
UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

- QUARTERLY REPORT UNDER SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the Quarter Ended September 30, 2009
- TRANSITION REPORT UNDER SECTION 13 OR 15(d) OF EXCHANGE ACT

Commission File No. 0-12185

NGAS RESOURCES, INC.

(Exact name of registrant as specified in its charter)

Province of British Columbia
(State or other jurisdiction of
incorporation or organization)

Not Applicable
(I.R.S. Employer
Identification No.)

120 Prosperous Place, Suite 201
Lexington, Kentucky
(Address of principal executive offices)

40509-1844
(Zip Code)

Registrant's telephone number, including area code: (859) 263-3948

(Former name or former address, if changed since the last report)

Indicate by check mark if the registrant (1) filed all reports required to be filed by Section 13 or 15(d) of the Act during the past 12 months and (2) has been subject to those filing requirements for the past 90 days. Yes No

Indicate by check mark if the registrant has submitted electronically and posted on its corporate website every indicative data file required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes No

Indicate by check mark if the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer or a smaller reporting company (as defined in Rule 12b-2 under the Exchange Act).

Large accelerated filer

Accelerated filer

Non-accelerated filer

Smaller reporting company

Indicate by check mark if the registrant is a shell company (as defined in Rule 12b-2). Yes No

Number of shares outstanding of each of the registrant's classes of common stock as of the latest practicable date.

Title of Class
Common Stock

Outstanding at November 1, 2009
30,484,361

NGAS RESOURCES, INC.

INDEX TO FORM 10-Q

PART I. FINANCIAL INFORMATION

	<u>Page</u>
Item 1. Financial Statements:	
Condensed Consolidated Balance Sheets – September 30, 2009 (unaudited) and December 31, 2008.....	1
Condensed Consolidated Statement of Operations – Three months and nine months ended September 30, 2009 and 2008	2
Condensed Consolidated Statement of Cash Flows – Three months and nine months ended September 30, 2009 and 2008	3
Notes to Condensed Consolidated Financial Statements	4
Item 2. Management’s Discussion and Analysis of Financial Condition and Results of Operations.....	10
Item 3. Quantitative and Qualitative Disclosures about Market Risk.....	20
Item 4. Controls and Procedures	21
PART II. OTHER INFORMATION	
Item 6. Exhibits.....	21

ADDITIONAL INFORMATION

We file annual, quarterly and other reports and information with the Securities Exchange Commission. Promptly after their filing, we provide access to these reports without charge on our website at www.ngas.com. Our principal and administrative offices are located in Lexington, Kentucky. Our common stock is traded on the Nasdaq Global Select Market under the symbol *NGAS*. Unless otherwise indicated, references in this report to the *company* or to *we*, *our* or *us* include NGAS Resources, Inc., our direct and indirect wholly owned subsidiaries and our interests in sponsored drilling partnerships. As used in this report, *Dth* means decatherm, *MMBtu* means million British thermal units, *Mcf* means thousand cubic feet, *Mcf_e* means thousand cubic feet of natural gas equivalents, *Mmcf* means million cubic feet, *Bcf* means billion cubic feet and *EUR* means estimated ultimately recoverable volumes of natural gas or oil.

NGAS RESOURCES, INC.

CONDENSED CONSOLIDATED BALANCE SHEETS

	September 30, 2009	December 31, 2008
ASSETS		
Current assets:		
	(Unaudited)	
Cash.....	\$ 970,467	\$ 981,899
Accounts receivable.....	5,372,800	10,450,173
Note receivable.....	6,124,570	—
Prepaid expenses and other current assets.....	869,224	540,253
Loans to related parties.....	<u>76,024</u>	<u>79,188</u>
Total current assets.....	13,413,085	12,051,513
Bonds and deposits.....	258,695	623,898
Note receivable.....	8,375,430	—
Oil and gas properties.....	181,158,605	229,218,344
Property and equipment.....	5,278,048	3,285,925
Loans to related parties.....	171,429	171,429
Deferred financing costs.....	1,439,399	1,689,580
Goodwill.....	<u>313,177</u>	<u>313,177</u>
Total assets.....	<u>\$210,407,868</u>	<u>\$247,353,866</u>
LIABILITIES		
Current liabilities:		
Accounts payable.....	\$ 5,092,604	\$ 12,362,092
Accrued liabilities.....	619,117	675,141
Deferred compensation.....	—	2,246,439
Customer drilling deposits.....	2,621,671	2,262,955
Long-term debt.....	<u>88,643</u>	<u>24,000</u>
Total current liabilities.....	8,422,035	17,570,627
Deferred compensation.....	497,650	—
Deferred income taxes.....	13,520,833	12,949,476
Long-term debt.....	74,046,866	108,580,448
Other long-term liabilities.....	<u>4,163,766</u>	<u>3,685,849</u>
Total liabilities.....	<u>100,651,150</u>	<u>142,786,400</u>
SHAREHOLDERS' EQUITY		
Capital stock		
<i>Authorized:</i>		
5,000,000 Preferred shares		
100,000,000 Common shares		
<i>Issued:</i>		
30,484,361 Common shares (2008 – 26,543,646).....	117,142,639	110,626,912
21,100 Common shares held in treasury, at cost.....	(23,630)	(23,630)
Paid-in capital – options and warrants.....	4,336,463	3,774,600
Contributed surplus.....	425,731	690,370
<i>To be issued:</i>		
9,185 Common shares (2008 – 9,185).....	<u>45,925</u>	<u>45,925</u>
	121,927,128	115,114,177
Deficit.....	<u>(12,170,410)</u>	<u>(10,546,711)</u>
Total shareholders' equity.....	<u>109,756,718</u>	<u>104,567,466</u>
Total liabilities and shareholders' equity.....	<u>\$210,407,868</u>	<u>\$247,353,866</u>

See accompanying notes.

NGAS RESOURCES, INC.

CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS

(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2009	2008	2009	2008
REVENUE				
Contract drilling.....	\$ 3,831,250	\$ 9,799,561	\$ 16,328,000	\$ 24,027,035
Oil and gas production	6,239,324	11,222,879	20,198,187	30,891,933
Gas transmission, compression and processing.....	<u>1,123,921</u>	<u>2,567,852</u>	<u>6,528,132</u>	<u>7,662,504</u>
Total revenue	<u>11,194,495</u>	<u>23,590,292</u>	<u>43,054,319</u>	<u>62,581,472</u>
DIRECT EXPENSES				
Contract drilling	2,913,418	7,570,698	12,328,110	18,447,544
Oil and gas production	2,658,985	3,922,629	7,598,044	9,794,679
Gas transmission, compression and processing.....	<u>960,879</u>	<u>1,039,597</u>	<u>2,955,204</u>	<u>3,087,391</u>
Total direct expenses	<u>6,533,282</u>	<u>12,532,924</u>	<u>22,881,358</u>	<u>31,329,614</u>
OTHER EXPENSES (INCOME)				
Selling, general and administrative	2,601,514	3,551,908	8,404,519	10,282,485
Options, warrants and deferred compensation ..	285,309	229,209	1,022,774	601,691
Depreciation, depletion and amortization	3,304,139	3,318,320	10,610,630	9,451,272
Bad debt expense	—	342,195	—	749,035
Interest expense.....	1,191,409	1,457,300	4,023,274	4,138,913
Interest income.....	(52,698)	(10,774)	(67,708)	(89,577)
Gain on sale of assets	(3,356,177)	—	(3,369,082)	—
Other, net.....	<u>292,073</u>	<u>87,584</u>	<u>600,896</u>	<u>115,939</u>
Total other expenses	<u>4,265,569</u>	<u>8,975,742</u>	<u>21,225,303</u>	<u>25,249,758</u>
INCOME (LOSS) BEFORE INCOME TAXES	395,644	2,081,626	(1,052,342)	6,002,100
INCOME TAX EXPENSE.....	<u>508,116</u>	<u>1,136,441</u>	<u>571,357</u>	<u>3,372,464</u>
NET INCOME (LOSS)	<u>\$ (112,472)</u>	<u>\$ 945,185</u>	<u>\$ (1,623,699)</u>	<u>\$ 2,629,636</u>
NET INCOME (LOSS) PER SHARE				
Basic	<u>\$ (0.00)</u>	<u>\$ 0.04</u>	<u>\$ (0.06)</u>	<u>\$ 0.10</u>
Diluted	<u>\$ (0.00)</u>	<u>\$ 0.04</u>	<u>\$ (0.06)</u>	<u>\$ 0.10</u>
WEIGHTED AVERAGE COMMON SHARES OUTSTANDING:				
Basic.....	<u>28,873,105</u>	<u>26,508,570</u>	<u>27,508,925</u>	<u>26,364,158</u>
Diluted	<u>28,873,105</u>	<u>26,977,438</u>	<u>27,508,925</u>	<u>27,019,313</u>

See accompanying notes.

NGAS RESOURCES, INC.

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

(Unaudited)

	Three Months Ended		Nine Months Ended	
	September 30,		September 30,	
	2009	2008	2009	2008
OPERATING ACTIVITIES				
Net income (loss)	\$ (112,472)	\$ 945,185	\$ (1,623,699)	\$ 2,629,636
Adjustments to reconcile net income (loss) to net cash provided by operating activities:				
Incentive bonus paid in common shares	65,001	228,120	426,251	259,690
Options, warrants and deferred compensation	285,309	229,209	1,022,774	601,691
Depreciation, depletion and amortization	3,304,139	3,318,320	10,610,630	9,451,272
Bad debt expense	—	342,195	—	749,035
Gain on sale of assets	(3,356,177)	(10,761)	(3,369,082)	(11,116)
Deferred income taxes	508,116	1,136,441	571,357	3,372,464
Changes in assets and liabilities:				
Accounts receivable	311,360	(1,840,648)	5,077,373	(5,983,968)
Prepaid expenses and other current assets ..	(353,376)	(345,152)	(328,971)	(227,538)
Other non-current assets	—	—	—	3,242,790
Accounts payable	(144,533)	2,979,900	(7,269,488)	3,684,584
Accrued liabilities	(46,040)	261,981	(56,024)	469,599
Deferred compensation	(2,094,700)	—	(2,209,700)	—
Customers' drilling deposits	1,923,271	(1,630,304)	358,716	(2,857,806)
Other long-term liabilities	155,091	—	477,917	—
Net cash provided by operating activities	<u>444,989</u>	<u>5,614,486</u>	<u>3,688,054</u>	<u>15,380,333</u>
INVESTING ACTIVITIES				
Proceeds from sale of assets	35,857,613	15,855	35,911,646	54,555
Purchase of property and equipment	(195,261)	(155,170)	(2,683,061)	(459,671)
Change in bonds and deposits	5,000	(95,250)	15,203	(130,750)
Additions to oil and gas properties, net	(3,841,799)	(11,615,165)	(7,918,894)	(37,940,322)
Net cash provided by (used in) investing activities	<u>31,825,553</u>	<u>(11,849,730)</u>	<u>25,324,894</u>	<u>(38,476,188)</u>
FINANCING ACTIVITIES				
Decrease in loans to related parties	890	1,861	3,164	4,538
Proceeds from issuance of common shares	6,089,476	81,200	6,089,476	1,190,006
Payments of deferred financing costs	(10,882)	(297,440)	(383,442)	(440,983)
Proceeds from issuance of long-term debt	—	5,500,000	—	22,240,000
Payments of long-term debt	(45,021,578)	(6,000)	(34,733,578)	(2,032,175)
Net cash provided by (used in) financing activities	<u>(38,942,094)</u>	<u>5,279,621</u>	<u>(29,024,380)</u>	<u>20,961,386</u>
Change in cash	(6,671,552)	(955,623)	(11,432)	(2,134,469)
Cash, beginning of period	<u>7,642,019</u>	<u>1,637,832</u>	<u>981,899</u>	<u>2,816,678</u>
Cash, end of period	<u>\$ 970,467</u>	<u>\$ 682,209</u>	<u>\$ 970,467</u>	<u>\$ 682,209</u>
SUPPLEMENTAL DISCLOSURE				
Interest paid	\$ 1,204,354	\$ 1,456,786	\$ 4,026,548	\$ 4,138,104
Income taxes paid	—	—	—	—

See accompanying notes.

NGAS RESOURCES, INC.

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

(Unaudited)

Note 1. Summary of Significant Accounting Policies

(a) General. The accompanying condensed consolidated financial statements of NGAS Resources, Inc. (NGAS) have been prepared in accordance with accounting principles generally accepted in the United States (U.S. GAAP). Our accounting policies are described in Note 1 to the consolidated financial statements in our annual report on Form 10-K for the year ended December 31, 2008. Our accounting policies and their method of application in the accompanying condensed consolidated financial statements are consistent with those described in the annual report.

(b) Basis of Presentation. The accompanying condensed consolidated financial statements include the accounts of NGAS, our wholly owned subsidiary, Daugherty Petroleum, Inc. (DPI), and its wholly owned subsidiaries. The condensed consolidated financial statements also reflect DPI's interests in a total of 39 drilling partnerships sponsored to participate in many of our drilling initiatives. We account for those interests using the proportionate consolidation method, with all material inter-company accounts and transactions eliminated on consolidation. References to the *company, we, our* or *us* include DPI, its subsidiaries and interests in sponsored drilling partnerships. These interim consolidated financial statements are unaudited but reflect all normal recurring adjustments that, in the opinion of our management, are necessary to fairly present our financial position at September 30, 2009 and results of operations and cash flows for the three months and nine months ended September 30, 2009 and 2008.

(c) Estimates. The preparation of financial statements in conformity with U.S. GAAP requires us to make estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities as of the date of the consolidated financial statements and the reported amounts of revenues and expenses during the reporting periods. The most significant estimates pertain to proved oil and gas reserves and related cash flow estimates used in impairment tests of goodwill and other long-lived assets, estimates of future development, dismantlement and abandonment costs and estimates relating to future oil and gas revenues and expenses. We also make estimates and assumptions in maintaining allowances for doubtful accounts when appropriate to reflect losses that could result from payment failures by our customers or counterparties. The evaluations required for these estimates involve significant uncertainties, and actual results could differ from the estimates.

Note 2. Oil and Gas Properties

(a) Sale of Appalachian Gas Gathering Facilities. On July 15, 2009, we sold a 50% undivided interest in 485 miles of our Appalachian gas gathering facilities (*Gathering System*) to Seminole Gas Company, L.L.C. (*Seminole*) for \$28 million. As part of the transaction, we entered into various joint ownership, gas marketing and gas sales arrangements with Seminole and its parent company, Seminole Energy Services, LLC (*Seminole Energy*). Under these arrangements, we retained operating rights for the Gathering System and firm capacity rights for daily delivery of 30,000 Mcf of controlled gas through the system. We also granted Seminole Energy a six-month option to purchase our retained 50% interest in the Gathering System for \$22 million, payable \$7.5 million at closing and the balance over 30 months under a promissory note bearing interest at 8% per annum. See Note 4 – Note Receivable. We reserved the right to require Seminole Energy to exercise its purchase option, conditioned on our completion of an equity offering for at least \$5 million. On August 17, 2009, after satisfying that condition, we closed the sale of our remaining interest in the Gathering System to Seminole Energy under the terms of its purchase option. See Note 9 – Capital Stock. All of our proceeds from the Gathering System sale were applied to debt reduction. See Note 8 – Long-Term Debt.

(b) Capitalized Costs and DD&A. All of our oil and gas development and producing activities are conducted within the continental United States. Capitalized costs and accumulated depreciation, depletion and amortization (DD&A) for our oil and gas properties, gathering facilities and well equipment as of September 30, 2009 and December 31, 2008 are summarized below. Capitalized costs and accumulated DD&A for our gathering system and well equipment at September 30, 2009 were reduced by \$51,571,070 and \$5,301,027, respectively, from our sale of the Gathering System during the third quarter of 2009.

	September 30, 2009	December 31, 2008
Proved oil and gas properties.....	\$ 197,922,674	\$ 192,186,676
Unproved oil and gas properties	5,209,182	5,065,835
Gathering facilities and well equipment	<u>17,421,334</u>	<u>67,326,445</u>
	220,553,190	264,578,956
Accumulated DD&A	<u>(39,394,585)</u>	<u>(35,360,612)</u>
Net oil and gas properties and equipment	<u>\$ 181,158,605</u>	<u>\$ 229,218,344</u>

(c) *Suspended Well Costs.* We had no suspended exploratory wells costs that were required to be expensed during 2008 or the first nine months of 2009 based on the criteria of FSP No. 19-1, *Accounting for Suspended Well Costs.*

Note 3. Property and Equipment

The following table presents the capitalized costs and accumulated depreciation for our other property and equipment as of September 30, 2009 and December 31, 2008.

	September 30, 2009	December 31, 2008
Land.....	\$ 12,908	\$ 12,908
Building improvements	64,265	64,265
Machinery and equipment	5,839,686	3,333,981
Office furniture and fixtures	175,862	175,862
Computer and office equipment	690,905	670,349
Vehicles	<u>1,811,276</u>	<u>1,951,279</u>
	8,594,902	6,208,644
Accumulated depreciation	<u>(3,316,854)</u>	<u>(2,922,719)</u>
Net other property and equipment.....	<u>\$ 5,278,048</u>	<u>\$ 3,285,925</u>

Note 4. Note Receivable

As part of the purchase price for the Gathering System, we received a promissory note issued by Seminole Energy on August 17, 2009 in the original principal amount of \$14.5 million. See Note 2 – Oil and Gas Properties. The note is payable in equal monthly installments through December 2011, with interest at 8% per annum. Performance of the note is secured by a second mortgage lien on Seminole Energy’s 50% interest in the Gathering System assets. We have assigned the note as part of the collateral package under our revolving credit facility and will apply all payments of principal and interest under the note to reduce our credit facility debt. See Note 8 – Long-Term Debt.

Note 5. Deferred Financing Costs

Financing costs for our convertible notes and revolving credit facility are initially capitalized and amortized at rates based on the terms of the underlying debt instruments. See Note 8 – Long-Term Debt. Upon conversion of convertible notes, the principal amount converted is added to equity, net of a proportionate amount of the original financing costs. Unamortized deferred financing costs for our outstanding notes and credit facility aggregated \$1,439,399 at September 30, 2009 and \$1,689,580 at December 31, 2008.

Note 6. Goodwill

Goodwill of \$1,789,564 was recorded in connection with our acquisition of DPI in 1993 and was amortized over ten years on a straight-line basis until 2002, when we adopted the Canadian equivalent of Financial Accounting Standards (SFAS) No. 142, *Goodwill and Other Intangible Assets.* Under the adopted standard, goodwill is no longer amortized but is instead tested for impairment at least annually. Our annual analyses indicated that no impairment charges were required. Accordingly, accumulated amortization of goodwill remained at \$1,476,387 as of September 30, 2009 and December 31, 2008, with unamortized goodwill of \$313,177.

Note 7. Customer Drilling Deposits

Net proceeds received under drilling contracts with sponsored partnerships and joint ventures are recorded as customer drilling deposits at the time of receipt. We recognize revenues from drilling operations on the completed contract method as the wells are drilled, rather than when funds are received. We had customer drilling deposits of \$2,621,671 at September 30, 2009 and \$2,262,955 at December 31, 2008, representing unapplied drilling contract payments for wells that were not yet drilled as of the balance sheet dates.

Note 8. Long-Term Debt

(a) Convertible Notes. We have an outstanding series of 6% convertible notes due December 15, 2010 in the aggregate principal amount of \$37 million. The notes are convertible into our common shares at a conversion price of \$11.16, reflecting an anti-dilution adjustment from our registered direct placement in August 2009. See Note 9 – Capital Stock. Upon any event of default under the notes or any change of control, we may be required to redeem the notes at specified premiums above their face amount. Notes that are neither redeemed nor converted prior to maturity will be repayable in cash or common shares, valued for that purpose at 92.5% of their market price.

(b) Credit Facility. We have a revolving credit facility maintained by DPI under a credit agreement with KeyBank National Association, as administrative agent. The facility provides for loans and letters of credit in an aggregate amount up to \$125 million, with a scheduled maturity in September 2011. Credit availability under the facility is subject to borrowing base limits, as determined semi-annually by the lenders. Interest is payable at fluctuating rates ranging from the agent’s prime rate to 2.25% above that rate, depending on borrowing base utilization. We are also responsible for commitment fees ranging from 0.375% to 0.5% of the unused borrowing base. The facility is guaranteed by NGAS and is secured by liens on DPI’s oil and gas properties.

As of September 30, 2009, we had outstanding borrowings of \$35 million under the facility, with a borrowing base of \$55 million. This reflects debt reductions totaling \$41.5 million from proceeds of our Gathering System sale and equity raise in the third quarter of 2009 and a borrowing base reduction of \$25 million in July 2009 from lower commodity prices and the release of our Gathering System assets from the collateral package. See Note 9 – Capital Stock. A related amendment to the credit agreement provides for the further debt reduction from payments under our note receivable issued by Seminole Energy as part of the purchase price for our Gathering System. See Note 4 – Note Receivable.

(c) Installment Loan. In June 2009, DPI obtained a \$2.3 million loan from Central Bank & Trust Co. to finance the balance of its commitment under an airplane purchase contract entered in 2005. The loan bears interest at 5.875% per annum and is repayable in monthly installments of \$16,428 over a three-year term, with the balance due at the end of the term, unless extended by the bank. The loan is secured by a lien on the airplane and had an outstanding balance of \$2,284,422 at September 30, 2009.

(d) Acquisition Debt. We issued a note for \$854,818 in 1986 to finance our acquisition of mineral property on Unga Island, Alaska. The debt is repayable without interest in monthly installments of \$2,000 and is secured by liens on the acquired property. The outstanding acquisition debt was \$276,818 at September 30, 2009.

(e) Total Long-Term Debt and Maturities. The following tables summarize our total long-term debt at September 30, 2009 and December 31, 2008 and the principal payments due each year through 2013 and thereafter.

<u>Principal Amount Outstanding</u>	September 30, 2009	December 31, 2008
Total long-term debt (including current portion) ⁽¹⁾	\$ 74,135,509	\$108,604,448
Less current portion	<u>88,643</u>	<u>24,000</u>
Total long-term debt	<u>\$ 74,046,866</u>	<u>\$108,580,448</u>

Maturities of Debt

Remainder of 2009	\$ 27,807
2010	36,663,866 ⁽¹⁾
2011	35,093,557
2012	2,157,461
2013 and thereafter	192,818

(1) Reflects allocations of \$425,731 at September 30, 2009 and \$690,370 at December 31, 2008 from our 6% convertible notes in the principal amount of \$37,000,000 based on equity components of their conversion features.

Note 9. Capital Stock

(a) *Preferred Shares.* We have 5,000,000 authorized shares of preferred stock, none of which were outstanding at September 30, 2009 or December 31, 2008.

(b) *Common Shares.* On August 13, 2009, we completed a registered direct placement of 3.48 million units under our existing shelf registration statement at \$1.90 per unit. Each unit consists of one share of our common stock and a warrant to buy 0.5 common share. The following table reflects the direct placement and other transactions involving our equity securities during the reported periods.

<u>Common Shares Issued</u>	<u>Number of Shares</u>	<u>Amount</u>
Balance, December 31, 2007	26,136,064	\$ 108,842,526
Issued to employees as incentive bonus	50,000	259,690
Issued upon exercise of stock options.....	<u>357,582</u>	<u>1,524,696</u>
Balance, December 31, 2008	26,543,646	110,626,912
Issued in registered direct placement.....	3,480,000	6,089,476
Issued as stock awards under incentive plan.....	460,715	426,251
Balance, September 30, 2009.....	<u>30,484,361</u>	<u>\$ 117,142,639</u>
<u>Paid In Capital – Options and Warrants</u>		
Balance, December 31, 2007		3,484,148
Recognized		625,142
Exercised		<u>(334,690)</u>
Balance, December 31, 2008		3,774,600
Recognized		<u>561,863</u>
Balance, September 30, 2009.....		<u>\$ 4,336,463</u>
<u>Contributed Surplus</u>		
Balance, December 31, 2007		\$ 1,043,222
Accreted ⁽¹⁾		<u>(352,852)</u>
Balance, December 31, 2008		690,370
Accreted ⁽¹⁾		<u>(264,639)</u>
Balance, September 30, 2009.....		<u>\$ 425,731</u>
<u>Common Shares to be Issued</u>		
Balance, September 30, 2009 and December 31, 2008.....	<u>9,185</u>	<u>\$ 45,925</u>

(1) Reflects accretion of the equity components allocated to our 6% convertible notes and related warrants issued in 2005.

(c) *Stock Options and Awards.* We maintain three equity incentive plans for the benefit of our directors, officers, employees and certain consultants. The plans provide for the grant of options to purchase up to 3.6 million common shares and, in the case of our most recent plan, either stock awards or options for an aggregate of up to 4 million common shares. Stock awards under the third plan may be subject to restrictions, and option grants under all three plans must be at prevailing market prices and may be subject to vesting requirements. Stock awards were made for a total of 460,715 shares during the first nine months of 2009 and 50,000 shares during 2008. Transactions in stock options during those periods are shown in the following table.

	<u>Issued</u>	<u>Exercisable</u>	<u>Weighted Average Exercise Price</u>
Balance, December 31, 2007	2,681,250	1,739,583	\$ 4.75
Granted	2,300,000	—	2.93
Vested	—	41,667	6.02
Exercised	(357,582)	(357,582)	3.33
Forfeited	<u>(10,000)</u>	<u>(10,000)</u>	7.04
Balance, December 31, 2008	4,613,668	1,413,668	3.95
Vested	—	1,225,000	4.69
Expired	<u>(740,000)</u>	<u>(740,000)</u>	4.06
Balance, September 30, 2009.....	<u>3,873,668</u>	<u>1,898,668</u>	3.92

At September 30, 2009, the exercise prices of options outstanding under our equity plans ranged from \$1.51 to \$7.64 per share, and their weighted average remaining contractual life was 3.06 years. The following table provides additional information on the terms of stock options outstanding at September 30, 2009.

<u>Options Outstanding</u>				<u>Options Exercisable</u>	
<u>Exercise Price or Range</u>	<u>Number</u>	<u>Weighted Average Remaining Life (years)</u>	<u>Weighted Average Exercise Price</u>	<u>Number</u>	<u>Weighted Average Exercise Price</u>
\$ 1.51	1,650,000	5.61	\$ 1.51	—	\$ —
4.03	800,000	0.41	4.03	800,000	4.03
6.02 7.64	<u>1,423,668</u>	1.61	6.66	<u>1,098,668</u>	6.70
	<u>3,873,668</u>			<u>1,898,668</u>	

In accounting for stock options, we apply the fair value recognition provisions of SFAS No. 123(R), *Share-Based Payment*. We use the Black-Scholes pricing model to determine the fair value of each stock option at the grant date, and we recognize the compensation cost ratably over the vesting period. For the periods presented in the interim consolidated financial statements, the fair value estimates for each option grant assumed a risk free interest rate ranging from 0.03% to 6%, no dividend yield, a theoretical volatility ranging from 0.30 to 0.85 and an expected life ranging from three months to six years based on the vesting provisions of the options. This resulted in non-cash charges for options and warrants of \$625,142 in 2008 and \$561,863 in the first nine months of 2009.

(d) *Common Stock Purchase Warrants*. As part of our registered direct equity placement on August 13, 2009, we issued warrants to purchase 1.74 million shares of our common stock at \$2.35 per share, subject to adjustment for certain dilutive issuances. The warrants will be exercisable for four years, beginning six months after issuance.

Note 10. Income (Loss) Per Share

The following table shows the computation of basic and diluted earnings (loss) per share (*EPS*) for the reporting periods.

	<u>Three Months Ended</u>		<u>Nine Months Ended</u>	
	<u>September 30,</u>		<u>September 30,</u>	
<u>Numerator:</u>	<u>2009</u>	<u>2008</u>	<u>2009</u>	<u>2008</u>
Net income (loss) as reported for basic EPS.....	\$ (112,472)	\$ 945,185	\$ (1,623,699)	\$ 2,629,636
Adjustments to income (loss) for diluted EPS.....	—	—	—	—
Net income (loss) for diluted EPS.....	<u>\$ (112,472)</u>	<u>\$ 945,185</u>	<u>\$ (1,623,699)</u>	<u>\$ 2,629,636</u>
<u>Denominator:</u>				
Weighted average shares for basic EPS.....	28,873,105	26,508,570	27,508,925	26,364,158
Effect of dilutive securities – options/warrants	—	468,868	—	655,155
Adjusted weighted average shares and assumed conversions for diluted EPS	<u>28,873,105</u>	<u>26,977,438</u>	<u>27,508,925</u>	<u>27,019,313</u>
Basic EPS.....	<u>\$ (0.00)</u>	<u>\$ 0.04</u>	<u>\$ (0.06)</u>	<u>\$ 0.10</u>
Diluted EPS.....	<u>\$ (0.00)</u>	<u>\$ 0.04</u>	<u>\$ (0.06)</u>	<u>\$ 0.10</u>

Note 11. Segment Information

We have a single reportable operating segment for our oil and gas business based on the integrated way we are organized by management in making operating decisions and assessing performance. Although our financial reporting reflects our separate revenue streams from drilling, production and transmission activities and the direct expenses for each component, we do not consider the components as discreet operating segments under SFAS No. 131, *Disclosure about Segments of an Enterprise and Related Information*.

Note 12. Commitments

(a) *General.* We incurred operating lease expenses of \$2,583,417 in 2008 and \$2,024,745 in the first nine months of 2009. As of September 30, 2009, we had future obligations under operating leases in the amounts listed below.

Maturities of Lease Obligations

Remainder of 2009.....	\$ 604,704
2010	2,350,495
2011	2,095,224
2012	847,442
2013 and thereafter.....	<u>73,284</u>
Total	<u>\$ 5,971,149</u>

(b) *Gas Gathering and Sales Commitments.* We have various long-term commitments under our gas gathering and sales agreements entered with Seminole and Seminole Energy in connection with our sale of the Gathering System during the third quarter of 2009. These include (i) base monthly gathering fees of \$850,000, with annual escalations at the rate of 1.5%, (ii) base monthly operating fees of \$175,000, plus \$0.20 per Mcf of purchased gas, and (iii) monthly capital fees in amounts intended to yield a 20% internal rate of return for all capital expenditures on the Gathering System by Seminole and Seminole Energy. These agreements have an initial term of fifteen years with extension rights.

Note 13. Recent Accounting Standards

SFAS No. 168. In July 2009, the FASB issued SFAS No. 168, *Accounting Standards Codification and the Hierarchy of Generally Accepted Accounting Principles*. Effective for financial statements covering periods ending after September 15, 2009, the Codification changes the references to existing accounting pronouncements, superseding all prior accounting standards under U.S. GAAP, aside from those issued by the SEC. The guidance currently provided in the Codification has not had any impact on our consolidated financial statements.

Oil and Gas Reporting Requirements. In December 2008, the SEC amended its oil and gas reporting rules under the Exchange Act and Industry Guides. The revisions are intended to provide investors with a more meaningful and comprehensive understanding of oil and gas reserves by aligning the oil and gas disclosure requirements with current industry practices and technology. The amendments will be effective for fiscal years ending on or after December 31, 2009 and will significantly impact reserve and resource reporting for all E&P companies.

NGAS RESOURCES, INC.

Item 2.

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

General

We are an independent exploration and production company focused on unconventional natural gas plays in the eastern United States, principally in the southern portion of the Appalachian Basin. We have specialized for over 20 years in generating our own geological prospects in this region, where we have established expertise and recognition. During the last two years, we have successfully transitioned to horizontal drilling and extended our operations to the Illinois Basin. We believe our extensive operating experience, coupled with our relationships with partners, suppliers and mineral interest owners, gives us competitive advantages in developing these resources to achieve sustained volumetric growth and strong financial returns on a long-term basis.

Recent Developments

Liquidity from Gathering System Sale and Equity Raise. On July 15, 2009, we sold a 50% undivided interest in 485 miles of our Appalachian gas gathering facilities (*Gathering System*) to Seminole Gas Company, L.L.C. (*Seminole*) for \$28 million. As part of the transaction, we entered into various gas marketing and gas sales arrangements with Seminole and its parent company, Seminole Energy Services, LLC (*Seminole Energy*). Under these arrangements, we retained operating rights for the Gathering System and firm capacity rights for daily delivery of 30,000 Mcf of controlled gas, ensuring long-term deliverability for our Appalachian production through the system. We also granted Seminole Energy a six-month option to purchase our retained 50% interest in the Gathering System for \$22 million, payable \$7.5 million in cash and the balance over 30 months under a promissory note bearing interest at 8% per annum. We reserved the right to trigger the exercise of the purchase option, conditioned on our completion of a qualifying equity offering. On August 17, 2009, after satisfying that condition, we closed the sale of our remaining interest in the Gathering System to Seminole Energy under the terms of its purchase option. Proceeds of \$35.5 million from the Gathering System sale and approximately \$6.1 million from the equity raise were applied to debt reduction under our revolving credit facility. Liquidity from these transactions has provided us with greater flexibility to take advantage of our development opportunities.

Expansion of Leatherwood Position. In October 2009, we expanded our position in our key Leatherwood field with the acquisition of a lease covering 10,300 gross (8,280 net) undeveloped acres in Leslie and Harlan Counties, Kentucky. The lease provides the mineral interest owner with participation rights for up to 50% of the working interest in wells drilled on the covered acreage and requires us to drill at least three horizontal wells by the end of March 2011, followed by a two-well annual drilling commitment. Combined with the farmout we acquired earlier in the year from Chesapeake Appalachia, LLC for a significant tract next to the Amvest portion of our Stone Mountain field in Letcher and Harlan Counties, Kentucky, this brings our holdings in the Appalachian Basin to a total of 339,000 gross (241,000 net) acres.

Business Strategy

Over 70% of our properties in the Appalachian Basin are undeveloped, along with most of our assembled acreage in the Illinois Basin. Our business is structured for efficient development of these unconventional resource plays, which have been transformed by our use of horizontal drilling throughout our operating areas. We began this transition early in 2008 and had 20 horizontal wells on line at year-end, with an additional five horizontals producing to sales at the end of September 2009. Our success with these initiatives contributed to growth in our production volumes to 3.7 Bcfe in 2008, up 13% over 2007. Despite substantially reduced drilling activity this year, we produced 997 Mmcf of natural gas equivalents in the third quarter of 2009. This represents a 5% increase from the same quarter last year, but a 4% decline from record production volumes in the 2009 first quarter. Having strengthened our balance sheet with added liquidity in the third quarter, our extensive inventory of horizontal drilling locations positions us for future growth under a sustainable, low-cost structure with several components.

- *Organic Growth through Drilling with Reduced Capital Spending.* While we are committed to a long-term strategy of developing our reserves through the drillbit and retaining most of our available working interest in new wells, we have addressed the challenging conditions in our industry by reducing our 2009 capital spending budget to \$15 million and returning to our successful partnership structure for sharing development costs on operated properties. We raised over \$34 million for a non-operated program last year through our established sales network. To meet our near-term drilling commitments and objectives, we are currently sponsoring a partnership to participate in up to 53 horizontal wells throughout our operated

properties. The partnership commenced operations following an initial closing of its private placement in June 2009. We are maintaining a 20% interest in this year's program and will earn an additional 15% reversionary interest after program payout.

- Horizontal Drilling Initiatives. Recent advances in horizontal drilling and completion technology have enhanced the value proposition for our operated properties by substantially increasing our recovery volumes and rates at dramatically lower finding costs. Horizontal drilling also gives us access to areas where natural gas development would otherwise be delayed or constrained by coal mining activity or challenging terrain. We focused these initiatives during 2008 in our Leatherwood field, where we completed 20 horizontal wells last year. Each well has a single lateral leg up to 3,500 feet through the Devonian shale formation, which is present throughout our Appalachian operating areas. Initial 30-day flow rates for our Leatherwood horizontals averaged 309 Mcf per day. We achieved comparable results for our first two New Albany shale horizontals drilled late in 2008 on our Illinois Basin acreage and our initial Devonian shale horizontals completed this year in our Straight Creek, Fonde and Martin's Fork fields. We plan to continue this transition throughout our operated properties, including 25 horizontal wells planned this year in Leatherwood.
- Advantages from Restructured Infrastructure Position. Although the sale of our Gathering System during the third quarter of 2009 eliminated the closed-access status for most of our field-wide infrastructure, we retained long-term capacity rights for the system, currently established at 30,000 Mcf per day. This ensures continued deliverability from our operated Appalachian properties serviced by these facilities. We also retained operating rights for the Gathering System, which provides deliverability from 90% of our Appalachian properties directly from the wellhead to major east coast natural gas markets through an interconnect with Spectra Energy Partners' East Tennessee Interstate pipeline network. Our operating and capacity rights also preserve our competitive advantages from control of regional gas flow, enhancing our opportunities to acquire undeveloped acreage near our core producing fields upon completion of coal mining activities. We continue to own a 50% interest in a liquids extraction plant for production serviced by the Gathering System, located in Rogersville, Tennessee. This is within 5.5 miles of the proposed site for a 880-megawatt gas-fired power plant to be constructed by the Tennessee Valley Authority, which may provide us with opportunities for long-term gas sales arrangements.

Drilling Operations

General. As of September 30, 2009, we had interests in over 1,400 wells, concentrated on our Appalachian properties. We believe our long and successful operating history and proven ability to drill a large number of wells year after year have positioned us as a leading producer in this region. Historically, we conducted most of our drilling operations through sponsored drilling partnerships with outside investors, enabling us to assemble our acreage positions on the strength of our drilling commitments, while also funding infrastructure development on acquired acreage for our own account. Beginning in the second half of 2007, with our core Appalachian infrastructure in place, we changed our business model to limit our use of drilling partnerships to participation in non-operated plays, retaining all of our available working interest in wells drilled on operated properties through the end of 2008. To address part of the capital requirements for meeting this year's drilling commitments and objectives, we are sponsoring a drilling partnership for up to \$53.1 million to participate in our horizontal wells during 2009 and the first quarter of 2010. The partnership commenced operations in June 2009 following the initial closing of its private placement.

Geological Factors. Although mineral development in Appalachia has historically been dominated by coal mining interests, it is also one of the oldest and most prolific natural gas producing areas in the United States. Most of our vertical wells in this region were drilled to relatively shallow total depths averaging 4,500 feet, generally encountering several predictable natural gas pay zones. The primary pay zone throughout our Appalachian acreage is the Devonian shale formation. This is considered an unconventional target due to its low permeability, requiring effective treatment to enhance natural fracturing in these reservoirs. Estimated ultimately recoverable volumes (EURs) of natural gas reported for vertical gas wells in this part of Appalachia range between 100 to 450 Mmcf, with modest initial volumes offset by low annual decline rates, resulting in a reserve life index of over 25 years. Our New Albany shale play in the Illinois Basin has similar geological, production and reserve characteristics.

Horizontal Drilling. Air-driven horizontal drilling advances and staged completion technology optimized for our operating areas have dramatically improved the economics of our shale plays in the Appalachian and Illinois Basins. In general, our horizontal wells use directional air drilling to create a lateral leg up to 3,500 feet through the target formation. This allows the well bore to stay in contact with the reservoir longer and to intersect more fractures in the formation than conventional vertical wells. While up to four times more expensive than vertical wells, horizontal drilling is improving overall performance by increasing recovery volumes and rates, limiting the number of wells necessary to develop an area through conventional drilling and reducing the costs and surface disturbances of multiple vertical wells. Typically, one horizontal well replaces between three to four vertical locations, reducing the total footprint by drilling fewer wells. Additional economies are being achieved with multiple horizontal wells on a single drilling location. In addition to these operational advantages, the initial recovery rates for our horizontals are averaging six to eight times the rates for vertical Devonian shale wells in the same fields. Although not fully reflected in our 2008 year-end reserve estimates, we anticipate substantial upside in both production and EURs from our ongoing transition to horizontal drilling.

Staged Completion Technology. Upon completion of drilling the lateral leg of our horizontal wells, we run 4.5-inch casing and packers to the end of the leg. The packers are set at intervals, allowing the well to be completed in up to eight separate stages within the horizontal leg. A staged treatment process is then performed on our horizontal wells to enhance natural fracturing with large volumes of nitrogen, generally over one-million standard cubic feet per stage. After the well is blown back for approximately seven days, it is connected to our existing field-wide gathering facilities to commence gas sales.

New Albany Shale Play. In addition to the recent expansion of our Leatherwood acreage and our Chesapeake farmout, we are continuing to develop our New Albany shale play within the southcentral portion of the Illinois Basin in western Kentucky. We began producing this project to sales in September 2008 upon completion of our gas gathering and processing infrastructure for the acreage, with a total of 33 wells on line at September 30, 2009. Based on encouraging results from our New Albany shale horizontals, we have expanded our lease position and plan to drill up to five horizontal wells on this acreage through our 2009 drilling partnership.

Drilling Results. The following table shows the number of gross and net development and exploratory wells we drilled during 2008 and the first nine months of 2009. Drilling results shown in the table for 2008 include 55 gross (24.18 net) wells that were drilled by year-end but were awaiting installation of gathering lines or extensions prior to completion, primarily on non-operated properties. Gross wells are the total number of wells in which we have a working interest. Net wells reflect our working interests, without giving effect to any reversionary interest we may subsequently earn in wells drilled through our sponsored drilling programs.

Year Ended December 31, 2008	Development Wells			Exploratory Wells		
	Productive		Dry	Productive		Dry
	Gross	Net	Gross	Gross	Net	Gross
Vertical.....	137	58.8522	—	9	8.8125	—
Horizontal	47	15.7254	—	—	—	—
Total	184	74.5776	—	9	8.8125	—
Nine Months Ended September 30, 2009						
Vertical.....	10	1.6972	—	—	—	—
Horizontal	14	2.7588	—	—	—	—
Total	24	4.4560	—	—	—	—

Producing Activities

Regional Advantages. Our proved reserves, both developed and undeveloped, are concentrated in the southern portion of the Appalachian Basin. The proximity of this region to major east coast gas markets reduces our transportation costs, generating realization premiums above Henry Hub spot prices and contributing to long-term returns on investment. Our Appalachian gas production also has the advantage of a high energy content (*Dth*), ranging from 1.1 to 1.3 Dth per Mcf. Historically, because our gas sales contracts yield upward adjustments from index based pricing for throughput with an energy content above 1 Dth per Mcf, this resulted in realized premiums averaging 17% over normal pipeline quality gas.

Liquids Extraction. During 2007, in response to regulatory tariffs limiting the upward range of pipeline throughput to 1.1 Dth per Mcf, we constructed a processing plant with Seminole Energy in Rogersville, Tennessee for liquids extraction from our Appalachian production delivered through the Gathering System. The plant was brought on line in February 2008, ensuring our compliance with the new energy content standard. Sales of extracted natural gas liquids (NGL) have partially offset the reduction in energy-related yields from our Appalachian gas production. In addition, our margins for sales of extracted NGL have benefited from lower hauling costs achieved through recently implemented rail shipping arrangements.

Oil and Gas Production. Our production revenues and estimated oil and gas reserves are substantially dependent on prevailing market prices for natural gas, which comprised 78% of our proved reserves on an energy equivalent basis at the end of 2008. The following table shows the average sales prices for our natural gas, crude oil and NGL production during 2008 and the interim reporting periods.

	Three Months Ended September 30,		Nine Months Ended September 30,		Year Ended December 31,
	2009	2008	2009	2008	2008
Production volumes:					
Natural gas (Mcf).....	816,393	760,401	2,521,223	2,268,929	3,087,596
Oil (Bbl).....	11,887	16,235	37,313	44,718	57,291
Natural gas liquids (gallons).....	<u>1,458,541</u>	<u>1,202,292</u>	<u>3,895,199</u>	<u>2,930,974</u>	<u>3,895,649</u>
Equivalents (Mcf).....	<u>997,103</u>	<u>947,986</u>	<u>3,037,238</u>	<u>2,778,668</u>	<u>3,745,124</u>
Average sales prices:					
Natural gas (per Mcf)	\$ 5.67	\$ 9.80	\$ 6.31	\$ 9.40	\$ 8.89
Oil (per Bbl)	60.76	110.26	48.03	106.06	95.07
Natural gas liquids (per gallon)	0.61	1.65	0.64	1.64	1.41

Future Gas Sales Contracts. We use fixed-price, fixed-volume physical delivery contracts that cover portions of our natural gas production at specified prices during varying periods of time to address commodity price volatility. Our physical delivery contracts are not treated as financial hedging activities and are not subject to mark-to-market accounting. The financial impact of these contracts is included in our oil and gas revenues at the time of settlement. As of the date of this report, we have contracts in place for the following portions of our anticipated natural gas production for each quarter of 2010 and the fourth quarter of 2009.

FIXED-PRICE CONTRACTS FOR NATURAL GAS PRODUCTION

	2009	2010			
	Q4	Q1	Q2	Q3	Q4
Percentage of gas contracted	54%	58%	46%	51%	47%
Average price per Mcf	\$ 7.83	\$ 7.54	\$ 6.42	\$ 6.51	\$ 6.56

Results of Operations – Three Months Ended September 30, 2009 and 2008

Revenues. The following table shows the components of our revenues for the three months ended September 30, 2009 and 2008, together with their percentages of total revenue in the current period and percentage change on a period-over-period basis.

Revenue:	Three Months Ended September 30,			
	2009	% of Revenue	2008	% Change
Contract drilling.....	\$ 3,831,250	34%	\$ 9,799,561	(61)%
Oil and gas production.....	6,239,324	56	11,222,879	(44)
Gas transmission, compression and processing	<u>1,123,921</u>	<u>10</u>	<u>2,567,852</u>	(56)
Total	<u>\$ 11,194,495</u>	<u>100%</u>	<u>\$ 23,590,292</u>	(53)

Our total revenues for the third quarter of 2009 reflect the impact of declining commodity prices, reduced drilling activity and our sale of the Gathering System. In view of our reduction in capital expenditures for 2009, we do not expect this trend to reverse without a significant recovery in commodity prices and an increase in the level of drilling activity, which is directly linked to partnership sales under our current business model. Although sales of partnership interests are typically concentrated in the fourth quarter, they may continue to be impacted this year by the challenging economic environment.

Contract drilling revenues reflect the size and timing of our drilling partnership initiatives. Although we receive the proceeds from private placements in sponsored partnerships as customers' drilling deposits under our program drilling contracts, we recognize revenues from the interests of outside investors in these programs on the completed contract method as the wells are drilled, rather than when funds are received. Our contract drilling revenues in the third quarter of 2009 reflect continued operations of our 2009 drilling partnership, which participated in six horizontal wells during the quarter. We plan to drill a total of up to 53 horizontals on our operated properties through that program, depending on the level of partnership participation.

Production revenues for the third quarter of 2009 reflect an increase of 5% in production output to 997 Mmcfe, compared to 948 Mmcfe in the year-earlier period, offset by declines of 42% in natural gas prices, 45% in oil prices and 63% for sales of natural gas liquids. Our volumetric growth reflects strong performance from our horizontal wells and the commencement of production from our Haley's Mill field in western Kentucky during August 2008, along with our share of production from non-operated wells drilled for our 2008 drilling partnership. Approximately 50% of our natural gas production in the current quarter was sold under fixed-price physical delivery contracts, and the balance primarily at prices determined monthly under formulas based on prevailing market indices. Realized natural gas prices in the 2009 third quarter averaged \$6.53 per Mcf for our Appalachian production and \$5.67 per Mcf overall, compared to an average overall realization of \$9.80 per Mcf in the third quarter of 2008.

The contraction of gas transmission, compression and processing revenues for the current quarter was driven our sale of a 50% interest in the Gathering System in mid-July and the balance in mid-August 2009. See "Recent Developments." Following the sale, our gas transmission, compression and processing revenues were limited primarily to gas utility sales and our share of third-party fees for liquids extraction through our Rogersville plant, which we continue to co-own with Seminole Energy.

Expenses. The following table shows the components of our direct and other expenses for the three months ended September 30, 2009 and 2008. Percentages listed in the table reflect margins for each component of direct expenses and percentages of total revenue for each component of other expenses.

	Three Months Ended September 30,			
	2009	Margin	2008	Margin
Direct Expenses:				
Contract drilling.....	\$ 2,913,418	24%	\$ 7,570,698	23%
Oil and gas production.....	2,658,985	57	3,922,629	65
Gas transmission, compression and processing	<u>960,879</u>	15	<u>1,039,597</u>	60
Total direct expenses.....	<u>6,533,282</u>	42	<u>12,532,924</u>	47
Other Expenses (Income):				
		% Revenue		% Revenue
Selling, general and administrative	2,601,514	23%	3,551,908	15%
Options, warrants and deferred compensation	285,309	3	229,209	1
Depreciation, depletion and amortization	3,304,139	30	3,318,320	14
Bad debt expense	—	N/A	342,195	1
Interest expense, net of interest income	1,138,711	10	1,446,526	6
Gain on sale of assets	(3,356,177)	N/A	—	N/A
Other, net	<u>292,073</u>	3	<u>87,584</u>	—
Total other expenses	<u>\$ 4,265,569</u>		<u>\$ 8,975,742</u>	

Contract drilling expenses reflect the level and timing of drilling initiatives conducted through our sponsored partnerships. These expenses represented 76% of contract drilling revenues in the current quarter, compared to 77% in the year-earlier period. Margins for contract drilling operations reflect our cost-plus pricing model, which we adopted in 2006 to address price volatility for drilling services, equipment and steel casing requirements.

Production expenses represent lifting costs, field operating and maintenance expenses, related overhead, severance and other production taxes, third-party transportation fees and processing costs. Historically, our ownership of the Gathering System eliminated transportation costs for our share of Leatherwood, Straight Creek, Fonde and Stone Mountain production delivered through the system. The increase in production expenses on a period-over-period basis primarily reflects higher transportation costs following our sale of the Gathering System, which will further impact these costs in future periods. See “Recent Developments.” As a percentage of revenues, overall production expenses in the current quarter benefitted from lower severance taxes and various cost-cutting measures for our field operations.

Our gas transmission and compression expenses, as well as capitalized costs for this part of our business, were substantially reduced in the third quarter of 2009 following our sale of the Gathering System. Our remaining infrastructure position is comprised of 100% interests in the gas gathering facilities for our Haley’s Mill and Kay Jay fields, 50% interests in our Haley’s Mill and Rogersville processing plants and a 25% interest in the gathering system for our non-operated Arkoma properties. Our gas transmission, compression and processing expenses in future periods will reflect this reduction in our infrastructure asset base.

Selling, general and administrative (*SG&A*) expenses are comprised primarily of selling and promotional costs for our sponsored drilling partnerships and general overhead costs. Our *SG&A* expenses in the current quarter decreased by 27% from the same period last year, primarily due to the timing of partnership sales, and represented 23% of revenues in the current quarter, compared to 15% in the third quarter of 2008.

Non-cash charges for options, warrants and deferred compensation reflect the fair value method of accounting for employee stock options. Under this method, employee stock options are valued at the grant date using the Black-Scholes valuation model, and the compensation cost is recognized ratably over the vesting period. We also recognized an accrual of \$153,637 for deferred compensation cost in the current quarter.

Depreciation, depletion and amortization (*DD&A*) is recognized under the units-of-production method, based on the estimated proved developed reserves of the underlying oil and gas properties, and on a straight-line basis over the useful life of other property and equipment. The decrease in *DD&A* charges reflects a reduction in historical depletion costs for our Gathering System following its sale, partially offset by additions to our oil and gas properties.

Interest expense for the 2009 third quarter decreased 18% from the year-earlier period, reflecting the reduction of debt levels under our revolving credit facility from proceeds of our Gathering System sale and equity raise. In addition to improving our liquidity, the reduction in our credit facility debt from these transactions will provide ongoing savings on future interest expense.

We recognized a pre-tax gain of \$3,356,367 during the third quarter of 2009 from the sale of our interests in the Gathering System. See “Recent Developments.” We acquired the open-access portion of the Gathering System from Duke Energy in March 2006 for \$18 million and built out the field-wide portions of the facilities at historical costs totaling approximately \$33.5 million.

Deferred income tax expense represents future tax liabilities at the operating company level. Although we have no current tax liability at that level due to the utilization of intangible drilling costs, our consolidated income tax expense is negatively impacted by the non-recognition of tax benefits at the parent company level.

Net Income (Loss) and EPS. We recognized a net loss of \$112,472 in the third quarter of 2009, reflecting the foregoing factors. Earnings (loss) per share (*EPS*) was \$(0.00) on 28,873,105 weighted average common shares outstanding. Before giving effect to the after-tax gain from our sale of the Gathering System, we had a net loss of \$2,126,292 or \$(0.07) per share in the third quarter of 2009, compared to net income of \$945,185 realized in the same quarter last year, with *EPS* of \$0.04 on 26,977,438 fully diluted shares.

Results of Operations – Nine Months Ended September 30, 2009 and 2008

Revenues. The following table shows the components of our revenues for the nine months ended September 30, 2009 and 2008, together with their percentages of total revenue in the current period and percentage change on a period-over-period basis.

Revenue:	Nine Months Ended September 30,			
	2009	% of Revenue	2008	% Change
Contract drilling.....	\$ 16,328,000	38%	\$ 24,027,035	(32)%
Oil and gas production.....	20,198,187	47	30,891,933	(35)
Gas transmission, compression and processing.....	<u>6,528,132</u>	<u>15</u>	<u>7,662,504</u>	(15)
Total.....	<u>\$ 43,054,319</u>	<u>100%</u>	<u>\$ 62,581,472</u>	(31)

Our contract drilling revenues in the first nine months of 2009 reflect the completion of drilling operations for our 2008 drilling partnership, which participated in 89 wells on non-operated properties in West Virginia and Virginia, as well as the commencement of operations for our 2009 drilling partnership, which participated in nine horizontal wells through the end of the third quarter.

Production revenues for the first nine months of 2009 reflect a 9% increase in production output to 3,037 Mmcfe, compared to 2,779 Mmcfe in the year-earlier period, offset by declines of 33% in natural gas prices, 55% in oil prices and 61% for NGL sales. Our volumetric growth, while negatively impacted by the reduction in drilling activity in the current period, reflects strong performance from horizontal drilling initiatives beginning in February 2008 and the commencement of production from our Haley's Mill field later in the year and non-operated wells in West Virginia. Approximately 50% of our natural gas production in the first nine months of 2009 was sold under fixed-price contracts, and the balance at index-based pricing. Realized natural gas prices in the current period averaged \$7.44 per Mcf for our Appalachian production and \$6.31 per Mcf overall, compared to an average overall realization of \$8.25 per Mcf in the first nine months of 2008.

Gas transmission, compression and processing revenues for the current period were driven by fees for moving our drilling program investors' share of gas through the Gathering System prior to its sale and processing fees for liquids extraction through our Rogersville plant. This component of revenues also includes contributions from gas utility sales.

Expenses. The following table shows the components of our direct and other expenses for the nine months ended September 30, 2009 and 2008. Percentages listed in the table reflect margins for each component of direct expenses and percentages of total revenue for each component of other expenses.

Direct Expenses:	Nine Months Ended September 30,			
	2009	Margin	2008	Margin
Contract drilling.....	\$ 12,328,110	24%	\$ 18,447,544	23%
Oil and gas production.....	7,598,044	62	9,794,679	68
Gas transmission, compression and processing.....	<u>2,955,204</u>	<u>55</u>	<u>3,087,391</u>	<u>60</u>
Total direct expenses.....	<u>22,881,358</u>	<u>47</u>	<u>31,329,614</u>	<u>50</u>
Other Expenses (Income):	% Revenue		% Revenue	
Selling, general and administrative.....	8,404,519	20%	10,282,485	16%
Options, warrants and deferred compensation.....	1,022,774	2	601,691	1
Depreciation, depletion and amortization.....	10,610,630	25	9,451,272	15
Bad debt expense.....	—	N/A	749,035	1
Interest expense, net of interest income.....	3,955,566	9	4,049,336	6
Gain on sale of assets.....	(3,369,082)	N/A	—	N/A
Other, net.....	<u>600,896</u>	<u>1</u>	<u>115,939</u>	<u>—</u>
Total other expenses.....	<u>\$ 21,225,303</u>		<u>\$ 25,249,758</u>	

Contract drilling expenses decreased by 33% on a period-over-period basis and represented 76% of contract drilling revenues in the first nine months of 2009, compared to 77% in the year-earlier period. Our contract drilling activities in the current period were limited to the completion of drilling on non-operated properties in West Virginia and Virginia for last year's drilling partnership and the commencement of operations for our 2009 drilling partnership in June 2009.

The decrease in production expenses on a period-over-period basis primarily reflects lower severance taxes and the adoption of various cost-cutting measures for our field operations. Our margins in both periods reflect cost savings realized from ownership of the Gathering System prior to its sale during the third quarter of 2009.

Gas transmission, compression and processing expenses in the first nine months of 2009 were 45% of associated revenues, compared to 40% in the same period last year. These expenses do not include capitalized costs of approximately \$1.5 million in the current period for extensions of our field-wide gas gathering systems and additions to dehydration and compression capacity required to bring new wells on line.

SG&A expenses in the current period decreased 18% from the same period last year. This primarily reflects the reduced level of drilling partnership sales, which are subject to considerable fluctuation and generally ramp up toward the end of the year. As a percentage of revenues, SG&A expenses increased to 20% in the first nine months of 2009, compared to 16% of revenues in the year-earlier period.

Non-cash charges for options, warrants and deferred compensation reflect the fair value method of accounting for employee stock options. Under this method, employee stock options are valued at the grant date using the Black-Scholes valuation model, and the compensation cost is recognized ratably over the vesting period. We also recognized an accrual of \$460,911 for deferred compensation cost in the current period.

The increase in DD&A for the current period reflects additions to our oil and gas properties, gas gathering systems and related equipment. We anticipate reductions in our DD&A rates of approximately 10% from historical levels as a result of our Gathering System sale in the third quarter of 2009.

We recognized a bad debt expense of \$347,840 in the first nine months of 2008. Coupled with prior-year reserves, this represented the entire amount due for oil sales to a regional refinery prior to its filing for reorganization under the bankruptcy laws in 2008. See “Critical Accounting Policies and Estimates – Allowance for Doubtful Accounts.”

We recorded a pre-tax gain of \$3,356,367 during the current period from the sale of our interests in the Gathering System. See “Recent Developments.” We estimate an after-tax gain of approximately \$2.0 million from the sale.

Interest expense for the first nine months of 2009 decreased 3% from the year-earlier period, reflecting lower rates under our revolving credit facility and a reduction of debt levels from our liquidity initiatives in the third quarter this year. See “Recent Developments – Liquidity from Gathering System Sale and Equity Raise.” Draws under the facility since the third quarter of 2008 were used primarily to support our ongoing drilling initiatives and enhancements of our field-wide gas gathering infrastructure.

Net Income (Loss) and EPS. We recognized a net loss of \$1,623,699 in the first nine months of 2009, reflecting the foregoing factors. EPS was \$(0.06) on 27,508,925 weighted average common shares outstanding. Before giving effect to the after-tax gain from our sale of the Gathering System, we had a net loss of \$3,637,519 or \$(0.13) per share in the first nine months of 2009, compared to net income of \$2,629,636 realized in the same period last year, with EPS of \$0.10 on 27,019,313 fully diluted shares.

The results of operations for the three months and nine months ended September 30, 2009 are not necessarily indicative of results to be expected for the full year.

Liquidity and Capital Resources

Liquidity. We completed a registered direct placement of 3.48 million units at \$1.90 per unit on August 13, 2009, with net proceeds of approximately \$6.1 million applied to debt reduction under our revolving credit facility. Each unit consists of one share of our common stock and a warrant to buy 0.5 common share. The warrants have a four-year term, beginning six months after issuance, and will be exercisable during that period for a total of 1.74 million shares of our common stock at \$2.35 per share, subject to adjustment for certain dilutive issuances.

During the first nine months of 2009, we generated net cash of \$3,688,054 from operating activities and \$25,324,894 from investing activities, which included proceeds from our Gathering System sale, all of which were applied to debt reduction under our revolving credit facility. Our investing activities also included capital expenditures aggregating \$6,089,476 for additions to oil and gas properties. As a result of these activities, our net cash of \$970,467 at the end of the current period was substantially the same as our net cash position at December 31, 2008.

We had working capital of \$4,991,050 as of September 30, 2009, compared to a working capital deficit of \$5,519,114 at December 31, 2008. This reflects the current portion of the note receivable from the sale of our Gathering System and wide fluctuations in our current assets and liabilities from the timing of customer deposits and expenditures under drilling contracts with our sponsored partnerships. We also have substantial changes our cash position from draws and payments under our credit facility. Since these fluctuations are normalized over relatively short time periods, we do not consider working capital to be a reliable measure of our liquidity.

Capital Resources. Our business involves significant capital requirements. The rate of production from oil and gas properties declines as reserves are depleted. Without successful development activities, our proved reserves would decline as oil and gas is produced from our proved developed reserves. We also have substantial annual drilling commitments under various leases and farmouts for our Appalachian properties, including an annual 25-well commitment for our Leatherwood field. Our long-term performance and profitability are dependent not only on meeting these commitments and recovering existing oil and gas reserves, but also on our ability to find or acquire additional reserves and fund their development on terms that are economically and operationally advantageous.

We have relied on a combination of cash flows from operations, bank borrowings and private placements of our convertible notes and equity securities to fund our reserve and infrastructure development and acquisition activities. Historically, we also relied on participation in our operated drilling initiatives by outside investors in our sponsored partnerships. For 2008, we changed our business model to accelerate organic growth by retaining all of our available working interest in wells drilled on operated properties, with a view to limiting our use of drilling partnerships to non-operated initiatives.

While we are committed to continue expanding our reserves and production through the drillbit, we have addressed the challenging conditions in our industry by reducing our 2009 capital spending budget to \$15 million, allocated primarily to drilling. This is in line with our anticipated cash flow from operations and reflects a 73% reduction from our 2008 capital expenditures. To meet our 2009 drilling commitments and objectives with this reduced capital spending budget, we have returned to our established partnership structure and sales network for a targeted raise of up to \$53.1 million from outside investors. We will contribute 20% of program capital and will have a proportionate interest in our 2009 program, which will increase to 35% after program payout. With our critical infrastructure in place, this will allow us to continue delivering organic growth, although at lower rates than we could otherwise achieve.

We have a senior secured revolving credit facility maintained by DPI under a credit agreement with KeyBank National Association, as administrative agent. The credit agreement provides for revolving term loans and letters of credit in an aggregate amount up to \$125 million, with a scheduled maturity in September 2011. Credit availability under the facility is subject to borrowing base limits, as determined semi-annually by the lenders. Outstanding borrowings bear interest at fluctuating rates ranging from the agent's prime rate to 2.25% above that rate, depending on the amount of borrowing base utilization. We are also responsible for commitment fees at rates ranging from 0.375% to 0.5% of the unused borrowing base. The facility is guaranteed by NGAS and is secured by liens on DPI's oil and gas properties.

As of September 30, 2009, we had outstanding borrowings of \$35 million under our credit facility, with a borrowing base of \$55 million. This reflects debt reductions totaling \$41.6 million from proceeds of our Gathering System sale and equity raise in the third quarter of 2009. At that time, our borrowing base was reduced by \$25 million to reflect lower commodity prices and the release of our Gathering System assets from the collateral package. A related amendment to the credit agreement provides for the further debt reduction from payments under a \$14.5 million promissory note issued to us by Seminole Energy as part of the purchase price for our Gathering System assets. The note is payable in monthly installments through December 2011, with interest at 8% per annum. See "Recent Developments."

We have an outstanding series of 6% convertible notes due December 15, 2010 in the aggregate principal amount of \$37 million. The notes are convertible into our common shares at a conversion price of \$11.16, reflecting an anti-dilution adjustment from our registered direct placement of common stock and warrants during the third quarter of 2009. In the event of a default under the notes or any change of control, the holders may require us to redeem the notes at a default rate equal to 125% of their principal amount or a change of control rate equal to the greater of 110% of their principal amount or the consideration that would be received by the holders for the underlying shares in the change of control transaction. Any notes that are neither redeemed nor converted prior to maturity will be repayable in cash or in common shares, valued for that purpose at 92.5% of their market price.

Our ability to repay our revolving credit and convertible debt will be subject to our future performance and prospects as well as market and general economic conditions. Our future revenues, profitability and rate of growth will continue to be substantially dependent on the demand and market price for natural gas. Future market prices for natural gas will also have a significant impact on our ability to maintain or increase our borrowing capacity, to obtain additional capital on acceptable terms and to attract drilling partnership capital. While we have been able to mitigate some of the steep decline in natural gas prices with fixed-price, fixed-volume physical delivery contracts that cover portions of our natural gas production, we are exposed to price volatility for future production not covered by these arrangements. See “Quantitative and Qualitative Disclosures about Market Risk.”

We have addressed the general economic downturn and current unsettled conditions in natural gas markets by monetizing our Gathering System, completing an equity raise, reducing our capital expenditure budget and returning to our established drilling partnership structure for participation in our development initiatives on operated properties. To realize our long-term goals for growth in revenues and reserves, however, we will need to retain more of our available working interest in future wells, requiring continued access to the credit and capital markets. Any prolonged constraints on our access to those markets on acceptable terms could require us to sell additional assets or pursue other financing or strategic arrangements to meet those objectives and to repay or refinance our long-term debt at maturity.

Forward Looking Statements

Some statements made by us in this report are prospective and constitute forward-looking statements within the meaning of Section 21E of the Securities Exchange Act and Section 27A of the Securities Act of 1933. Other than statements of historical fact, all statements that address future activities, outcomes and other matters we plan, expect, budget, intend or estimate, and other similar expressions, are forward-looking statements. These forward-looking statements involve known and unknown risks, uncertainties and other factors, many of which are beyond our control. Among other things, these include:

- uncertainty about estimates of future natural gas production and required capital expenditures;
- commodity price volatility;
- increases in the cost of developing and producing our reserves;
- unavailability of drilling rigs and services;
- drilling, operational and environmental risks;
- regulatory changes and litigation risks; and
- uncertainties in estimating oil and gas reserves and projecting future production rates.

If the assumptions we use in making forward-looking statements prove incorrect or the risks described in this report and incorporated by reference to our 2008 annual report were to occur, our actual results could differ materially from future results expressed or implied by the forward-looking statements in this report.

Contractual Obligations and Commercial Commitments

General. We are parties to leases for office facilities and various types of equipment. We are also obligated to make payments at specified times and amounts under instruments governing our long-term debt and other commercial commitments. The following table lists these minimum annual obligations as of September 30, 2009. The table does not include

Year	Operating Leases			Long Term Debt
	Equipment	Premises	Total	
Remainder of 2009	\$ 542,940	\$ 61,764	\$ 604,704	\$ 27,807
2010	2,102,680	247,815	2,350,495	36,663,866 ⁽¹⁾
2011	1,842,835	252,389	2,095,224	35,093,557
2012	591,469	255,973	847,442	2,157,461
2013 and thereafter	51,929	21,355	73,284	192,818
Total	<u>\$ 5,131,853</u>	<u>\$ 839,296</u>	<u>\$ 5,971,149</u>	<u>\$ 74,135,509</u>

(1) Excludes an allocation of \$425,731 from our 6% convertible notes in the principal amount of \$37,000,000 based on equity components of their conversion features.

Gas Gathering and Sales Commitments. We have various commitments under our gas gathering and sales agreements entered with Seminole and Seminole Energy in connection with our sale of the Gathering System during the third quarter of 2009. See “Recent Developments.” These agreements provide us with firm capacity rights for daily delivery of 30,000 Mcf of controlled gas and have an initial term of fifteen years with extension rights. Our commitments under these agreements include:

- Base monthly gathering fees of \$850,000, with annual escalations at the rate of 1.5%;
- Base monthly operating fees of \$175,000, plus \$0.20 per Mcf of purchased gas; and
- Monthly capital fees in amounts intended to yield a 20% internal rate of return for all capital expenditures on the Gathering System by Seminole and Seminole Energy.

Critical Accounting Policies and Estimates

General. The preparation of financial statements requires management to utilize estimates and make judgments that affect the reported amounts of assets, liabilities, revenues and expenses and related disclosure of contingent assets and liabilities. These estimates are based on historical experience and on various other assumptions that management believes to be reasonable under the circumstances. The estimates are evaluated by management on an ongoing basis, and the results of these evaluations form a basis for making decisions about the carrying value of assets and liabilities that are not readily apparent from other sources. Although actual results may differ from these estimates under different assumptions or conditions, management believes that the estimates used in the preparation of our financial statements are reasonable. The critical accounting policies affecting these aspects of our financial reporting are summarized in Note 1 to the consolidated financial statements included in our 2008 annual report. Policies involving the more significant judgments and estimates used in the preparation of our consolidated financial statements are summarized below.

Estimates of Proved Reserves and Future Net Cash Flows. Estimates of our proved oil and gas reserves and related future net cash flows are used in impairment tests of goodwill and other long-lived assets. These estimates are prepared as of year end by our independent petroleum engineers and are updated internally at mid-year. There are many uncertainties inherent in estimating quantities of proved reserves and in projecting future rates of production and timing of development expenditures. The accuracy of any reserve estimate is dependent on the quality of available data and is subject to engineering and geological interpretation and judgment. Results of our drilling, testing and production after the date of these estimates may require future revisions, and actual results could differ materially from the estimates.

Impairment of Long-Lived Assets. Our long-lived assets include property, equipment and goodwill. Long-lived assets with an indefinite life are reviewed at least annually for impairment, while other long-lived assets are reviewed whenever events or changes in circumstances indicate that carrying values of these assets are not recoverable.

Allowance for Doubtful Accounts. We maintain an allowance for doubtful accounts when deemed appropriate to reflect losses that could result from failures by customers or other parties to make payments on our trade receivables. The estimates of this allowance, when maintained, are based on a number of factors, including historical experience, aging of the trade accounts receivable, specific information obtained on the financial condition of customers and specific agreements or negotiated settlements with customers.

Item 3. Quantitative and Qualitative Disclosures about Market Risk

Commodity Price Risk

Our major market risk exposure is the pricing of natural gas production, which has been highly volatile and unpredictable during the last several years. While we do not use financial hedging instruments to manage our exposure to these fluctuations or for speculative trading purposes, we do use fixed-price, fixed-volume physical delivery contracts that cover portions of our natural gas production at specified prices during varying periods of time up to two years from the contract date. Because these physical delivery contracts qualify for the normal purchase and sale exception under SFAS No. 133, they are not treated as financial hedging activities and are not subject to mark-to-market accounting. The financial impact of physical delivery contracts is included in our oil and gas revenues at the time of settlement, which in turn affects our average realized natural gas prices.

Financial Market Risks

Interest Rate Risk. Borrowings under our secured credit facility bear interest at fluctuating market-based rates. Accordingly, our interest expenses are sensitive to market changes, which exposes us to interest rate risk on current and future borrowings under the facility.

Foreign Market Risk. We sell our products and services exclusively in the United States and receive payment solely in United States dollars. As a result, our financial results are unlikely to be affected by factors such as changes in foreign currency exchange rates or weak economic conditions in foreign markets, except to the extent they affect domestic natural gas markets.

Item 4. Controls and Procedures

Management's Responsibility for Financial Statements

Our management is responsible for the integrity and objectivity of all information presented in this report. The consolidated financial statements included in this report have been prepared in accordance with U.S. GAAP and reflect management's judgments and estimates on the effect of the reported events and transactions.

Disclosure Controls and Procedures

Our management, with the participation of our chief executive officer and chief financial officer, evaluated the effectiveness of our disclosure controls and procedures, as defined in Rule 13a-15(e) under the Exchange Act, as of the end of the period covered by this report. Based on management's evaluation as of September 30, 2009, our chief executive officer and chief financial officer have concluded that our disclosure controls and procedures are effective to ensure that material information about our business and operations is recorded, processed, summarized and publicly reported within the time periods required under the Exchange Act, and that this information is accumulated and communicated to our management to allow timely decisions about required disclosures.

Management's Report on Internal Control over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as defined in Rule 13a-15(f) under the Exchange Act. Management assessed the effectiveness of our internal control over financial reporting as of September 30, 2009 using the criteria established under *Internal Control – Integrated Framework*, issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on that assessment, management concluded that our internal control over financial reporting was effective based on those criteria as of September 30, 2009.

Changes in Internal Control over Financial Reporting

We regularly review our system of internal control over financial reporting to ensure the maintenance of an effective internal control environment. There were no changes in our internal control over financial reporting during the period covered by this report that have materially affected or are reasonably likely to materially affect our internal control over financial reporting.

PART II. OTHER INFORMATION

Item 6. Exhibits

Exhibit

Number Description of Exhibit

- | | |
|-----|--|
| 3.1 | Notice of Articles, certified on September 3, 2004 by the Registrar of Corporations under the British Columbia Business Corporations Act (incorporated by reference to Exhibit 3.1 to Current Report on Form 8-K [File No. 0-12185], filed September 29, 2004). |
| 3.2 | Alteration to Notice of Articles, certified on September 25, 2004 by the Registrar of Corporations under the British Columbia Business Corporations Act (incorporated by reference to Exhibit 3.2 to Current Report on Form 8-K [File No. 0-12185], filed September 29, 2004). |
| 3.3 | Articles dated September 25, 2004, as amended and restated for corporate transition under the British Columbia Business Corporations Act (incorporated by reference to Exhibit 3.3 to Current Report on Form 8-K [File No. 0-12185], filed September 29, 2004). |

- 10.1 1997 Stock Option Plan (incorporated by reference to Exhibit 10[a] to Annual Report on Form 10-KSB [File No. 0-12185] for the year ended December 31, 2002).
- 10.2 2001 Stock Option Plan (incorporated by reference to Exhibit 10[b] to Annual Report on Form 10-KSB [File No. 0-12185] for the year ended December 31, 2002).
- 10.3 2003 Incentive Stock and Stock Option Plan (incorporated by reference to Exhibit 10.3 to Quarterly Report on Form 10-QSB [File No. 0-12185] for the quarter ended September 30, 2004).
- 10.4 Form of 6% convertible notes issued pursuant to the Securities Purchase Agreement dated as of December 13, 2005 among NGAS Resources, Inc. and the investors named therein (incorporated by reference to Exhibit 10.2 to current report on Form 8-K [File No. 0-12185] dated December 14, 2005).
- 10.5 Amended and Restated Credit Agreement dated as of May 30, 2008 among NGAS Resources, Inc., Daugherty Petroleum, Inc. and KeyBank National Association, as agent for the lenders named therein (incorporated by reference to Exhibit 10.6 to Quarterly Report on Form 10-Q [File No. 0-12185] for the quarter ended June 30, 2008).
- 10.6 Third Amendment dated as of June 2, 2009 to Amended and Restated Credit Agreement dated as of May 30, 2008 among NGAS Resources, Inc., Daugherty Petroleum, Inc. and KeyBank National Association, as agent for the lenders named therein (incorporated by reference to Exhibit 10.1 to Current Report on Form 8-K [File No. 0-12185] filed June 5, 2009).
- 10.7 NAESB Gas Purchase Agreement dated as of July 15, 2009 between Daugherty Petroleum, Inc. and Seminole Energy Services, LLC (incorporated by reference to Exhibit 10.5 to current report on Form 8-K [File No. 0-12185] dated July 17, 2009).
- 10.8 Form of Change of Control Agreement dated as of February 25, 2004 (incorporated by reference to Exhibit 10.9 to quarterly report on Form 10-QSB [File No. 0-12185] for the quarter ended June 30, 2004).
- 10.9 Form of Indemnification Agreement dated as of February 25, 2004 (incorporated by reference to Exhibit 10.10 to quarterly report on Form 10-QSB [File No. 0-12185] for the quarter ended June 30, 2004).
- 10.10 Form of Long-Term Incentive Agreement dated as of February 25, 2004 (incorporated by reference to Exhibit 10.11 to quarterly report on Form 10-QSB [File No. 0-12185] for the quarter ended June 30, 2004).
- 10.11 Form of Long-Term Incentive Agreement dated as of December 9, 2008 (incorporated by reference to Exhibit 10.11 to annual report on Form 10-K [File No. 0-12185] for the year ended December 31, 2008).
- 10.12 Form of general partnership agreement with sponsored drilling programs (incorporated by reference to Exhibit 10.11 to amended annual report on Form 10-K/A [File No. 0-12185] for the year ended December 31, 2006).
- 10.13 Form of limited partnership agreement with sponsored investment partnerships (incorporated by reference to Exhibit 10.12 to amended annual report on Form 10-K/A [File No. 0-12185] for the year ended December 31, 2006).
- 10.14 Form of assignment of drilling rights with sponsored drilling programs (incorporated by reference to Exhibit 10.13 to amended annual report on Form 10-K/A [File No. 0-12185] for the year ended December 31, 2006).
- 10.15 Form of drilling and operating agreement with sponsored drilling programs (incorporated by reference to Exhibit 10.14 to amended annual report on Form 10-K/A [File No. 0-12185] for the year ended December 31, 2006).
- 11.1 Computation of Earnings Per Share (included in Note 10 to the accompanying consolidated financial statements)
- 21.0 Subsidiaries (incorporated by reference to Exhibit 21.1 to annual report on Form 10-K [File No. 0-12185] for the year ended December 31, 2006).
- 31.1 Certification of Chief Executive Officer pursuant to Exchange Act Rule 13a-14(a), as adopted under Section 302 of the Sarbanes-Oxley Act of 2002.
- 31.2 Certification of Chief Financial Officer pursuant to Exchange Act Rule 13a-14(a), as adopted under Section 302 of the Sarbanes-Oxley Act of 2002.

- 32.1 Certification of Chief Executive Officer pursuant to Exchange Act Rule 13a-14(b), as adopted under Section 906 of the Sarbanes-Oxley Act of 2002.
- 32.2 Certification of Chief Financial Officer pursuant to Exchange Act Rule 13a-14(b), as adopted under Section 906 of the Sarbanes-Oxley Act of 2002.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

NGAS RESOURCES, INC.

Date: November 3, 2009

By: /s/ WILLIAM S. DAUGHERTY
William S. Daugherty
Chief Executive Officer
(Duly Authorized Officer)
(Principal Executive Officer)

**CERTIFICATION OF CHIEF EXECUTIVE OFFICER
PURSUANT TO RULE 13A-14(A) OR 15D-14(A) UNDER THE SECURITIES EXCHANGE ACT OF 1934**

I, William S. Daugherty, certify that:

1. I have reviewed this quarterly report on Form 10-Q of NGAS Resources, Inc.;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
 - (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
 - (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
 - (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
 - (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing similar functions):
 - (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
 - (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

November 3, 2009

/s/ William S. Daugherty

William S. Daugherty
Chairman, Chief Executive Officer and President

**CERTIFICATION OF CHIEF FINANCIAL OFFICER
PURSUANT TO RULE 13A-14(A) OR 15D-14(A) UNDER THE SECURITIES EXCHANGE ACT OF 1934**

I, Michael P. Windisch, certify that:

1. I have reviewed this quarterly report on Form 10-Q of NGAS Resources, Inc.;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report.
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e))and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
 - (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
 - (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
 - (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
 - (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing similar functions):
 - (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
 - (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

November 3, 2009

/s/ Michael P. Windisch

Michael P. Windisch
Chief Financial Officer

CERTIFICATION PURSUANT TO RULE 13A-14(B) OR 15D-14(A) UNDER THE SECURITIES EXCHANGE ACT OF 1934
AND
SECTION 1350 OF CHAPTER 63 OF TITLE 18 OF THE UNITED STATES CODE

In connection with this quarterly report of NGAS Resources, Inc. on Form 10-Q for the quarter ended September 30, 2009, as filed with the Securities Exchange Commission on the date hereof (the "Report"), the undersigned hereby certify pursuant to 18 U.S.C. § 1350 that:

1. The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and
2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of NGAS Resources, Inc. as of the date and for the periods reported therein.

November 3, 2009

By: /s/ William S. Daugherty
William S. Daugherty
Chairman, Chief Executive Officer
and President

By: /s/ Michael P. Windisch
Michael P. Windisch
Chief Financial Officer