>Total</b>	<b>\$</b>	<b>14,040</b>

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.

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

<i>Financial Liabilities</i>	<i>&lt; 1 Year</i>		<i>1 -2 Years</i>	
Accounts payable and accruals	\$	27,557	\$	-
Bank loans – principal		-		68,504
<b>Total</b>	<b>\$</b>	<b>27,557</b>	<b>\$</b>	<b>68,504</b>

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 June 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 six months ended June 30, 2009 and there were no commodity price risk contracts outstanding at June 30, 2009 or December 31, 2008.

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

*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 six months ended June 30, 2009, if interest rates had been 1% lower with all other variables held constant, earnings for the period would have been \$0.3 million (June 30, 2008 - \$0.3 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 June 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 the average working interest of the 200 well commitment is approximately 65% 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. To complete the commitment, the Company estimates that it could spend between \$10 and \$14 million in 2009 and between \$39 and \$45 million in 2010 on the farm-in.

The Company has entered into an agreement to lease office space until November 30, 2012. Future minimum lease payments are expected to be \$0.9 million for the remainder of 2009, \$1.8 million in 2010 through 2011 and \$1.7 million in 2012.

**8. COMMITMENTS** *(Continued)*

The Company entered into firm service transportation agreements for approximately 25 million cubic feet per day of gas sales in central Alberta for various terms expiring in one to seven years. 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 Q3-Q4	24	\$ 626
2010	20	\$ 1,081
2011	16	\$ 919
2012	8	\$ 528
2013	2	\$ 231
Thereafter	2	\$ 391

## Corporate Information

Head Office  
700 Selkirk House  
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### Directors

J.C. Anderson <sup>(2)(3)</sup>  
Calgary, Alberta

Brian H. Dau <sup>(3)</sup>  
Calgary, Alberta

Chris L. Fong <sup>(1)(2)</sup>  
Calgary, Alberta

Glenn D. Hockley <sup>(1)(3)</sup>  
Calgary, Alberta

David G. Scobie <sup>(1)(2)</sup>  
Calgary, Alberta

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

## Contact Information

Anderson Energy Ltd.  
Brian H. Dau  
President & Chief Executive Officer  
(403) 206-6000

### 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  
Mcfcd – thousand cubic feet per day  
MMcf – million cubic feet  
MMcfcd – million cubic feet per day  
Bcf – billion cubic feet