



ANGLEENERGYINC



Third Quarter Interim Report for the Three and Nine Months Ended September 30, 2007

HIGHLIGHTS

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2007	2006	2007	2006
<i>(000s, except per share data)</i>	(\$)	(\$)	(\$)	(\$)
Financial				
Oil and gas revenues	12,351	4,388	41,742	9,864
Funds from operations ⁽¹⁾	6,561	1,516	21,991	3,420
Per share – basic	0.20	0.05	0.68	0.12
Per share – diluted	0.19	0.05	0.65	0.12
Net income	1,225	61	6,718	366
Per share – basic	0.04	0.00	0.21	0.01
Per share – diluted	0.04	0.00	0.20	0.01
Capital expenditures	17,919	19,192	40,547	38,694
Net debt	29,013	7,756	29,013	7,756
Shareholders' equity	70,838	52,445	70,838	52,445
Shares outstanding (#)				
At end of period	32,528	30,198	32,528	30,198
Weighted average – basic	32,528	30,198	32,526	27,949
Weighted average – diluted	33,800	30,742	33,798	28,213
Operating				
Production				
Crude oil (bbls/d)	21	18	7	6
Natural gas liquids (bbls/d)	1,206	645	1,330	483
Natural gas (mmcf/d)	10.6	3.3	11.6	2.4
Total oil equivalent (boe/d)	2,989	1,218	3,268	881
Average wellhead prices				
Crude oil (\$/bbl)	67.40	76.35	67.22	76.35
Natural gas liquids (\$/bbl)	55.27	42.28	50.82	43.58
Natural gas (\$/mcf)	6.26	5.72	7.32	6.22
Total oil equivalent (\$/boe)	44.92	39.16	46.79	41.01
Gross (net) wells drilled (#)				
Oil	1.0 (1.0)	--	1.0 (1.0)	--
Gas	5.0 (4.0)	5.0 (4.4)	10.0 (8.6)	13.0 (11.4)
Dry and abandoned	1.0 (1.0)	2.0 (2.0)	3.0 (2.5)	5.0 (3.9)
Total	7.0 (6.0)	7.0 (6.4)	14.0 (12.1)	18.0 (15.3)
Average working interest (%)	86	91	86	85

(1) Funds from operations and funds from operations per share are not recognized measures under Canadian generally accepted accounting principles ("GAAP"). Funds from operations is calculated by taking net income (loss) and adding back non-cash balances such as depletion, depreciation and accretion, stock-based compensation expense, unrealized gain on financial derivative instruments and future income taxes. Management believes that funds flow from operations is a useful supplemental measure to analyze operating performance and provide an indication of the results generated by the Company's principal business activities. The Company's method of calculating these measures may differ from other companies, and accordingly, they may not be comparable to measures used by other companies.

LETTER TO SHAREHOLDERS

Fellow Shareholder:

Angle Energy Inc. is pleased to report the following results for the three and nine months ended September 30, 2007:

- Drilled 7 gross (6.0 net) wells during the quarter with an 86% success rate and at an average working interest of 86%, including a very significant discovery in the Ferrier area.
- Realized average production of 2,989 boe/d for the third quarter of 2007 and 3,268 boe/d for the nine months ended September 30, 2007, representing a 271% increase over the same nine-month period in 2006.
- Generated third quarter cash flow of \$6,561,000 or \$0.19 per diluted share and \$21,991,000 or \$0.65 per diluted share for the nine months ended September 30, 2007.
- Recorded net income of \$1,225,000 or \$0.04 per diluted share for the third quarter and \$6,718,000 or \$0.20 per diluted share for the nine months ended September 30, 2007.
- Increased our credit facility from \$40 million to \$50 million, which will allow us to take advantage of our drilling prospect inventory.

Operations

During the third quarter, we were able to resume drilling operations at Harmattan and Ferrier, and as a result, are pleased to report overall positive drilling results.

Harmattan/Crossfield

At Harmattan, four wells brought on production at the end of the second quarter in the south end of our Ellerslie sand project have performed at rates significantly below initial test and forecast expectations. This disappointing performance, coupled with the lack of new production tie-ins in the third quarter, resulted in lower production overall for the three months ended September 30, 2007 compared to the previous quarter. Our current production base at Harmattan is from 20 Ellerslie/Mannville wells and three Elkton wells, and we operate 97% of this production. We expect to dedicate \$39 million of our fiscal 2007 capital expenditures budget and anticipate drilling 14 total wells this year in this core area. We have recently drilled and tested two Elkton wells at Harmattan at a total gross rate of 3.7 mmcf/d (3.0 mmcf/d net) with two additional wells (one Elkton, one Ellerslie) to complete and test. Angle has four total wells in the Harmattan area to tie-in, which are anticipated to add a stabilized 300 boe/d. Additionally, we have completed a major section of our pipeline infrastructure, taking gas to the Taylor Harmattan plant. This 8.5 kilometre, 8 inch sour line was brought into operation in late October, allowing us to place approximately 250 boe/d on production at current line pressure. The pipeline is in close proximity to several of our 2008 Harmattan area locations and the line will serve to reduce our tie-in time lines for these new drills.

Ferrier

Angle has had excellent success in this expanding second core area of operations. We have drilled 7 gross (5.7 net) wells since late 2006 and have a 71% completion success rate. During the third quarter at Ferrier, the Company drilled 3 gross (2.0 net) wells targeting the Ellerslie formation, all of which were successful. One of the wells has been flow tested at a significant rate (estimated AOF of 12.0 mmcf/d) and we expect to produce the well at approximately 4.5 mmcf/d (net). The other two wells are currently being flow tested. In addition, we increased our average working interest in these wells from 47% to 63%. We anticipate initial production to commence in the final two months of this year. Current production capacity (tested volumes) in the Ferrier area is 700 boe/d with a further increase expected by way of added compression in the first quarter of 2008. We anticipate drilling up to 3 gross (2.0 net) additional wells in this area during the fourth quarter of 2007.

As of the current date, Angle has tested an additional net 1,000 boe/d from nine wells in the Harmattan and Ferrier areas. These wells are expected to be tied in over the fourth quarter of 2007 and the first quarter of 2008 with forecasted average production for these periods of 3,270 boe/d and 4,120 boe/d, respectively.

New Royalty Framework

On October 25, 2007, the Government of Alberta released the New Royalty Framework ("NRF"). The NRF is the government's response to a report issued September 18, 2007 by the Alberta Royalty Review Panel, which was commissioned by the provincial government to perform a review of the province's royalty system. The NRF addresses royalty changes on oil, natural gas and NGLs, which primarily affects Angle in relation to natural gas and NGLs. Our Company's production is solely within the Province of Alberta. On January 1, 2009, Crown royalty rates for high volume natural gas wells (greater than 580 mcf/d) will be increased materially, but the final determination of royalty payable is sensitive to both natural gas prices and well production rates. Wells drilled to measured depths greater than 2,000 metres will qualify for a reduction in royalty payable. The majority of Angle's acreage has production targets that range in depth from 2,200 to over 2,700 metres. As a consequence, our royalty payable will be reduced at production rates less than 1.0 mmcf/d. The amount of the royalty reduction will be dependent upon the measured drilled depth of the well, the rate of production and the price of natural gas.

We have reviewed the changes proposed by the government to its royalty program to take effect on January 1, 2009 and herein provide our comments. Of our total current royalties payable, 38% are Crown royalties and 62% are freehold and gross overriding royalties. Our royalties attributable to freehold and gross overriding interests will not be affected by the government's NRF program as there are no proposed changes to the government's calculation of mineral tax pertaining to freehold leases. Our leases subject to Crown royalties have natural gas wells with both lower and higher rates of production and have measured depths on average between 2,300 to 2,700 metres. The higher rate wells will be subject to an increased Crown royalty rate, while the lower rate wells will pay decreased royalties.

Based on the information we have to date regarding the impact of the NRF on estimated operating income, we have determined that as a result of the changes proposed in the NRF, our estimated operating income in 2009 (as per the GLJ October 1, 2007 price forecast) will be negatively impaired by less than 1%. Likewise, we see no material impact to our net asset value under this same evaluation. We expect that our mix of Crown to freehold and gross overriding royalties to change to approximately 44% and 56%, respectively, when the NRF is scheduled to take effect in 2009. The impact to operating income and reserves values described above is an evaluation of Angle's internal reserves effective October 1, 2007. We will continue to monitor the NRF as it transitions from the current proposed state into legislation and will provide additional information as it relates to Angle, if material.

Guidance Revision

In our second quarter report, we indicated that we would be undertaking a re-forecast of our 2007 operations and would report any material changes and resulting financial impact. That process was concluded and we issued a letter to our shareholders dated October 2, 2007. We have continued to monitor our operations and have further revised our guidance for the balance of 2007 as shown in the table below. Our revised forecast (compared to our October 2, 2007 guidance) shows average 2007 production declined 3%, cash flow increased 4% and capital expenditures decreased 7%, thereby reducing our expected ending 2007 debt by 11%. The decline in average production is directly attributable to longer project timelines (regulatory in nature) in our pipeline operations, resulting in greater than anticipated tie-in delays.

During the second quarter of 2007, we experienced extensive wet field conditions, and consequently, were unable to complete drilling or pipelining operations. In addition, we have had disappointing production performance from four wells in Harmattan that were tied in at the end of the second quarter. This poor performance equates to approximately one-half of the forecast change in our original second quarter average production guidance for 2007. We have discontinued drilling operations in that particular Ellerslie sand. Although we may be able to rectify this performance issue, we are not forecasting any recovery in production volumes at this time. The overall effect has been a delay in production build and related cash flow for the remainder of 2007. We have also adjusted our pricing assumptions in line with declining natural gas pricing in the forward market. The following table outlines the changes for the fiscal 2007 production period as a result of these factors:

Fiscal 2007	Revised	Forecast	Change	% Change
	Forecast	Forecast		
	October 31, 2007	June 30, 2007		
Average production (boe/d)	3,267	4,140	(873)	(21)
Pricing (\$/boe)	45.74	46.11	(1.67)	(1)
Revenue (\$000s)	54,500	69,700	(15,200)	(22)
Cash flow (\$000s)	28,300	37,000	(8,700)	(24)
Capital expenditures (\$000s)	55,000	57,000	2,000	4
Ending total debt (\$000s)	37,500	30,100	7,400	25
Ending total debt to forward cash flow	1.2	0.7	0.5	71

Outlook

In summary, we added significant value for the Company during the third quarter of 2007 by way of our activity in the Ferrier area. We have drilled a high impact Ellerslie delineation well, yielding several follow-up locations on Angle controlled lands and have expanded our average working interest in the area. Our successful exploration at Ferrier will translate into production gains going forward.

We continue to apply our business plan of internally generating drilling prospects and maintaining control through high working interests and operatorship. Although we primarily target gas bearing zones, our mix of production volume is approximately 59% natural gas and 41% NGLs. Angle continues to record excellent drilling results, including 45 gross (38.8 net) wells drilled since our Company began operations in late 2005 with an 80% net completion success rate. We have also posted an excellent finding and development cost average of \$16.08/boe proved and \$11.35/boe proved plus probable (including future capital expenditures). We have a low cost operating structure of less than \$5.00/boe and we enjoy a favourable recycle ratio of 1.6 proved and 2.3 proved plus probable.

Angle currently has over a year's inventory of drill ready locations on Company controlled lands with a strategic mix of lower risk sand targets and higher impact Elkton and Ellerslie target zones. Our Company is currently producing 3,280 boe/d with additional net tested volumes of 1,000 boe/d from nine wells awaiting tie-in. In early October, we received approval from our bankers to expand our credit facility to \$45 million with further expansion to \$50 million conditional upon the Company attaining a production rate of 3,800 boe/d, which we expect to reach in December 2007.

Our primary objective is to maintain and increase value for all Angle stakeholders. Over the summer, we aggressively evaluated opportunities to provide liquidity for our shareholders; however, thus far during 2007, market conditions have not been favourable for either corporate transactions or the outright sale of the Company. With our low cost operations and drilling inventory, we believe we can provide better value for our shareholders by continuing to grow internally at this time. We will, however, continue to evaluate liquidity opportunities as well as selective acquisition prospects.

We are pleased with the achievements of our professional staff, the guidance from our Board and the ongoing support of our shareholders. We look forward to reporting the results of our efforts throughout the remainder of the year and into 2008.

On behalf of the Board of Directors,

[signed]

Gregg Fischbuch
President & Chief Executive Officer

October 31, 2007

MANAGEMENT'S DISCUSSION AND ANALYSIS

The following Management's Discussion and Analysis ("MD&A") reports on the financial condition and the results of operations of Angle Energy Inc. ("Angle" or the "Company") for the three and nine months ended September 30, 2007 and 2006 and should be read in conjunction with the accompanying September 30, 2007 unaudited interim financial statements and the audited financial statements for the year ended December 31, 2006. All financial measures are expressed in Canadian dollars unless otherwise indicated. This commentary is based on the information available as at, and is dated October 31, 2007.

Production information is commonly reported in units of barrel of oil equivalent or boe. For purposes of computing such units, natural gas is converted to equivalent barrels of oil using a conversion factor of six thousand cubic feet to one barrel of oil. This conversion ratio of 6:1 is based on an energy equivalent wellhead value for the individual products. Such disclosure of boes may be misleading, particularly if used in isolation. Readers should be aware that historical results are not necessarily indicative of future performance.

This MD&A contains the term funds from operations, which should not be considered an alternative to or more meaningful than cash flow from operating activities as determined in accordance with Canadian generally accepted accounting principles ("GAAP") as an indicator of the Company's performance. Therefore, references to funds from operations or funds from operations per share (basic and diluted) may not be comparable with the calculation of similar measures for other entities. Management uses funds from operations to analyze operating performance and leverage, and considers funds from operations to be a key measure as it demonstrates the Company's ability to generate the cash necessary to fund future capital investments and to repay debt. The reconciliation between net income (loss), funds from operations and cash flow from operations can be found in the statements of cash flows in the interim financial statements. Funds from operations per share are calculated using the basic and diluted weighted average number of shares for the period. The Company uses the terms operating and corporate netbacks (defined as oil and gas revenues less royalties and operating costs) to analyze operating performance. Operating and corporate netbacks that may be used in this MD&A do not have a standardized meaning under GAAP, and therefore, it may not be comparable with the calculation of similar measures of other entities.

Forward-Looking Statements

Certain information regarding Angle set forth in this interim report, including management's assessment of Angle's future plans and operations, contains forward-looking statements that involve substantial known and unknown risks and uncertainties. These risks and uncertainties, many of which are beyond Angle's control, include the impact of general economic conditions and specific industry conditions, volatility of commodity prices, currency fluctuations, imprecision of reserves estimates, environmental risks, competition from other producers, the lack of available qualified personnel or management, stock market volatility and ability to access sufficient capital from internal and external sources. Angle's actual results, performance or achievement could differ materially from those expressed in, or implied by, these forward-looking statements, and accordingly, no assurance can be given that any events anticipated by the forward-looking statements will transpire or occur, or if any of them do, what benefits Angle can derive therefrom.

Basis of Presentation

Angle is a privately held company that was incorporated under the laws of Alberta on January 23, 2004 and commenced active oil and gas operations in 2005. This MD&A focuses on the Company's operations for the three and nine months ended September 30, 2007 as compared to the same periods in 2006.

Operating Results

Drilling Activity

	Exploration		Development		Total	
	Gross	Net	Gross	Net	Gross	Net
January 1 to September 30, 2007						
Crude oil & NGLs	--	--	1.0	1.0	1.0	1.0
Natural gas	2.0	2.0	8.0	6.6	10.0	8.6
Dry and abandoned	3.0	2.5	--	--	3.0	2.5
Total wells	5.0	4.5	9.0	7.6	14.0	12.1
Success rate (%)		44		100	86	79
Average working interest (%)		90		84		86

Capital Expenditures

Capital expenditures, summarized in the following table, resulted from our ongoing operations and included expenditures on land, seismic, drilling and facility costs incurred:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2007	2006	2007	2006
(000s)	(\$)	(\$)	(\$)	(\$)
Drilling and completions	13,949	13,562	27,171	28,844
Equipment and facilities	3,814	2,371	10,029	4,837
Geological and geophysical	32	873	262	1,122
Land and lease retention	58	2,252	2,866	3,563
Head office	2	21	25	26
Capitalized G&A and other	64	113	194	292
Total	17,919	19,192	40,547	38,684

For the third quarter of 2007, drilling and completions expenditures totaled \$13,949,000 (compared to \$13,562,000 in same period of 2006) that involved the drilling of 7 gross (6.0 net) wells of which 6 gross (5.0 net) wells were successful and 1 gross (1.0 net) well was dry. In the comparative three-month period of 2006, the Company drilled 7 gross (6.4 net) wells of which 5 gross (4.4 net) wells were successful and 2 gross (2.0 net) wells were dry.

Drilling and completions expenditures totaled \$27,171,000 for the nine months ended September 30, 2007 (compared to \$28,844,000 in same period of 2006), which involved the participation in 14 gross (12.1 net) wells. Of the 14 wells, 11 gross (9.6 net) wells were cased, while the remaining 3 gross (2.5 net) wells were abandoned. In the comparative period of 2006, the Company drilled 18 gross (15.3 net) wells of which 13 gross (11.4 net) wells were successful and 5 gross (3.9 net) wells were dry.

During the third quarter of 2007, the Company's expenditures on facilities totaled \$3,814,000 (2006 – \$2,371,000) primarily for wellsite facilities and related gathering pipelines. For the nine months ended September 30, 2007, we expended \$10,029,000 (2006 – \$4,837,000) primarily on the installation of 41 kilometres of gas gathering pipelines in our Harmattan operating area and 5 kilometres at Ferrier along with related wellsite facilities.

Land purchases and retention costs incurred in the third quarter of 2007 totaled \$58,000 compared to \$2,252,000 in 2006. For the nine months ended September 30, 2007, we expended \$2,866,000 on land purchases and retention costs compared to \$3,563,000 in 2006. During the first nine months of 2007, we were more active in Crown land purchases and, to a lesser degree, freehold leasing.

For the 2007 fiscal year, we now expect to incur total capital expenditures of approximately \$55,000,000 and anticipate drilling 19 to 21 gross wells.

Financial and Operating Results of Oil and Gas Activities

Production, Price and Revenue

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2007	2006	2007	2006
Light crude oil sales (bbls/d)	21	18	7	6
NGLs sales (bbls/d)	1,206	645	1,330	483
Natural gas sales (mmcf/d)	10.6	3.3	11.6	2.4
Total sales (boe/d)	2,989	1,218	3,268	881
Total sales (boe)	274,978	112,081	892,039	240,552
Light crude oil sales price (\$/bbl)	67.40	76.35	67.22	76.35
NGLs sales price (\$/bbl)	55.27	42.28	50.82	43.58
Natural gas sales price (\$/mcf)	6.26	5.72	7.32	6.22
Total sales price (\$/boe)	44.92	39.16	46.79	41.01
Total revenue (\$000s)	12,351	4,388	41,742	9,864

For the third quarter of 2007, revenue was \$12,351,000 on average sales volumes of 2,989 boe/d, which was comprised of approximately 49% natural gas and 51% NGLs on a revenue basis (compared to \$4,388,000 and 1,218 boe/d for the same period in 2006). In the second quarter of 2007, our average sales volume was 3,326 boe/d. The 10% decrease in average production is directly attributable to longer project timelines (regulatory in nature) in our pipeline operations, resulting in greater than anticipated tie-in delays.

For the nine-month period ended September 30, 2007, we recorded \$41,742,000 in revenue on average sales volumes of 3,268 boe/d (versus \$9,864,000 and 881 boe/d for the same period in 2006), which was comprised of approximately 56% natural gas and 44% NGLs on a revenue basis.

Our drilling operations target natural gas, which are rich in associated NGLs. Our production has increased dramatically over 2006 levels due to our successful drilling program, especially in the latter part of 2006 and the first quarter of 2007.

Given the slow down in drilling during the second quarter due to field conditions, we now expect our average production for 2007 to be in the 3,200 to 3,300 boe/d range. This is slightly lower than our guidance provided in our Letter to Shareholders dated October 2, 2007 and is directly related to regulatory challenges in our pipeline operations.

Our production is sold within Canada and we are sensitive to world crude oil and North American natural gas price variations in addition to the Canada/U.S. currency exchange rate changes. All of the Company's production is sold through two purchasers. In the first quarter of 2007, we entered into a fixed price contract to sell 2,700 GJs/d between March 1 and October 31, 2007 for \$7.72/GJ and have recorded \$1,018,000 in realized price gains to September 30, 2007. In October 2007, we entered into new forward sales contracts that are further described in note 12 to these interim financial statements.

Royalties

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2007	2006	2007	2006
(000s)	(\$)	(\$)	(\$)	(\$)
Revenue	12,351	4,388	41,742	9,864
Royalties				
Crown	1,461	17	4,646	103
Other	2,441	1,747	8,818	3,769
Total royalties	3,902	1,764	13,464	3,872
% of Revenue				
Crown	12	1	11	1
Other	20	39	21	38
Total	32	40	32	39

For the third quarter of 2007, we recorded total royalties of \$3,902,000 or 32% of revenue versus \$1,764,000 or 40% of revenue for the same period in 2006. Our royalty rate was lower in 2007 due to a higher proportion of production from Crown leases, which carry a lower royalty rate compared to our freehold and gross overriding royalties.

During the first nine months of 2007, total royalties were \$13,464,000 or 32% of revenue versus \$3,872,000 or 39% of revenue a year ago. Included in the 2007 royalties is an adjustment resulting from an increase in allowable deductions in the calculation of other royalties. The royalty expense was \$15.09/boe (6:1) for the first nine months of 2007 compared to \$16.10/boe in the same period of 2006. The Alberta Royalty Tax Credit program has been discontinued effective January 1, 2007, which has the effect of increasing the royalties on Crown leases.

The majority of our royalties in 2007 and 2006 resulted from production on farm-in lands in the Harmattan area, which are burdened with both a freehold and a gross overriding royalty. Although this royalty rate is higher than a comparable Crown royalty, the farm-in provided access to the drilling opportunities in this area, and consequently, we did not expend capital funds to acquire the mineral rights. We expect our royalty rate will average approximately 33% for the balance of 2007 as we bring on additional production from Crown lands.

On October 25, 2007, The Government of Alberta released the New Royalty Framework ("NRF"). The NRF is the government's response to a report issued September 18, 2007 by the Alberta Royalty Review Panel, which was commissioned by the provincial government to perform a review of the province's royalty system. The NRF addresses royalty changes on oil, natural gas and NGLs, which primarily affects Angle in relation to natural gas and NGLs. Our Company's production is solely within the Province of Alberta. On January 1, 2009, Crown royalty rates for high volume natural gas wells (greater than 580 mcf/d) will be increased materially, but the final determination of royalty payable is sensitive to both natural gas prices and well production rates. Wells drilled to measured depths greater than 2,000 metres will qualify for a reduction in royalty payable. The majority of Angle's acreage has production targets that range in depth from 2,200 to over 2,700 metres. As a consequence, our royalty payable will be reduced at production rates less than 1.0 mmcf/d. The amount of the royalty reduction will be dependent upon the measured drilled depth of the well, the rate of production and the price of natural gas.

We have reviewed the changes proposed by the government to its royalty program to take effect on January 1, 2009 and herein provide our comments. Of our total current royalties payable, 38% are Crown royalties and 62% are freehold and gross overriding royalties. Our royalties attributable to freehold and gross overriding interests will not be affected by the government's NRF program as there are no proposed changes to the government's calculation of mineral tax pertaining to freehold leases. Our leases subject to Crown royalties have natural gas wells with both lower and higher rates of production and have measured depths on average between 2,300 to 2,700 metres. The higher rate wells will be subject to an increased Crown royalty rate, while the lower rate wells will pay decreased royalties.

Based on the information we have to date regarding the impact of the NRF on estimated operating income, we have determined that as a result of the changes proposed in the NRF, our estimated operating income in 2009 (as per the GLJ October 1, 2007 price forecast) will be negatively impaired by less than 1%. Likewise, we see no material impact to our net asset value under this same evaluation. We expect that our mix of Crown to freehold and gross overriding royalties to change to approximately 44% and 56%, respectively, when the NRF is scheduled to take effect in 2009. The impact to operating income and reserves values described above is an evaluation of Angle's internal reserves effective October 1, 2007. We will continue to monitor the NRF as it transitions from the current proposed state into legislation and will provide additional information as it relates to Angle, if material.

Operating Expenses

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2007	2006	2007	2006
(000s)	(\$)	(\$)	(\$)	(\$)
Operating expense	1,166	765	4,119	1,531
Transportation expense	84	15	243	42
Total operating expense	1,250	780	4,362	1,573
Operating expense (\$/boe)	4.55	6.97	4.89	6.54

Total operating expenses were \$1,250,000 or \$4.55/boe (\$4.24/boe excluding transportation expense) for the three months ended September 30, 2007 versus \$780,000 or \$6.97/boe a year ago.

For the nine-month period ended September 30, 2007, we incurred \$4,362,000 or \$4.89/boe in total operating expenses versus \$1,573,000 or \$6.54/boe in the 2006 period. We recorded lower operating costs per boe in both the three and nine-month periods of 2007 compared to 2006 due to increased volumes absorbing fixed operating costs and operating efficiencies on our variable operating expenses. We expect our per unit operating expense to remain in the current range for the balance of 2007.

General and Administrative ("G&A") Expenses and Stock-Based Compensation

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2007	2006	2007	2006
(000s)	(\$)	(\$)	(\$)	(\$)
G&A expenses	641	701	2,074	1,912
G&A capitalized (direct)	(64)	(113)	(194)	(292)
G&A recoveries via operations	(155)	(172)	(426)	(333)
G&A expenses (net)	422	416	1,454	1,287

G&A net expenses totaled \$422,000 for the three months ended September 30, 2007 versus \$416,000 a year ago. During the third quarter of 2007, we capitalized \$64,000 (\$113,000 – 2006) in direct costs relating to our exploration and development efforts and \$155,000 (\$172,000 – 2006) relating to operator recoveries on capital expenditures.

We recorded non-cash stock-based compensation expense of \$223,000 and capitalized \$34,000 for total stock-based compensation of \$257,000 during the third quarter of 2007 compared to stock-based compensation expense of \$203,000 and capitalized \$28,000 for total stock-based compensation of \$231,000 for the same period in 2006.

For the first nine months of 2007, G&A expenses totaled \$1,454,000 compared to \$1,287,000 for the same period in 2006. During this period, we capitalized \$194,000 in direct costs relating to our exploration and development efforts and \$426,000 relating to operator recoveries on capital expenditures. Our G&A expenses increased during 2007 due to staff restructuring costs, yearly fees for computer licenses and finance fees as a result of our new credit facility established during that period.

For the first nine months of 2007, we recorded non-cash stock-based compensation expense of \$928,000 and capitalized \$101,000 for total stock-based compensation of \$1,029,000 compared to stock-based compensation expense of \$457,000 and capitalized \$84,000 for total stock-based compensation of \$541,000 for the same period in 2006. Our non-cash stock-based compensation expense increased as a result of a modification to existing options due to staff restructuring in 2007.

We currently have 11 full time professionals 3 part time consultants, and expect our G&A expenses for fiscal 2007 to be approximately \$2,800,000 before capitalization.

Netbacks (per unit)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2007	2006	2007	2006
	(\$/boe)	(\$/boe)	(\$/boe)	(\$/boe)
Sales prices	44.92	39.16	46.79	41.01
Royalties	(14.19)	(15.74)	(15.09)	(16.10)
Operating	(4.55)	(6.97)	(4.89)	(6.54)
Operating netback	26.18	16.45	26.81	18.37
G&A and other (excludes non-cash items)	(1.53)	(3.72)	(1.63)	(5.35)
Interest expense	(0.79)	--	(0.53)	--
Interest income	--	0.79	--	1.20
Funds flow netback	23.86	13.52	24.65	14.22
Depletion, depreciation and accretion	(14.87)	(10.37)	(12.89)	(11.75)
Stock-based compensation	(0.81)	(1.81)	(1.04)	(1.90)
Unrealized gain on financial derivative instruments	(1.53)	--	0.26	--
(Future tax) recovery	(2.20)	(0.81)	(3.45)	0.95
Net income netback	4.45	0.53	7.53	1.52

Although we have a higher royalty per unit, it is offset by higher sales prices for our natural gas due to the heat content of the gas stream and by lower operating expenses. This has resulted in an operating netback of \$26.18/boe for the three-month period and \$26.81/boe for the nine-month period ended September 30, 2007.

Funds from Operations

For the three months ended September 30, 2007, we recorded funds from operations of \$6,561,000 or \$0.20 per basic and \$0.19 per diluted share compared to \$1,516,000 or \$0.05 per basic and diluted share a year ago.

For the nine months ended September 30, 2007, funds from operations totaled \$21,991,000 or \$0.68 per basic and \$0.65 per diluted share versus \$3,420,000 or \$0.12 per basic and diluted share for the same period in 2006.

Depletion, Depreciation and Accretion ("DD&A")

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2007	2006	2007	2006
DD&A provision (\$000s)	4,089	1,161	11,497	2,826
DD&A provision (\$/boe)	14.87	10.37	12.89	11.75

The DD&A provision for the third quarter of 2007 was \$4,089,000 (\$14.87/boe) compared to \$1,161,000 (\$10.37/boe) recorded in the same quarter of 2006. Our provision increased by \$2,928,000 between these periods with approximately 59% of the change due to the increase in production volumes and the balance as a result of the increase in the unit rate. The unit rate increased during the period due to a downward revision in our internally estimated proved reserves.

For the nine-month period ended September 30, 2007, DD&A provision totaled \$11,497,000, reflecting a depletion provision of \$11,424,000, depreciation of \$16,000 and an accretion provision of \$57,000. In the corresponding period of 2006, we recorded depletion of \$2,755,000, depreciation of \$22,000 and an accretion provision of \$49,000.

Income Taxes

Future tax expense totaled \$603,000 for the three-month period ended September 30, 2007 compared to \$91,000 for the same period in 2006. Future tax expense totaled \$3,078,000 for the nine-month period ended September 30, 2007 compared to a recovery of \$229,000 a year ago. This expense reflects the Company's future tax rate applied to the net earnings adjusted for temporary timing differences.

Net Income

For the three months ended September 30, 2007, we recorded net income of \$1,225,000 or \$0.04 per basic and diluted share compared to net income of \$61,000 or \$0.00 per basic and diluted share in the same period of 2006.

For the nine months ended September 30, 2007, net income totaled \$6,718,000 or \$0.21 per basic and \$0.20 per diluted share compared to net income of \$366,000 or \$0.01 per basic and diluted share a year ago.

Liquidity and Capital Resources

The following table summarizes the change in working capital during the nine-month period ended September 30, 2007 and year ended December 31, 2006:

	Nine Months Ended September 30, 2007	Year Ended December 31, 2006
<i>(000s)</i>	<i>(\$)</i>	<i>(\$)</i>
Working capital (deficiency), beginning of period	(10,772)	15,452
Funds from operations	21,991	7,985
Issue of capital stock for cash (net of share issue expense)	85	23,612
Financial derivative instruments	230	--
Capital expenditures	(40,547)	(57,821)
Working capital (deficiency), end of period	(29,013)	(10,772)

Since inception on January 23, 2004 to September 30, 2007, we have raised funds through treasury equity issues in the amount of \$65,947,000 (net of share issue expenses) at share prices ranging from \$0.60 to \$6.00 per common share.

We exited the third quarter of 2007 with a working capital deficiency, excluding the current portion of ARO, of \$29,013,000 compared to available credit lines of \$40,000,000.

We expect our sales volumes and related cash flow to continue to increase in 2007 based on our forecasted production levels and prices. In order to protect a portion of our revenue stream, in February 2007 we entered into a fixed price contract to sell 2,700 GJs/d of natural gas between March 1 and October 31, 2007 at a price of \$7.72/GJ to our current natural gas purchaser and have entered into another contract arrangement commencing November 1, 2007 and is further described in note 12 to these interim financial statements.

In 2007, we anticipate incurring approximately \$55 million in capital expenditures and expect to fund this by cash flow of \$28 million and end the year with working capital deficiency and bank debt of approximately \$37 million compared to a credit facility of \$45 million, or \$50 million conditional upon the Company attaining a production rate of 3,800 boe/d.

As at October 1, 2007, we had 32,527,941 common shares and 2,870,000 stock options outstanding.

Selected Quarterly Information

Three Months Ended	Dec.31, 2005	Mar.31, 2006	Jun.30, 2006	Sep.30, 2006	Dec.31, 2006	Mar.31, 2007	Jun.30, 2007	Sep.30, 2007
<i>(000s, except per share data)</i>	(\$)	(\$)	(\$)	(\$)	(\$)	(\$)	(\$)	(\$)
Revenues	374	2,858	2,618	4,388	9,757	14,982	14,409	12,351
Funds from operations	(148)	1,122	782	1,516	4,565	8,130	7,300	6,561
Per share – basic	(0.01)	0.04	0.03	0.05	0.15	0.25	0.22	0.20
Net income (loss)	(454)	87	218	61	1,177	2,772	2,721	1,225
Per share – basic	(0.02)	0.00	0.01	0.00	0.04	0.09	0.08	0.04
Capital expenditures	14,929	11,455	8,037	19,192	19,137	17,975	4,653	17,919
Positive working capital (net debt)	15,452	6,619	10,010	(7,756)	(10,772)	(20,481)	(17,236)	(29,013)
Shareholders' equity	40,892	40,775	52,180	52,445	65,344	66,107	69,356	70,838

Critical Estimates

Management is required to make judgements and use estimates in the application of generally accepted accounting principles that have significant impact on the financial results of the Company. The following discussion outlines the accounting policies and practices that are critical to determining our financial results.

Full Cost Accounting

We follow the Canadian Institute of Chartered Accountants' ("CICA") guideline on full cost accounting in the oil and gas industry to account for oil and gas properties. Under this method, all costs associated with the acquisition of, exploration for and development of crude oil and natural gas reserves are capitalized and costs associated with production are expensed. The capitalized costs are depreciated, depleted and amortized using the unit-of-production method based on estimated proved reserves. Reserve estimates can have a significant impact on earnings, as they are a key component in the calculation of DD&A. A downward revision in a reserve estimate could result in a higher DD&A charge to earnings. In addition, if capitalized costs are determined to be in excess of the calculated ceiling, which is based largely on reserves estimates, the excess must be written off as an expense charged against earnings. In the event of a property disposition, proceeds are normally deducted from the full cost pool without recognition of a gain or loss unless there is a change in the DD&A rate of 20% or greater.

Asset Retirement Obligations

We record a liability for the fair value of our legal obligations associated with the retirement of long-lived assets in the period in which it is incurred, normally when the asset is purchased or developed. On recognition of the liability, there is a corresponding increase in the carrying value of the related asset and the asset retirement obligation. The total amount of the asset retirement obligation is an estimate based on our net ownership in all wells and facilities, the estimated cost to abandon and reclaim the wells and facilities, the estimated timing of those cash flows, changes in environmental regulations and the discount rate used to calculate the present value of those cash flows are estimates subject to measurement uncertainty. Any change in these estimates would impact the asset retirement liability.

Reserves Determination

The proved crude oil, natural gas and NGLs reserves that are used in determining our depletion rates, the magnitude of the borrowing base available to us from our lender and the ceiling test are based on management's best estimates, and are subject to uncertainty. Through the use of geological, geophysical and engineering data, the reservoirs and deposits of crude oil, natural gas and NGLs are examined to determine quantities available for future production, given existing operations and economic conditions and technology. The evaluation of recoverable reserves is an ongoing process impacted by current production, continuing development activities and changing economic conditions as reflected in crude oil and natural gas prices. Consequently, the reserves are estimated, which are subject to variability. To assist with the reserves evaluation process, we employ the services of independent oil and gas reservoir engineers.

Income Taxes

The determination of our income and other tax liability requires interpretation of complex laws and regulations often involving multiple jurisdictions. All tax filings are subject to audit and potential reassessment after lapse of considerable time. Accordingly, the actual income tax liability may differ significantly from the liability estimated or recorded.

Other Estimates

The accrual method of accounting will require management to incorporate certain estimates including revenues, royalties and production costs as at a specific reporting date but for which actual revenue and royalties have not yet been received, and estimates on capital projects that are in progress or recently completed where actual costs have not been received at a specific reporting date.

Recent Accounting Pronouncements

As of January 1, 2007, the Company adopted the CICA's Handbook Section 1506 "Accounting Changes," Section 1530 "Comprehensive Income," Section 3251 "Equity," Section 3855 "Financial Instruments – Recognition and Measurement," Section 3861 "Financial Instruments – Disclosure and Presentation" and Section 3865 "Hedges." For a detailed discussion about the accounting policies adopted, please refer to note 2 of the financial statements for the three and nine-month periods ended September 30, 2007.

In addition, the Company has assessed new and revised accounting pronouncements that have been issued that are not yet effective and determined that the following may have a significant impact on the Company.

On December 1, 2006, the CICA issued three new accounting standards: Handbook Section 1535 "Capital Disclosures," Section 3862 "Financial Instruments – Disclosures" and Section 3863 "Financial Instruments – Presentation." These new standards are effective January 1, 2008. Section 1535 specifies the disclosure of (i) an entity's objectives, policies and processes for managing capital; (ii) quantitative data about what the entity regards as capital; (iii) whether the entity has complied with any capital requirements; and (iv) if it has not complied, the consequences of such non-compliance. The new Sections 3862 and 3863 replace Handbook Section 3861 "Financial Instruments – Disclosure and Presentation," revising and enhancing its disclosure requirements, and carrying forward unchanged its presentation requirements. These new sections place increased emphasis on disclosures about the nature and extent of risks arising from financial instruments and how the entity manages those risks. We are currently assessing the impact of these new standards on our financial statements.

In January 2006, the CICA Accounting Standards Board ("AcSB") adopted a strategic plan for the direction of accounting standards in Canada. As part of the plan, accounting standards in Canada for public companies are expected to converge with International Financial Reporting Standards ("IFRS") by the end of 2011. The Company continues to monitor and assess the impact of convergence of Canadian GAAP and IFRS.

Business Risks and Risk Mitigation

Our operations are subject to risks normally associated with the exploration, development, production and marketing of crude oil and natural gas. The most important of these risks are set out below, together with the strategies we employ to mitigate and minimize these risks.

Inherent Industry Risks – Risk of Failing to Discover Economic Reserve Additions

Our strategies include focusing on gas prone selected areas in Western Canada, utilizing a team of highly qualified professionals with expertise and experience in these areas, expanding operations in core areas, continuously assessing new exploration opportunities to complement existing activities and striving for a balance between higher risk exploratory drilling, lower risk development drilling and pursuing liquids rich gas reservoirs.

Financial Risk – Commodity Price Risk and Capital Expenditures Risk

Commodity prices are driven by supply, demand and market conditions outside our influence and control. We manage this risk by constantly monitoring the forecasted price given by aggregators. In addition, from time to time we will employ a commodity hedging program that has a primary goal of minimizing significant downward movements in commodity prices. In February 2007, the Company entered into a fixed price contract to sell 2,700 GJs/d of natural gas between March 1 and October 31, 2007 at a price of \$7.72/GJ to our current natural gas purchaser. Capital expenditures are a controllable risk and include cost control of individual capital items and the tracking of cumulative capital expenditures throughout the budget period. We manage capital expenditures by two separate tracking systems: a historical accounting system that records the actual costs and a perpetual forecasting model that is constantly updated based on real-time information.

It is likely that in the future we will be required to raise additional capital through debt and equity financings in order to fully realize our strategic goals and business plans. Our ability to raise additional capital will depend on a number of factors, such as general economic and market conditions that are beyond our control. If we are unable to obtain additional financing or to obtain it on favourable terms, we may be required to forego attractive business opportunities. We are committed to maintaining a strong balance sheet combined with a flexible capital expenditure program that can be adjusted to capitalize on or reflect acquisition opportunities or a tightening of liquidity sources if necessary.

We manage operational risks by employing skilled professionals utilizing leading-edge technology and conducting regular maintenance and training programs. We have an operational emergency response plan and an operational safety manual is currently being prepared. In addition, a comprehensive insurance program is maintained to mitigate risks and protect against significant losses where possible.

We operate in accordance with all applicable environmental legislation. We strive to maintain compliance with such regulations.

[signed]

STUART C. SYMON
Vice President Finance & Chief Financial Officer
October 31, 2007

BALANCE SHEETS

As at	September 30, 2007	December 31, 2006
<i>(000s) (unaudited)</i>	(\$)	(\$)
Assets		
Current		
Accounts receivable <i>(note 9)</i>	6,247	7,618
Prepaid expenses and other	187	330
Financial derivative instruments <i>(note 9)</i>	230	--
	6,664	7,948
Property and equipment <i>(note 3)</i>	108,826	79,124
	115,490	87,072
Liabilities and Shareholders' Equity		
Current		
Bank debt <i>(note 4)</i>	21,013	898
Accounts payable and accrued liabilities <i>(note 10)</i>	14,664	17,822
Asset retirement obligations <i>(note 5)</i>	664	305
	36,341	19,025
Future tax liability <i>(note 7)</i>	7,719	2,262
Asset retirement obligations <i>(note 5)</i>	592	441
	8,311	2,703
Commitments <i>(notes 9 & 11)</i>		
Shareholders' equity		
Share capital <i>(note 6)</i>	61,488	63,700
Contributed surplus <i>(note 6)</i>	2,124	1,136
Retained earnings	7,226	508
	70,838	65,344
	115,490	87,072

See accompanying notes to the financial statements.

On behalf of the Board of Directors,

[signed]

Timothy V. Dunne
Director

October 31, 2007

[signed]

John Gareau
Director

STATEMENTS OF OPERATIONS AND DEFICIT

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2007	2006	2007	2006
<i>(000s, except per share data) (unaudited)</i>	(\$)	(\$)	(\$)	(\$)
Revenue				
Liquids and gas revenues	12,351	4,388	41,742	9,864
Royalty expense, net of Alberta				
Royalty Tax Credit	(3,902)	(1,764)	(13,464)	(3,872)
Interest revenue	1	88	1	288
Unrealized gain (loss) on financial derivative instruments <i>(note 9)</i>	(421)	--	230	--
	8,029	2,712	28,5098	6,280
Expenses				
Operating	1,250	780	4,362	1,573
General and administrative	422	416	1,454	1,287
Interest	217	--	472	--
Stock-based compensation <i>(note 6(d))</i>	223	203	928	457
Depletion, depreciation and accretion	4,089	1,161	11,497	2,826
	6,201	2,560	18,713	6,143
Income before income taxes	1,828	152	9,796	137
Income taxes				
Future tax expense (recovery) <i>(note 7)</i>	603	91	3,078	(229)
Net income and comprehensive income	1,225	61	6,718	366
Retained earnings (deficit), beginning of period	6,001	(730)	508	(1,035)
Retained earnings (deficit), end of period	7,226	(669)	7,226	(669)
Net income per share <i>(note 6)</i>				
Basic	0.04	0.00	0.21	0.01
Diluted	0.04	0.00	0.20	0.01

See accompanying notes to the financial statements.

STATEMENTS OF CASH FLOWS

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2007	2006	2007	2006
(000s) (unaudited)	(\$)	(\$)	(\$)	(\$)
Cash provided by (used in):				
Operating activities				
Net income for the period	1,225	61	6,718	366
Add back non-cash items:				
Depletion, depreciation and accretion	4,089	1,161	11,497	2,826
Stock-based compensation	223	203	928	457
Unrealized gain (loss) on financial derivative instruments (note 9)	421	--	(230)	--
Future tax expense (recovery)	603	91	3,078	(229)
Funds from operations	6,561	1,516	21,991	3,420
Changes in non-cash working capital (note 8)	(1,782)	254	(9,659)	(5,533)
	4,779	1,770	12,332	(2,113)
Financing activities				
Issue of common shares, net of share issue expense	--	(38)	83	12,309
Increase in bank debt	8,273	349	20,115	349
Changes in non-cash working capital (note 8)	--	(74)	--	(108)
	8,273	237	20,198	12,550
Investing activities				
Property and equipment additions	(17,919)	(19,192)	(40,547)	(38,684)
Changes in non-cash working capital (note 8)	4,867	2,352	8,017	4,859
	(13,052)	(16,840)	(32,530)	(33,825)
Net increase (decrease) in cash and cash equivalents	--	(14,833)	--	(23,388)
Cash and cash equivalents – beginning of period	--	14,833	--	23,388
Cash and cash equivalents – end of period	--	--	--	--

See accompanying notes to the financial statements.

NOTES TO FINANCIAL STATEMENTS

September 30, 2007
(unaudited)

1 Nature of Operations

Angle Energy Inc. (the "Company") is a privately held company that was incorporated under the laws of Alberta on January 23, 2004 and commenced active oil and gas operations in Alberta in 2005. These interim unaudited financial statements focus on the Company's operations for the three and nine months ended September 30, 2007 and year ended December 31, 2006.

2. Summary of Significant Accounting Policies

These financial statements have been prepared in accordance with Canadian generally accepted accounting principles. Since the determination of many assets, liabilities, revenues and expenses is dependent on future events, the preparation of these financial statements requires the use of estimates and assumptions, which have been made with careful judgement. However, actual results could differ from estimated amounts. The financial statements have, in management's opinion, been properly prepared using careful judgement with reasonable limits of materiality and within the framework of the significant accounting policies summarized below.

(a) Property and Equipment

(i) Capitalized Costs

The Company follows the full cost method of accounting for its petroleum and natural gas operations. Under this method, all costs related to the exploration, development and production of petroleum and natural gas reserves are capitalized in a single Canadian cost centre. Costs include lease acquisition costs, geological and geophysical expenses, costs of drilling both productive and non-productive wells, production equipment costs, general and administrative costs and stock-based compensation directly related to exploration and development activities. Proceeds from the sale of properties are applied against capitalized costs, without any gain or loss being realized, unless such sale would alter the rate of depletion and depreciation by more than 20%. Office equipment is recorded at cost.

(ii) Depletion and Amortization

Petroleum and natural gas properties, net of estimated salvage or residual value, and estimated costs of future development of proved undeveloped reserves are depleted and amortized using the unit-of-production method based on estimated gross proved petroleum and natural gas reserves as determined by independent engineers. For depletion and amortization purposes, relative volumes of petroleum and natural gas production and reserves are converted at the energy equivalent conversion rate of six thousand cubic feet of natural gas to one barrel of crude oil.

Costs of unproved properties and seismic costs on undeveloped land are initially excluded from petroleum and natural gas properties for the purpose of calculating depletion. When proved reserves are assigned or the property or seismic is considered to be impaired, the costs of the property or seismic or the amount of the impairment is added to costs subject to depletion.

Office equipment is amortized over its estimated useful life at declining-balance rates between 20% and 50%.

2. Summary of Significant Accounting Policies (continued)

(a) Property and Equipment (continued)

(iii) Ceiling Test

In applying the full cost method, the Company calculates a ceiling test whereby the carrying value of property and equipment is compared to the sum of the undiscounted cash flows expected to result from the future production of proved reserves and the sale of unproved properties. Cash flows are based on third party quoted forward prices, adjusted for transportation and quality differentials. Should the ceiling test result in an excess of carrying value, the Company would then measure the amount of impairment by comparing the carrying amounts of property and equipment to an amount equal to the estimated net present value of future cash flows from proved plus probable reserves and the sale of unproved properties. The Company's risk-free interest rate is used to arrive at the net present value of the future cash flows. Any excess carrying value would be recorded as a permanent impairment.

(b) Asset Retirement Obligations

The Company recognizes the fair value of an Asset Retirement Obligation ("ARO") in the period in which it is incurred when a reasonable estimate of the fair value can be made. The fair value is determined through a review of engineering studies, industry guidelines and management's estimate on a site-by-site basis. The fair value of the estimated ARO is recorded as a liability, with a corresponding increase in the carrying amount of the related asset. The capitalized amount is depleted on the unit-of-production method based on gross proved reserves. The liability amount is increased each reporting period to reflect the passage of time with the corresponding amount charged to earnings as accretion expense. Actual costs incurred upon the settlement of the asset retirement obligation are charged against the asset retirement obligation to the extent of the liability recorded.

(c) Future Income Taxes

The Company follows the liability method of accounting for income taxes. Under this method, future income tax assets and liabilities are determined based on differences between financial reporting and income tax bases of assets and liabilities, and are measured using substantively enacted income tax rates and laws that will be in effect when the differences are expected to reverse. The effect on future income tax assets and liabilities of a change in income tax rates is recognized in net income in the period in which the change is substantively enacted. A valuation allowance is recorded to the extent that there is uncertainty regarding utilization of future tax assets.

(d) Joint Operations

Substantially all of the exploration and production activities of the Company are conducted jointly with others and these financial statements reflect only the Company's proportionate interest in such activities.

(e) Stock Options

Under the Company's stock option plan described in note 6(d), options to purchase common shares are granted to directors, officers, employees and consultants at current market prices. Stock-based compensation expense is recorded in the statement of operations and deficit for all options granted with a corresponding increase recorded as contributed surplus. Compensation expense is based on the estimated fair values at the time of the grant and the expense is recognized over the vesting term of the options. Upon the exercise of the stock options, consideration paid together with the amount previously recognized in contributed surplus is recorded as an increase in share capital. The Company has not incorporated an estimated forfeiture rate for stock options that will not vest; rather, the Company accounts for the forfeitures as they occur. In the event that vested options expire, previously recognized compensation expense associated with such stock options is not reversed. In the event that vested options are cancelled, previously recognized compensation expense associated with such stock options is reversed.

2. Summary of Significant Accounting Policies (continued)

(f) Flow-Through Shares

Periodically, the Company finances a portion of its exploration and development activities through the issuance of flow-through shares. Under the terms of the flow-through share issues, the tax attributes of the related expenditures are renounced to subscribers. Share capital is reduced and future tax liability is increased by the tax effected amount of the renounced tax deductions at the time of renouncement, which is when the related documentation is filed with the appropriate governmental agency and there is reasonable certainty that the expenditures will be incurred.

(g) Revenue Recognition

Revenue from the sale of crude oil, natural gas and natural gas liquids are recognized based on volume delivered at contractual delivery points and rates. The cost associated with the delivery, including operating, transportation and production-based royalty expenses are recognized in the same period in which the related revenue is earned and recorded. Alberta Royalty Tax Credits are netted against oil, natural gas and natural gas liquids royalties, however this program was discontinued effective January 1, 2007.

(h) Per Share Amounts

Basic income (loss) per share is computed by dividing net income (loss) by the weighted average number of common shares outstanding during the period. The treasury stock method is used to calculate diluted per share amounts whereby proceeds from the exercise of in-the-money stock options or warrants and unrecognized future stock-based compensation expense are assumed to be used to purchase common shares of the Company at the average market price during the period. Diluted per share amounts reflect the potential dilution that could occur if stock options or warrants to purchase common shares were exercised and converted to common shares.

(i) Measurement Uncertainty

The amount recorded for depletion and depreciation of petroleum and natural gas properties and the ceiling test calculation are based on estimates of gross proved reserves, production rates, commodity prices, future costs and other relevant assumptions. By their nature, these estimates are subject to measurement uncertainty and the effects on the financial statements of changes in such estimates in future years could be significant.

Inherent in the fair value calculation of asset retirement obligations are numerous assumptions and judgements, including the ultimate settlement amounts, inflation factors, credit adjusted discount rates, timing of settlement and changes in the legal and regulatory environments. To the extent future revisions to these assumptions impact the fair value of the existing asset retirement obligation liability, a corresponding adjustment is made to the property and equipment account.

On October 25, 2007, The Government of Alberta released the New Royalty Framework ("NRF"). The NRF was the government's response to a report issued September 18, 2007 by the Alberta Royalty Review Panel, which was commissioned by the provincial government to perform a review of the province's royalty system. The NRF addresses royalty changes on oil, natural gas and NGLs, which primarily affects Angle in relation to natural gas and NGLs. The Company's production is solely within the Province of Alberta. On January 1, 2009, Crown royalty rates for high volume natural gas wells (greater than 580 mcf/d) will be increased materially, but the final determination of royalty payable is sensitive to both natural gas prices and well production rates. Wells drilled to measured depths greater than 2,000 metres will qualify for a reduction in royalty payable. The majority of Angle's acreage has production targets that range in depth from 2,200 to over 2,700 metres. As a consequence, Angle's royalty payable will be reduced at production rates less than 1.0 mmcf/d. The amount of the royalty reduction will be dependent upon the measured drilled depth of the well, the rate of production and the price of natural gas.

(j) Change in Accounting Policies

As of January 1, 2007, the Company adopted the Canadian Institute of Chartered Accountants ("CICA") Handbook Section 1506 "Accounting Changes," Section 1530 "Comprehensive Income," Section 3251 "Equity," Section 3855 "Financial Instruments – Recognition and Measurement," Section 3861 "Financial Instruments - Disclosure and Presentation" and Section 3865 "Hedges."

2. Summary of Significant Accounting Policies (continued)

(j) Change in Accounting Policies (continued)

CICA Section 1506 "Accounting Changes" provides expanded disclosures for changes in accounting policies, accounting estimates and corrections of errors. Under the new standard, accounting changes should be applied retrospectively unless otherwise permitted or where impracticable to determine. As well, voluntary changes in accounting policy are made only when required by a primary source of GAAP or the change results in more relevant and reliable information.

CICA Section 1530 "Comprehensive Income" introduces a new requirement to temporarily present certain gains and losses from changes in fair value outside net income. It includes unrealized gains and losses, such as changes in currency translation adjustment relating to self-sustaining foreign operations, unrealized gains or losses on available-for-sale investments and the effective portion of gains or losses on derivatives designated as cash flow hedges. The application of this revised standard did not result in comprehensive income being different from the net income for the periods presented.

CICA Section 3855 "Financial Instruments – Recognition and Measurement" prescribes when a financial instrument is to be recognized on the balance sheet and at what amount. It also specifies how financial instrument gains and losses are to be presented. All financial instruments are classified into one of the following five categories: held-for-trading, held-to-maturity, loans and receivables, available-for-sale financial assets, and other financial liabilities. Initial and subsequent measurement and recognition of changes in the value of financial instruments depends on their initial classification.

- Held-to-maturity investments, loans and receivables, and other financial liabilities are initially measured at fair value and subsequently measured at amortized cost. Amortization of premiums or discounts and losses due to impairment are included in current period net earnings.
- Available-for-sale financial assets are measured at fair value. Revaluation gains and losses are included in other comprehensive income until the asset is removed from the balance sheet.
- Held for trading financial instruments are measured at fair value. All gains and losses are included in the net earnings in the period in which they arise.
- All derivative financial instruments are classified as held-for-trading financial instruments and are measured at fair value, even when they are part of a hedging relationship. All gains and losses are included in net earnings in the period which they arise.

The application of CICA Section 3855 did not have an impact on the Company's financial statements.

CICA Section 3865 "Hedges" provides alternative treatments to Section 3855 for entities that choose to designate qualifying transactions as hedges for accounting purposes. It replaces and expands on Accounting Guideline 13 "Hedging Relationships" and the hedging guidance in Section 1650 "Foreign Currency Translation" by specifying how hedge accounting is applied and what disclosures are necessary when it is applied. The Company currently uses mark-to-market accounting for its derivative instrument, which does not qualify or have not been designated as a hedge.

2. Summary of Significant Accounting Policies (continued)

(j) Change in Accounting Policies (continued)

In addition, the Company has assessed new and revised accounting pronouncements that have been issued that are not yet effective and determined that the following may have a significant impact on the Company:

- As of January 1, 2008, the Company will be required to adopt two new CICA standards, Section 3862 "Financial Instruments – Disclosures" and Section 3863 "Financial Instruments – Presentation," which will replace Section 3861 "Financial Instruments – Disclosure and Presentation." The new disclosure standard increases the emphasis on the risks associated with both recognized and unrecognized financial instruments and how those risks are managed. The new presentation standard carries forward the former presentation requirements. The new financial instruments presentation and disclosure requirements were issued in December 2006 and the Company is assessing the impact on its financial statements.
- As of January 1, 2008, the Company will be required to adopt the new CICA standard Section 1535 "Capital Disclosures," which will require companies to disclose their objectives, policies and processes for managing capital. In addition, disclosures are to include whether companies have complied with externally imposed capital requirements. The new capital disclosure requirements were issued in December 2006 and the Company is assessing the impact on its financial statements.
- In January 2006, the CICA Accounting Standards Board ("AcSB") adopted a strategic plan for the direction of accounting standards in Canada. As part of that plan, accounting standards in Canada for public companies are expected to converge with International Financial Reporting Standards ("IFRS") by the end of 2011. The Company continues to monitor and assess the impact of convergence of Canadian GAAP and IFRS.

3. Property and Equipment

	Cost	Accumulated Depletion and Depreciation	Net Book Value
(000s)	(\$)	(\$)	(\$)
September 30, 2007			
Petroleum and natural gas properties	125,690	16,959	108,731
Office equipment	148	53	95
	125,838	17,012	108,826
December 31, 2006			
Petroleum and natural gas properties	84,572	5,533	79,039
Office equipment	123	38	85
	84,695	5,571	79,124

For the nine months ended September 30, 2007, the Company capitalized \$194,000 of direct general and administrative costs (December 31, 2006 – \$390,000), \$143,000 including tax effect of \$42,000 of stock-based compensation expense (December 31, 2006 – \$156,000, including tax effect of \$73,000) and \$426,000 (December 31, 2006 – \$586,000) of operator overhead as related to the Company's exploration and development activity.

As at September 30, 2007, unevaluated and undeveloped properties with a cost of \$9,404,000 (December 31, 2006 – \$12,705,000) had not been subject to depletion as reserves related to these costs had not been evaluated or assigned. As at September 30, 2007, future development costs totaling \$5,043,000 (December 31, 2006 – \$9,083,000) were included subject to depletion.

The Company performed a ceiling test calculation at September 30, 2007 to assess the recoverable value of its petroleum and natural gas interests. It was determined that there was no impairment.

4. Revolving Bank Demand Loan

In May 2007, the Company established a revolving demand credit facility with a bank with a borrowing base of \$40,000,000 based on the Company's December 31, 2006 independent reserves report. The credit facility provides that advances may be made by way of direct advances or guaranteed notes. Direct advances bear interest at the bank's prime rate plus 0.25% and guaranteed notes bear interest at the applicable banker's acceptance rate plus 1.65%. Under the terms of the facility, certain financial covenants must be maintained. A general security agreement over all present and after acquired personal property and a floating charge on all lands has been provided as security. Subsequent to September 30, 2007, the Company has increased the revolving demand credit facility as disclosed in Note 12.

5. Asset Retirement Obligations

The Company records an asset retirement obligation associated with the present value of the estimated future cost to abandon its petroleum and natural gas properties. To determine the value of this obligation, the Company utilized an inflation rate of 2.0% and a credit adjusted risk-free interest rate of 8.0% to discount the future estimated cash flows of \$2,931,000, which is expected to be incurred over a period of 1 to 26 years. The obligation was as follows:

<i>(000s)</i>	<i>(\$)</i>
Balance – December 31, 2006	746
Change in estimates	(32)
Liabilities incurred	485
Accretion of asset retirement obligation	57
Balance – September 30, 2007	1,256
Less current portion	(664)
Long-term portion of asset retirement obligation – September 30, 2007	592

6. Share Capital

(a) Authorized

Unlimited number of common voting shares, no par value.

Unlimited number of preferred shares, no par value, issuable in series.

6. Share Capital (continued)

(b) Issued

	Nine Months Ended September 30, 2007		Year Ended December 31, 2006	
	Shares (#)	Amount (\$000s)	Shares (#)	Amount (\$000s)
Common Shares				
Balance – beginning of period	32,497,941	63,700	26,507,443	41,548
Common shares issued (i)	30,000	131	4,033,400	17,000
Flow-through shares (i)	--	--	1,611,100	8,000
Tax effect of flow-through shares (i)	--	(2,338)	--	(1,865)
Exercise of warrants (ii)	--	--	345,998	--
Share issue costs	--	(7)	--	(1,388)
Tax benefit of share issue costs	--	2	--	405
Balance – end of period	32,527,941	61,488	32,497,941	63,700
Warrants (ii)				
Balance – beginning of period	--	--	345,998	--
Warrants exercised in the period (ii)	--	--	(345,998)	--
Balance – end of period	--	--	--	--
Contributed Surplus				
Balance – beginning of period	--	1,136	--	379
Stock-based compensation expense – options	--	1,029	--	757
Reduction due to exercise of options	--	(41)	--	--
Balance – end of period	--	2,124	--	1,136

(i) Share Issuance

In January 2007, 30,000 common shares were issued at \$3.00 per share as a result of an exercise of stock options.

In December 2006, the Company issued 1,800,000 common shares at \$5.00 per share and 500,000 flow-through common shares at \$6.00 per share for total proceeds of \$12,000,000. Under the terms of the flow-through agreement, the Company is committed to spend \$3,000,000 on qualified exploration and development expenditures by December 31, 2007. As at March 31, 2007, the Company had satisfied this commitment and the tax liability was recognized in the first quarter of 2007 as the required documentation was filed with the applicable authorities.

In June 2006, the Company issued 1,733,400 common shares at \$3.75 per share and 1,111,100 flow-through common shares at \$4.50 per share for total proceeds of \$11,500,200. As at June 30, 2007, the Company was committed to spend \$4,999,500 on qualified exploration and development expenditures by December 31, 2007. As at December 31, 2006, the Company had satisfied this commitment and the tax liability was recognized in the last quarter of 2006 as the required documentation was filed with the applicable authorities.

In March 2006, the Company issued 500,000 common shares at \$3.00 per share to employees and directors for total proceeds of \$1,500,000.

6. Share Capital (continued)

(b) Issued (continued)

(ii) Warrant Issue and Exercise

In June 2004, the Company issued 6,920,000 units at a price of \$1.00 per unit for gross proceeds of \$6,920,000. The units consisted of one common share and one liquidity warrant. A total of 345,999 liquidity warrants were issued. Each liquidity warrant entitles the holder thereof to acquire a common share for no additional consideration in the event a liquidity event has not occurred by June 30, 2006. A liquidity event means either the common shares are not subject to any restrictions and are listed on either the TSX Venture Exchange or the Toronto Stock Exchange or all of the issued and outstanding common shares have been sold or exchanged pursuant to a takeover bid, plan of arrangement or other business combination.

No value has been ascribed to the liquidity warrants and the Company issued 345,999 common shares on the exercise of these warrants on June 30, 2006.

(c) Per Share

The net income per common share is calculated using the weighted average number of shares outstanding during the nine-month period ended September 30, 2007 of 32,526,293 basic and 33,798,058 diluted (September 30, 2006 – 27,949,052 basic and 28,212,561 diluted).

The net income per common share is calculated using the weighted average number of shares outstanding during the three months ended September 30, 2007 of 32,527,941 basic and 33,799,707 diluted (September 30, 2006 – 30,197,942 basic and 30,742,316 diluted).

(d) Options Outstanding

The Company has a stock option plan, administered by the Board of Directors, in which up to 10% of the issued and outstanding common shares are reserved for issuance for officers, employees, directors and consultants. Under the plan, options vest equally one third from the first year anniversary and expire at the earlier of the term set out in the particular option agreement or immediately from the date from which the optionee ceases to be a director, officer, employee or consultant of the Company or six months after the involuntary withdrawal of the optionee.

The following summarizes information about stock options outstanding as at September 30, 2007 and December 31, 2006:

	Options	Weighted Average Exercise Price
	(#)	(\$)
Outstanding at December 31, 2006	2,845,000	2.28
Granted in the period	185,000	3.90
Exercised in the period	(30,000)	3.00
Cancelled in the period	(130,000)	3.26
Outstanding at September 30, 2007	2,870,000	2.33

6. Share Capital (continued)

(d) Options Outstanding (continued)

Exercise Price (\$)	Outstanding (#)	Weighted Average Remaining Contractual Life (years)	Weighted Average Exercise Price (\$)	Exercisable (#)	Weighted Average Exercise Price (\$)
As at September 30, 2007					
1.00	1,205,000	2.1	1.00	1,091,645	1.00
3.00	1,050,000	3.2	3.00	386,657	3.00
3.75	430,000	3.9	3.75	156,667	3.75
3.90	185,000	4.8	3.90	--	3.90
	2,870,000	3.0	2.33	1,634,969	1.74

The fair value of common share options granted during the nine-month period ended September 30, 2007 was estimated to be \$492,000 or \$2.66 per weighted average option (2006 – \$1,702,000 or \$1.51 per weighted average option) as at the date of grant using the Black-Scholes option pricing model and the following assumptions:

	September 30, 2007	December 31, 2006
Risk-free interest rate (%)	4.50	4.50
Expected life (years)	5.00	5.00
Expected volatility (%)	45.00	45.00
Expected dividend yield (%)	0.00	0.00

During the first nine months of 2007, \$928,000 (2006 – \$457,000) was recognized as stock-based compensation expense and \$143,000, including tax effect of \$42,000 (2006 – \$84,000) was capitalized to the full cost pool in 2007 with a corresponding increase to contributed surplus.

7. Income Taxes

The actual income tax provision differs from the expected amount calculated by applying the Canadian combined federal and provincial corporate tax rates to income (loss) before income taxes. These differences are explained as follows:

7. Income Taxes (continued)

	Three Months Ended September,		Nine Months Ended September 30,	
	2007	2006	2007	2006
(000s)	(\$)	(\$)	(\$)	(\$)
Income (loss) before income tax	1,828	152	9,796	137
Tax rate	32.12%	34.50%	32.12%	34.50%
Computed income tax (recovery) provision	587	52	3,146	47
Increase (decrease) in income taxes resulting from:				
Non-deductible expenses	3	5	10	10
Alberta non-capital losses in excess of Federal losses	--	--	(73)	--
Crown royalties and charges	--	(17)	--	(14)
Resource allowance	--	(3)	--	(99)
Stock-based compensation	71	70	298	158
Rate adjustment	(58)	(16)	(303)	(331)
Provision for income tax expense (recovery)	603	91	3,078	(229)

Future income taxes reflect the net tax effects of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for income tax purposes. The components of the Company's net future income tax assets and liabilities are as follows:

As at	September 30, 2007	December 31, 2006
(000s)	(\$)	(\$)
Future income tax assets (liabilities)		
Non-capital losses carryforward	3,458	1,298
Share issue costs	595	780
Net book value of property and equipment in excess of tax basis	(12,080)	(4,565)
Unrealized gain on financial derivative instruments	(67)	--
Attributed Canadian royalty income	7	7
Asset retirement obligation	368	218
Future income tax asset (liability)	(7,719)	(2,262)

8. Changes in Non-Cash Working Capital

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2007	2006	2007	2006
(000s)	(\$)	(\$)	(\$)	(\$)
Accounts receivable	(459)	(1,206)	1,371	(1,753)
Prepaid expenses	44	50	144	(49)
Accounts payable and accrued liabilities	3,500	3,688	(3,157)	1,019
	3,085	2,532	(1,642)	(782)

The change in non-cash working capital has been allocated to the following activities:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2007	2006	2007	2006
(000s)	(\$)	(\$)	(\$)	(\$)
Operating	(1,782)	254	(9,659)	(5,533)
Financing	--	(74)	--	(108)
Investing	4,867	2,352	8,017	4,859
	3,085	2,532	(1,642)	(782)

9. Financial Instruments

Fair Value of Financial Assets and Liabilities

Financial instruments of the Company consist primarily of accounts receivable, financial derivative instruments, accounts payable and bank debt. As at September 30, 2007, there were no significant differences between the carrying amounts reported on the balance sheet and their estimated fair values due to the short-term nature of these instruments.

Credit Risk Management

Accounts receivable include amounts receivable for petroleum and natural gas sales that are generally made to credit-worthy purchasers, and amounts receivable from joint venture partners that are recoverable from production. Accordingly, management views credit risks on these amounts as low. Of significant individual accounts receivable at September 30, 2007, approximately 83% was owed from three customers (December 31, 2006 – 59% was owed from two customers). The Company has not experienced any material credit loss in the collection of receivables in the past.

Risk Management Activities:

The Company has entered into derivative financial instruments for the purpose of protecting a portion of its funds from operations from the volatility of natural gas commodity prices. The Company has not designated the derivatives as a hedge for accounting purposes and has therefore recorded the unrealized gains and losses on these contracts in the balance sheet as assets or liabilities with changes in their fair value recorded in net earnings for the period. Realized gains or losses from financial instruments related to commodity prices are recognized in the statement of income, comprehensive income and retained earnings (deficit) as the related sales occur.

As at September 30, 2007, the Company had recognized a financial derivative instrument asset of \$230,000 (December 31, 2006 – \$nil).

The following is a summary of all derivative contracts in place as at September 30, 2007:

Natural Gas	Volume	Pricing Point	Strike Price	Term
Fixed Price	2,700 GJ/d	AECO	CDN\$7.72	Mar.1/07 – Oct.31/07

10. Related Parties

During the nine months ended September 30, 2007, expenses and share issue costs were recorded totaling \$32,000 (2006 – \$144,000) that were charged to the Company by a legal firm of which a Director of the Company is a partner and \$nil (2006 – \$6,000) remained in accounts payable at period-end. This Director was previously a partner with a different legal firm for which expenses and share issue costs were recorded totaling \$nil (2006 – \$68,000) as at September 30, 2007. These amounts are recorded at the exchange amounts agreed to by the related parties.

11. Commitments

The Company has lease commitments for office premises and office equipment. In August 2007, we signed an amended office lease agreement to expand our lease space by approximately 3,000 square feet. The future annual minimum lease payments under the leases are as follows:

(000s)	(\$)
2007	95
2008	381
2009	381
2010	286
	<u>1,143</u>

12. Subsequent Events

In October 2007, the Company increased its revolving demand credit facility with a bank with a borrowing base of \$45,000,000 moving to \$50,000,000; the increase to \$50,000,000 can be attained by increasing the Company's production to approximately 3,800 boe/d. The increased credit facility provides that advances may be made by way of direct advances or guaranteed notes. Direct advances bear interest at the bank's prime rate plus 0.25% and guaranteed notes bear interest at the applicable bankers' acceptance rate plus 1.65%. Under the terms of the facility, certain financial covenants must be maintained. A general security agreement over all present and after acquired personal property and a floating charge on all lands has been provided as security.

In October 2007, the Company entered into a new derivative financial instrument for the purpose of protecting a portion of its funds from operations from the volatility of natural gas commodity prices.

The following is a summary of the new derivative contracts that have been executed and are effective beginning November 1, 2007:

Natural Gas	Volume	Pricing Point	Strike Price	Term
Fixed Price	1,600 GJ/d	AECO	CDN \$6.79/mcf	Nov.1/07 – Mar. 31/08
Costless Collar	1,500 GJ/d	AECO	CDN \$6.33 (floor) \$7.38/mcf (ceiling)	Nov.1/07 – Mar. 31/08

13. Basis of Presentation

Certain of the comparative figures have been reclassified to conform to the presentation adopted in the current period.

CORPORATE INFORMATION

Board of Directors

Gregg Fischbuch
President & Chief Executive Officer
Angle Energy Inc.

Noralee Bradley
Partner
Osler Hoskin & Harcourt LLP

Clarence Chow ⁽¹⁾ ⁽²⁾
President
AGS Capital Management Ltd.

John Gareau ⁽¹⁾
Independent Businessman

Edward Muchowski ⁽²⁾
Independent Businessman

Timothy Dunne ⁽¹⁾
Independent Businessman

(1) Audit Committee Member
(2) Reserves Committee Member

Officers

D. Gregg Fischbuch
President & Chief Executive Officer

Heather Christie-Burns
Vice President Engineering & Chief Operating Officer

Stuart C. Symon
Vice President Finance & Chief Financial Officer

Head Office

Suite 700
324 Eighth Avenue S.W.
Calgary, Alberta T2P 2Z2
Phone: (403) 263-4534
Fax: (403) 263-4179
Website: www.angleenergy.com

Auditors

Ernst & Young LLP

Banker

ATB Financial

Evaluation Engineers

GLJ Petroleum Consultants Ltd.

Legal Counsel

Osler Hoskin & Harcourt LLP

Transfer Agent

CIBC Mellon Trust Company

Abbreviations

bbls	barrels
bbls/d	barrels per day
bbls/mm	barrels per million
bcf	billion cubic feet
boe	barrels of oil equivalent
boe/d	barrels of oil equivalent per day
mbbls	thousand barrels
mboe	thousand barrels of oil equivalent
mcf	thousand cubic feet
mcf/d	thousand cubic feet per day
mmboe	million barrels of oil equivalent
mmcf	million cubic feet
mmcf/d	million cubic feet per day