
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, 2008

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 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 3, 2008
26,543,646

NGAS RESOURCES, INC.

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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 headquarters are located in Lexington, Kentucky, and our common stock is traded on the Nasdaq Global Select Market under the symbol *NGAS*. Unless otherwise indicated, references in this report to *we*, *our* or *us* include NGAS Resources, Inc., our direct and indirect wholly owned subsidiaries and our interests in sponsored drilling programs. As used in this report, *Dth* means decatherm, *Mcf* means thousand cubic feet, *Bcf* means billion cubic feet, *Mcfe* means thousand cubic feet of gas equivalents and *Bcfe* means billion cubic feet of gas equivalents.

NGAS RESOURCES, INC.

CONDENSED CONSOLIDATED BALANCE SHEETS

ASSETS	<u>September 30, 2008</u>	<u>December 31, 2007</u>
Current assets:	(Unaudited)	
Cash	\$ 682,209	\$ 2,816,678
Accounts receivable.....	13,144,876	7,909,943
Prepaid expenses and other current assets	733,316	505,778
Loans to related parties.....	<u>7,445</u>	<u>7,654</u>
Total current assets	14,567,846	11,240,053
Bonds and deposits	666,195	535,445
Oil and gas properties	213,371,524	183,823,702
Property and equipment	3,464,974	3,689,636
Loans to related parties	245,081	249,410
Deferred financing costs	1,729,957	1,706,852
Other non-current assets.....	--	3,242,790
Goodwill	<u>313,177</u>	<u>313,177</u>
Total assets	<u>\$234,358,754</u>	<u>\$204,801,065</u>
LIABILITIES		
Current liabilities:		
Accounts payable	\$ 10,334,393	\$ 6,649,809
Accrued liabilities.....	4,125,283	3,655,684
Customer drilling deposits.....	--	2,857,806
Deferred compensation.....	2,229,086	--
Long term debt, current portion.....	<u>24,000</u>	<u>388,856</u>
Total current liabilities	16,712,762	13,552,155
Deferred income taxes	12,591,234	9,218,770
Long term debt.....	100,998,235	80,160,915
Deferred compensation	<u>--</u>	<u>1,960,020</u>
Total liabilities.....	<u>130,302,231</u>	<u>104,891,860</u>
SHAREHOLDERS' EQUITY		
Capital stock		
<i>Authorized:</i>		
5,000,000 Preferred shares		
100,000,000 Common shares		
<i>Issued:</i>		
26,543,646 Common shares (2007 – 26,136,064)	110,626,912	108,842,526
21,100 Common shares held in treasury, at cost.....	(23,630)	(23,630)
Paid-in capital – options and warrants	3,482,083	3,484,148
<i>Contributed surplus</i>	778,583	1,043,222
<i>To be issued:</i>		
9,185 Common shares.....	<u>45,925</u>	<u>45,925</u>
	114,909,873	113,392,191
Deficit	<u>(10,853,350)</u>	<u>(13,482,986)</u>
Total shareholders' equity	<u>104,056,523</u>	<u>99,909,205</u>
Total liabilities and shareholders' equity	<u>\$234,358,754</u>	<u>\$204,801,065</u>

See accompanying notes.

NGAS RESOURCES, INC.

CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS

(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2008	2007	2008	2007
REVENUE				
Contract drilling.....	\$ 9,799,561	\$ 6,730,929	\$ 24,027,035	\$ 23,435,852
Oil and gas production	11,222,879	6,690,916	30,891,933	20,174,095
Gas transmission, compression and processing.....	2,567,852	1,793,970	7,662,504	5,628,950
Total revenue	23,590,292	15,215,815	62,581,472	49,238,897
DIRECT EXPENSES				
Contract drilling	7,570,698	5,291,342	18,447,544	18,391,079
Oil and gas production	3,922,629	1,873,413	9,794,679	5,355,613
Gas transmission, compression and processing.....	1,039,597	783,970	3,087,391	2,663,406
Impairment of oil and gas assets	--	--	--	964,000
Total direct expenses	12,532,924	7,948,725	31,329,614	27,374,098
OTHER EXPENSES (INCOME)				
Selling, general and administrative	3,551,908	2,572,348	10,282,485	9,636,594
Options, warrants and deferred compensation ..	229,209	261,327	601,691	931,627
Depreciation, depletion and amortization	3,318,320	2,493,219	9,451,272	7,160,865
Bad debt expense	342,195	215,000	749,035	215,000
Interest expense.....	1,457,300	1,834,852	4,138,913	4,593,824
Interest income.....	(10,774)	(81,063)	(89,577)	(214,806)
Other, net.....	87,584	(96,385)	115,939	41,520
Total other expenses	8,975,742	7,199,298	25,249,758	22,364,624
INCOME (LOSS) BEFORE INCOME TAXES	2,081,626	67,792	6,002,100	(499,825)
INCOME TAX EXPENSE.....	1,136,441	126,356	3,372,464	573,427
NET INCOME (LOSS)	\$ 945,185	\$ (58,564)	\$ 2,629,636	\$ (1,073,252)
NET INCOME (LOSS) PER SHARE				
Basic	\$ 0.04	\$ 0.00	\$ 0.10	\$ (0.05)
Diluted	\$ 0.04	\$ 0.00	\$ 0.10	\$ (0.05)
WEIGHTED AVERAGE COMMON SHARES OUTSTANDING:				
Basic.....	26,508,570	21,804,959	26,364,158	21,798,275
Diluted	26,977,438	21,804,959	27,019,313	21,798,275

See accompanying notes.

NGAS RESOURCES, INC.

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2008	2007	2008	2007
OPERATING ACTIVITIES				
Net income (loss)	\$ 945,185	\$ (58,564)	\$ 2,629,636	\$ (1,073,252)
Adjustments to reconcile net income to net cash used in operating activities:				
Incentive bonus paid in common shares	228,120	--	259,690	3,010
Compensation from options and warrants	229,209	261,327	601,691	931,627
Depreciation, depletion and amortization	3,318,320	2,493,219	9,451,272	7,160,865
Bad debt expense	342,195	215,000	749,035	215,000
Impairment of oil and gas assets	--	--	--	964,000
Gain (loss) on sale of assets	(10,761)	(28,834)	(11,116)	49,307
Deferred income taxes	1,136,441	126,356	3,372,464	573,427
Changes in assets and liabilities				
Accounts receivable	(1,840,648)	800,805	(5,983,968)	1,944,462
Prepaid expenses and other current assets ..	(345,152)	65,317	(227,538)	307,937
Other non-current assets	--	116,221	3,242,790	(751,737)
Accounts payable	2,979,900	808,096	3,684,584	(1,819,754)
Accrued liabilities	261,981	(59,711)	469,599	(538,872)
Customers' drilling deposits	<u>(1,630,304)</u>	<u>(4,380,328)</u>	<u>(2,857,806)</u>	<u>(11,686,100)</u>
Net cash provided by (used in) operating activities	<u>5,614,486</u>	<u>358,904</u>	<u>15,380,333</u>	<u>(3,720,080)</u>
INVESTING ACTIVITIES				
Proceeds from sale of assets	15,855	355,000	54,555	389,700
Purchase of property and equipment	(155,170)	(340,590)	(459,671)	(1,327,094)
Change in bonds and deposits	(95,250)	105,500	(130,750)	68,500
Additions to oil and gas properties, net	<u>(11,615,165)</u>	<u>(13,187,693)</u>	<u>(37,940,322)</u>	<u>(38,711,872)</u>
Net cash used in investing activities	<u>(11,849,730)</u>	<u>(13,067,783)</u>	<u>(38,476,188)</u>	<u>(39,580,766)</u>
FINANCING ACTIVITIES				
Decrease in loans to related parties	1,861	1,889	4,538	5,599
Proceeds from issuance of common shares	81,200	151,250	1,190,006	191,550
Payments of deferred financing costs	(297,440)	--	(440,983)	--
Proceeds from issuance of long term debt	5,500,000	15,100,000	22,240,000	34,100,000
Payments of long term debt	<u>(6,000)</u>	<u>(6,000)</u>	<u>(2,032,175)</u>	<u>(18,000)</u>
Net cash provided by financing activities	<u>5,279,621</u>	<u>15,247,139</u>	<u>20,961,386</u>	<u>34,279,149</u>
Change in cash	(955,623)	2,538,260	(2,134,469)	(9,021,697)
Cash, beginning of period	<u>1,637,832</u>	<u>2,872,020</u>	<u>2,816,678</u>	<u>14,431,977</u>
Cash, end of period	<u>\$ 682,209</u>	<u>\$ 5,410,280</u>	<u>\$ 682,209</u>	<u>\$ 5,410,280</u>
SUPPLEMENTAL DISCLOSURE				
Interest paid	\$ 1,456,786	\$ 1,754,715	\$ 4,138,104	\$ 4,512,167
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 of America (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, 2007. 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 38 drilling programs sponsored to participate in some of its 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 programs. 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, 2008 and results of operations and cash flows for the three months and nine months ended September 30, 2008 and 2007.

(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 deemed appropriate to reflect losses that could result from failures by customers or other parties to make payments on our trade receivables. The evaluations required for all of these estimates involve significant uncertainties, and actual results could differ from the estimates.

Note 2. Oil and Gas Properties

(a) 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, 2008 and December 31, 2007 are summarized below.

	September 30, 2008	December 31, 2007
Proved oil and gas properties.....	\$176,990,690	\$148,981,923
Unproved oil and gas properties	4,765,413	3,876,721
Gathering facilities and well equipment	<u>64,413,858</u>	<u>55,370,995</u>
	246,169,961	208,229,639
Accumulated DD&A	<u>(32,798,437)</u>	<u>(24,405,937)</u>
Net oil and gas properties and equipment	<u>\$213,371,524</u>	<u>\$183,823,702</u>

(b) Suspended Well Costs. We adopted FSP No. 19-1, *Accounting for Suspended Well Costs*, effective January 1, 2005. Based on our evaluation at the time of adoption, we had found proved reserves for all our

exploratory wells within one year after completion of drilling. We added suspended well costs late in 2005 and during 2006 for an exploratory program to test the New Albany shale formation on the eastern rim of the Illinois Basin in western Kentucky. Based on the criteria of FSP No. 19-1, we expensed suspended well costs of \$178,700 for the first three wells in that program during 2006 and \$964,000 for the remaining 27 wells in the program during the second quarter of 2007. As of September 30, 2008, we had no wells for which exploratory wells costs had been capitalized for a period of greater than one year after completion of drilling.

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, 2008 and December 31, 2007.

	September 30, 2008	December 31, 2007
Land.....	\$ 12,908	\$ 12,908
Building improvements	62,365	58,051
Machinery and equipment	3,304,744	3,170,601
Office furniture and fixtures	175,862	168,217
Computer and office equipment	656,828	578,317
Vehicles.....	<u>1,989,666</u>	<u>1,869,551</u>
	6,202,373	5,857,645
Accumulated depreciation	<u>(2,737,399)</u>	<u>(2,168,009)</u>
Net other property and equipment.....	<u>\$ 3,464,974</u>	<u>\$ 3,689,636</u>

Note 4. Deferred Financing Costs

Financing costs for our convertible notes and secured credit facility are initially capitalized and amortized at rates based on the terms of the underlying debt instruments. See Note 7 – 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 \$1,729,957 at September 30, 2008 and \$1,706,852 at December 31, 2007, net of accumulated amortization totaling \$1,897,372 and \$1,479,494, respectively.

Note 5. 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, 2008 and December 31, 2007, with unamortized goodwill of \$313,177.

Note 6. Customer Drilling Deposits

Net proceeds received under drilling contracts with sponsored programs 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 \$2,857,806 at December 31, 2007, representing unapplied drilling contract payments for wells that were not yet drilled as of the balance sheet date, with no unapplied drilling contract payments at September 30, 2008.

Note 7. 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 \$12.94, reflecting an antidilution adjustment from the issuance of 4.2 million shares of our common stock in November 2007, based on our net proceeds of approximately \$23.7 million. See Note 8 – Capital Stock. We will be entitled to redeem the notes at 100% of their principal amount plus accrued and unpaid interest if the prevailing market price of our common stock exceeds 160% of the note conversion price for specified periods. Upon any event

of default under the notes or any change of control, we may be required to redeem the notes at a default rate equal to 125% of their principal amount or at 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 prevailing market price.

(b) *Credit Facility.* We have a senior secured revolving credit facility maintained by DPI with KeyBank National Association, as agent and primary lender. The facility provides for revolving term loans and letters of credit in an aggregate amount up to \$125 million. Outstanding borrowings under the facility bear interest at fluctuating rates ranging from the agent's prime rate to 1.0% above that rate, depending on the amount of borrowing base utilization. Alternatively, we may elect Eurodollar based pricing from 1.5% to 3.0% above quoted LIBOR rates. We are also responsible for commitment fees at rates ranging from 0.375% to 0.5% of the unused borrowing base. In May 2008, we amended the facility to add to the collateral package and increase the borrowing base from \$65 million to \$75 million, which was increased to \$90 million in August 2008. As of September 30, 2008, outstanding borrowings under the facility aggregated \$64.5 million, with \$2 million in letters of credit. The facility is secured by liens on our proved oil and gas properties and open-access gathering facilities. Obligations under the facility have a scheduled maturity in September 2011 and are guaranteed by NGAS.

(c) *Equipment Loan.* We obtained a term loan of \$2.1 million in September 2007 from Central Bank & Trust Co. to finance two previously purchased drilling rigs that we leased to one of our drilling contractors. The loan was repayable in monthly installments over a five-year term, bearing interest at 8% per annum, and was prepaid without penalty during the first quarter of 2008.

(d) *Acquisition Debt.* We issued a note for \$854,818 to finance our 1986 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, buildings and equipment. Although the acquisition agreement provides for royalties at 4% of production revenues, the property has remained inactive. The outstanding acquisition debt was \$300,818 at September 30, 2008.

(e) *Total Long Term Debt and Maturities.* The following tables summarize our total long term debt at September 30, 2008 and December 31, 2007 and the principal payments due each year through 2012 and thereafter.

	<u>Principal Amount Outstanding</u>	
	<u>September 30,</u> <u>2008</u>	<u>December 31,</u> <u>2007</u>
Total long term debt (including current portion) ⁽¹⁾	\$ 101,022,235	\$ 80,549,771
Less current portion	<u>24,000</u>	<u>388,856</u>
Total long term debt ⁽¹⁾	<u>\$ 100,998,235</u>	<u>\$ 80,160,915</u>

Maturities of Debt

Remainder of 2008	\$ 6,000
2009	24,000
2010	36,245,417 ⁽¹⁾
2011	64,524,000
2012 and thereafter	222,818

(1) Excludes allocations of \$778,583 at September 30, 2008 and \$1,043,222 at December 31, 2007 from our 6% convertible notes in the principal amount of \$37,000,000 based on equity components of their conversion features and related warrants, which expired unexercised in 2006.

Note 8. Capital Stock

(a) *Preferred Shares.* We have 5,000,000 authorized shares of preferred stock, none of which were outstanding at September 30, 2008 or December 31, 2007.

(b) *Common Shares.* We have 100,000,000 authorized shares of common stock. The following table reflects transactions in our common stock during the reported periods, including a direct placement of 4.2 million

common shares at \$6.00 per share completed in November 2007 under our existing shelf registration statement.

<u>Common Shares Issued</u>	<u>Number of Shares</u>	<u>Amount</u>
Balance, December 31, 2006	21,788,551	\$ 84,531,832
Issued in registered direct placement.....	4,200,000	23,687,955
Issued as stock awards under incentive plan.....	10,430	61,010
Issued upon exercise of stock options and warrants	<u>137,083</u>	<u>561,729</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, September 30, 2008.....	<u>26,543,646</u>	<u>\$110,626,912</u>
<u>Paid In Capital – Options and Warrants</u>		
Balance, December 31, 2006		\$ 3,073,287
Recognized		529,062
Exercised		<u>(118,201)</u>
Balance, December 31, 2007		3,484,148
Recognized		332,625
Exercised		<u>(334,690)</u>
Balance, September 30, 2008.....		<u>\$ 3,482,083</u>
<u>Contributed Surplus</u>		
Balance, December 31, 2006		\$ 1,396,074
Accreted ⁽¹⁾		<u>(352,852)</u>
Balance, December 31, 2007		1,043,222
Accreted ⁽¹⁾		<u>(264,639)</u>
Balance, September 30, 2008.....		<u>\$ 778,583</u>
<u>Common Shares to be Issued</u>		
Balance, September 30, 2008 and December 31, 2007.....	<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 stock plans for the benefit of our directors, officers, employees and certain consultants or advisors. The plans provide for the grant of options to purchase up to 3,600,000 common shares and, in the case of our most recent plan, either stock awards or options for an aggregate of up to 4,000,000 common shares. Option grants under all the plans must be at prevailing market prices and may be subject to vesting requirements over a period of up to ten years from the date of grant. Stock awards were made under the third plan for 10,430 shares during 2007 and 50,000 shares during the first nine months of 2008, along with stock option grants for 650,000 shares at exercise prices ranging from \$6.51 to \$7.64 per share during the interim period. The following table shows transactions in stock options under the plans during the reported periods.

<u>Stock Options</u>	<u>Issued</u>	<u>Exercisable</u>	<u>Weighted Average Exercise Price</u>
Balance, December 31, 2006	2,815,000	945,833	\$ 4.68
Vested	--	920,833	6.03
Exercised	(127,083)	(127,083)	3.17
Forfeited	<u>(6,667)</u>	<u>--</u>	6.02
Balance, December 31, 2007	2,681,250	1,739,583	4.75
Granted	650,000	--	6.53
Vested	--	41,667	6.02
Exercised	(357,582)	(357,582)	3.33
Forfeited	<u>(10,000)</u>	<u>(10,000)</u>	7.04
Balance, September 30, 2008.....	<u>2,963,668</u>	<u>1,413,668</u>	5.28

At September 30, 2008, the exercise prices of options outstanding under our equity plans ranged from \$4.03 to \$7.64 per share, and their weighted average remaining contractual life was 1.81 years. The following table provides additional information on the terms of stock options outstanding at September 30, 2008.

Options Outstanding					Options Exercisable	
Exercise Price or Range		Number	Weighted Average Remaining Life (years)	Weighted Average Exercise Price	Number	Weighted Average Exercise Price
\$ 4.03	4.09	1,540,000	1.07	\$ 4.05	740,000	\$ 4.06
6.02	7.64	<u>1,423,668</u>	2.61	6.66	<u>673,668</u>	6.88
		<u>2,963,668</u>			<u>1,413,668</u>	

In accounting for stock options, we apply the fair value recognition provisions of SFAS No. 123(R), *Share-Based Payment*, which we adopted retroactively in 2004. 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 4.5% to 6%, no dividend yield, a theoretical volatility ranging from 0.30 to 0.85 and an expected life ranging from six months to five years based on the option's vesting provisions. This resulted in non-cash charges for options and warrants of \$529,062 in 2007 and \$332,625 in the first nine months of 2008.

(d) *Common Stock Purchase Warrants.* We have issued common stock purchase warrants in various financing transactions. We had warrants for the purchase of 10,000 common shares at \$4.03 per share outstanding at December 31, 2006, which were fully exercised in the first quarter of 2007.

Note 9. Income (Loss) Per Share

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

Numerator:	Three Months Ended September 30,		Nine Months Ended September 30,	
	2008	2007	2008	2007
Net income (loss) as reported for basic EPS.....	\$ 945,185	\$ (58,564)	\$ 2,629,636	\$ (1,073,252)
Adjustments to income for diluted EPS.....	--	--	--	--
Net income (loss) for diluted EPS.....	<u>\$ 945,185</u>	<u>\$ (58,564)</u>	<u>\$ 2,629,636</u>	<u>\$ (1,073,252)</u>
Denominator:				
Weighted average shares for basic EPS.....	26,508,570	21,804,959	26,364,158	21,798,275
Effect of dilutive securities – stock options.....	468,868	--	655,155	--
Adjusted weighted average shares and assumed conversions for diluted EPS	<u>26,977,438</u>	<u>21,804,959</u>	<u>27,019,313</u>	<u>21,798,275</u>
Basic EPS.....	<u>\$ 0.04</u>	<u>\$ 0.00</u>	<u>\$ 0.10</u>	<u>\$ (0.05)</u>
Diluted EPS	<u>\$ 0.04</u>	<u>\$ 0.00</u>	<u>\$ 0.10</u>	<u>\$ (0.05)</u>

Note 10. 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 11. Commitments

We incurred operating lease expenses of \$2,317,526 in 2007 and \$1,933,498 in the first nine months of 2008. As of September 30, 2008, we had future obligations under operating leases and other commercial commitments in the amounts listed below.

<u>Year</u>	<u>Operating Leases</u>	<u>Other Commitments⁽¹⁾</u>	<u>Total</u>
Remainder of 2008.....	\$ 562,189	\$ --	\$ 562,189
2009	2,250,846	2,045,000	4,295,846
2010	2,182,717	--	2,182,717
2011	1,976,039	--	1,976,039
2012 and thereafter.....	920,725	--	920,725
Total	<u>\$ 7,892,516</u>	<u>\$ 2,045,000</u>	<u>\$ 9,937,516</u>

(1) Reflects commitments under a purchase contract for an airplane.

Note 12. Recent Accounting Standards

Oil and Gas Reporting Requirements. In June 2008, the SEC issued proposed amendments to its oil and gas reporting requirements 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 SEC has requested comments on various aspects of the proposals, which are expected to be included in final amendments that will be effective for fiscal years ending on or after December 31, 2009. We are assessing the proposal and will evaluate its impact on our reserve reporting when final regulations are issued.

SFAS No. 162. In May 2008, the FASB issued SFAS No. 162, *The Hierarchy of Generally Accepted Accounting Principles*. SFAS 162 identifies the sources of accounting principles and the framework for selecting principles to be used in the preparation and presentation of financial statements in accordance with U.S. GAAP. The statement will be effective 60 days after the SEC approves the Public Company Accounting Oversight Board's amendments to AU Section 411, *The Meaning of Present Fairly in Conformity With Generally Accepted Accounting Principles*. We do not expect the adoption of SFAS 162 to have an effect on our consolidated financial statements.

SFAS No. 161. In March 2008, the FASB issued SFAS No. 161, *Disclosures About Derivative Instruments and Hedging Activities*, which expands the quarterly disclosure requirements in SFAS No. 133 for derivative instruments and hedging activities, effective for fiscal years beginning after November 15, 2008. We do expect SFAS No. 161 to affect our consolidated financial position and results of operations.

FSP No. 157-2. In February 2008, the FASB issued FSP No. 157-2, *Effective Date of FASB Statement No. 157*, which defers the effective date of SFAS 157 for certain nonfinancial assets and nonfinancial liabilities, except those recognized or disclosed at fair value in the financial statements on a recurring basis. The deferred provisions of SFAS 157 affect assets measured at fair value in goodwill impairment testing, nonfinancial long-lived assets measured at fair value for impairment assessment and asset retirement obligations initially measured at fair value. We will adopt these deferred provision on January 1, 2009 and do not expect them to have a material impact on our consolidated financial position or results of operations.

SFAS No. 160. In December 2007, the FASB issued SFAS No. 160, *Noncontrolling Interests in Consolidated Financial Statements*, which establishes accounting and reporting standards for noncontrolling or minority interests in a subsidiary, including changes in a parent's ownership interest in a subsidiary. Under the new standard, noncontrolling interests in subsidiaries must be classified as a separate component of equity, and net income for both the parent and the noncontrolling interest must be disclosed on the consolidated statement of operations. SFAS No. 160 is effective for fiscal years and interim periods beginning after December 15, 2008, and its disclosure requirements will then apply retrospectively for all prior periods presented. We are assessing the affect its adoption may have on our consolidated financial statements.

SFAS No. 141(R). In December 2007, the FASB issued SFAS No. 141(R), *Business Combinations*. This statement provides revised guidance for recognizing and measuring assets acquired and liabilities assumed in a business combination. It also requires transactions costs for a business combination to be expensed as incurred. SFAS No. 141(R) will impact our accounting for any business acquisition we complete after 2008.

EITF 07-1. In December 2007, the FASB ratified the consensus reached by the Emerging Issues Task Force (EITF) in EITF Issue No. 07-1, *Accounting for Collaborative Arrangements*. The consensus requires costs incurred and revenues generated from transactions with third parties in collaborative arrangements to be reported on separate line items in the income statement pursuant to EITF Issue No. 99-19, *Reporting Revenue Gross as a Principal Versus Net as an Agent*. The consensus also provides that income statement characterization of payments between the participants in a collaborative arrangement should be based on existing authoritative pronouncements or a reasonable, rational and consistently applied accounting policy election. EITF Issue No. 07-1 is effective for fiscal years beginning after December 15, 2008 and must be applied retrospectively for collaborative arrangements existing on the date of adoption. We are currently evaluating the affect of this consensus but do not anticipate any material impact on our consolidated results of operations or financial condition.

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. We also control the gas gathering facilities for our core Appalachian properties, which spanned a total of 647 miles as of September 30, 2008, providing deliverability directly from the wellhead to interstate pipelines serving major east coast natural gas markets. We believe our extensive experience in this region, coupled with our midstream assets, gas gathering infrastructure and relationships with partners, suppliers and mineral interest owners, gives us competitive advantages in developing these resources to achieve annual volumetric growth and strong financial returns on a long term basis.

Strategy

Our business is structured to achieve capital appreciation through growth in our natural gas production and reserves. During the third quarter of 2008, our production increased to 948 Mmcfe, up 14% from the third quarter of 2007, despite a temporary curtailment of production from our non-operated interests in the Arkoma Basin. We began 2008 with estimated proved reserves of 105.2 Bcfe, of which 46% were proved developed. Our undeveloped acreage position provides us with a multi-year inventory of drilling locations for future growth, which may be accelerated by dynamic horizontal shale plays in our operating areas. Our strategy for continuing to capitalize on these opportunities under currently unsettled market conditions has several components.

- *Growth through the Drillbit with Reduced Capital Spending.* Development drilling is our mainstay for production and reserve growth. During the first nine months of 2008, we drilled 64 gross (58.9 net) wells on our operated properties in the Appalachian and Illinois Basins, along with 90 gross (12.9 net) non-operated wells. In the same period last year, we drilled 96 gross (47.4 net) operated wells and 73 gross (12.9 net) non-operated wells. This reflects the evolution of our business model for accelerating organic growth by retaining all of our available working interest in wells drilled on our core operated properties. We implemented this strategy late in 2007, resulting in an average working interest of 92% in wells drilled on operated properties during the first nine months of 2008, compared to 56% during the prior year. While we are committed to continue expanding our reserves and production through the drillbit, we are addressing current conditions in the financial and energy markets with a planned reduction in capital spending to approximately \$32.5 million for 2009. This is in line with our anticipated cash flow from operations and available funding under our revolving credit facility.
- *Horizontal Drilling Initiatives.* Horizontal drilling is enhancing the value proposition for many of our properties by substantially increasing our recovery volumes and rates at lower finding costs. Thus far, we have focused these initiatives in our Leatherwood field, where we have completed ten horizontal wells through the end of the third quarter. Each well has a single lateral leg up to 3,500 feet through the lower Huron section of the Devonian shale, which is present throughout most of our operating areas. For the initial month in production, we had average daily flow rates of 313 Mcf from nine completed wells in Leatherwood. During the third quarter, we expanded this program with our first horizontal New Albany shale well in our Haley's Mill field, with very encouraging initial results. Based on our current capital spending plan, we expect to drill a total of 22 horizontal wells by year end and up to 34 horizontal wells in 2009.
- *Control of Field-Wide Infrastructure.* We construct and operate field-wide gas gathering facilities to provide compression, connection and local distribution capabilities for most of our Appalachian production. Because we control third-party access to these facilities, they provide us with competitive advantages in acquiring and developing nearby acreage. We continually upgrade this infrastructure to keep pace with our expanding production base. Recent additions include 54 miles of gathering lines installed during the first nine months of 2008, including infrastructure for producing our New Albany shale project in western Kentucky, which we brought on line in late August 2008. We also completed

facilities to provide deliverability from our Fonde field through a 14-mile, six-inch steel line to our midstream system. Historically, production in Fonde had been limited by pipeline capacity constraints. Completion of our new facilities has enabled us to connect a backlog of wells drilled in Fonde over the last several years and open nearly 50,000 acres for future development in this field.

- Reduced Production Costs from Ownership of Midstream Assets. We own and operate a strategically located open-access gas gathering system spanning 116 miles in southeastern Kentucky and southwestern Virginia. We acquired this midstream system in 2006 through our NGAS Gathering subsidiary and augmented the system through two high-pressure lateral upgrades for connections to our field-wide gathering facilities, plus a recently completed processing plant for liquids extraction. We currently deliver all our production from the Leatherwood, Straight Creek, Fonde and SME fields to the interstate pipeline network through the NGAS Gathering system. As of September 30, 2008, the system had daily gross throughput of over 19,000 Dth, including third-party deliveries. In addition to generating gas transmission and processing revenues from third-party throughput and cost savings for our own Appalachian production, ownership of these midstream assets gives us control over gas flow from our connected fields and enhances our competitive position in the region.
- Development of Additional Drilling Prospects. We follow a disciplined capital allocation process in selecting opportunities to expand our substantial inventory of drilling prospects that meet our criteria for predictable, long-lived reserves. Our goal is to consolidate our position in the Appalachian Basin, while diversifying our asset base with similar unconventional plays outside the basin. As part of this strategy, we are aggressively developing our New Albany shale play in the Haley's Mill field, located within the southcentral portion of the Illinois Basin in western Kentucky. Through the date of this report, we have drilled a total of 37 wells in Haley's Mill. We completed our gas gathering system for Haley's Mill and began producing the field to sales in late August 2008, with flow rates of over 1,250 Mcf per day from 28 wells on line as of the date of this report. Based on these encouraging results, we have also launched a project to test the New Albany shale on recently acquired acreage outside Haley's Mill. If market conditions improve, we will continue developing these prospects.
- Purchase of Producing Properties. The purchase of third-party production offers a means in addition to drilling for capitalizing on our operating experience and accelerating our growth. Our acquisition criteria for producing properties include reserve life, profit enhancement potential, geographic concentration and operating rights. Based on those criteria, we launched a project in June 2008 to purchase the interests of outside investors in several of our mature drilling programs on an all-cash basis that gives effect to our reversionary interests in the programs. Through the date of this report, we have purchased 162 Mmcf of reserves from outside investors for a total purchase price of \$280,279. Based on the limited acceptance of our purchase offers, we do not plan to continue this project unless market conditions improve substantially.

Drilling Operations

General. As of September 30, 2008, we had interests in a total of 1,385 wells, concentrated on Appalachian properties that we operate and control through our gas gathering infrastructure. We believe our long and successful operating history in the southern portion of the Appalachian Basin and proven ability to drill a large number of wells year after year have positioned us as a leading player in this region. Historically, we conducted most of our drilling operations through sponsored drilling programs. Our combined interest as both general partner and an investor in these programs ranges from 12.5% to 75%, with additional reversionary interests after distribution thresholds are reached. Beginning in the second half of 2007, we changed our business model by limiting our use of drilling programs to participation in our non-operated initiatives, retaining all of our available working interest in wells drilled on operated properties.

Geological Factors. Most of our Appalachian wells are drilled to relatively shallow total depths up to 5,000 feet, generally encountering several predictable natural gas pay zones. The primary pay zone throughout this region 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. Typically, vertical gas wells in this part of Appalachia recover between 100 to 450 Mmcf of reserves, with modest initial volumes offset by low annual decline rates, resulting in a reserve life index of over 25 years. Based on our success to date with horizontal drilling and staged completions in these reservoirs, we anticipate substantial performance upside from our ongoing transition from vertical or horizontal drilling. The transition to horizontal drilling on our Appalachian properties also enhances our access to areas where natural gas development would otherwise be delayed or constrained by coal mining

activity.

Drilling Results. The following table shows the number of gross and net development and exploratory wells we drilled during 2007 and the first nine months of 2008. Drilling results shown in the table for 2007 include 89 gross (39.54 net) wells that were drilled by year end but were awaiting installation of gathering lines or extensions prior to completion. Gross wells are the total number of wells in which we have a working interest. Net wells reflect our working interests in wells, without giving effect to any reversionary interest we may subsequently earn in wells drilled through our drilling programs.

	Development Wells			Exploratory Wells		
	Productive		Dry	Productive		Dry
	Gross	Net	Gross	Gross	Net	Gross
Year ended December 31, 2007.....	211	76.1508	--	6	6.0000	--
Nine months ended						
September 30, 2008.....	145	63.0140	--	9	8.8125	--

The exploratory wells shown in the table for 2007 are part of a project to test the New Albany shale in the southcentral portion of the Illinois Basin on our Haley's Mill acreage. The exploratory wells listed for the interim period in 2008 include the initial three wells in a project to test the New Albany shale on recently acquired acreage outside our Haley's Mill field. The remaining six exploratory wells were drilled in our Licking River project, where we have development rights and a 50% interest in currently constrained gathering infrastructure on acreage spanning six counties in eastern Kentucky.

Participation Rights. The interests in some of our operated properties in the Appalachian Basin, primarily our Leatherwood field, are subject to participation rights retained by the mineral interest owners for up to 50% of the working interest in wells drilled on the covered acreage. During the first nine months of 2008, we had third-party participation in Leatherwood for average working interests of 14.3% in our vertical wells and 38.75% in our horizontal wells.

Producing Activities

Regional Advantages. Our proved reserves, both developed and undeveloped, are concentrated in the southern portion of the Appalachian Basin. 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. The proximity of this region to major east coast gas markets generates realization premiums above Henry Hub spot prices, 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 initiatives limiting the upward range of pipeline throughput to 1.1 Dth per Mcf, we constructed a processing plant with a joint venture partner in Rogersville, Tennessee for liquids extraction from our Appalachian production delivered through the NGAS Gathering system. The plant was brought on line in January 2008, ensuring our compliance with the new energy content standard. During the first nine months of 2008, our sales of extracted liquids have substantially offset the reduction in energy-related yields from our Appalachian gas production.

Oil and Gas Production. The following table shows our total production volumes and average sales prices for natural gas, oil and natural gas liquids during the three months and nine months ended September 30, 2008 and 2007 and for the year ended December 31, 2007.

	Three Months Ended September 30,		Nine Months Ended September 30,		Year Ended December 31,
	2008	2007	2008	2007	2007
Production volumes:					
Natural gas (Mcf).....	760,401	750,181	2,268,929	2,109,831	2,950,690
Oil (Bbl).....	16,235	13,056	44,718	44,398	57,738
Natural gas liquids (gallons).....	1,202,292	22,218	2,930,974	118,057	154,797
Equivalents (Mcf).....	947,986	830,464	2,778,668	2,386,549	3,310,665
Average sales prices:					
Natural gas (per Mcf)	\$ 9.80	\$ 7.64	\$ 9.40	\$ 8.25	\$ 8.19
Oil (per Bbl)	110.26	71.09	106.06	58.99	64.97
Natural gas liquids (per gallon)	1.65	1.45	1.64	1.31	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 September 30, 2008, we have contracts in place for approximately 85% of our gas production from operated Appalachian properties at a weighted average sales price of \$9.53 per Mcf during the remaining three months of 2008 and for approximately 80% of that production at a weighted average sales price of \$9.64 per Mcf during the first six months of 2009.

Results of Operations – Three Months Ended September 30, 2008 and 2007

Revenues. The following table shows the components of our revenues for the three months ended September 30, 2008 and 2007, 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,			
	2008	% of Revenue	2007	% Change
Contract drilling.....	\$ 9,799,561	41%	\$ 6,730,929	46%
Oil and gas production.....	11,222,879	48	6,690,916	68
Gas transmission, compression and processing	<u>2,567,852</u>	<u>11</u>	<u>1,793,970</u>	43
Total	<u>\$23,590,292</u>	<u>100%</u>	<u>\$15,215,815</u>	55

Our revenue mix for the third quarter of 2008 reflects our ongoing strategy for transitioning to a more production based business, with oil and gas sales accounting for 48% of total revenues, compared to 44% of total revenues for the third quarter of 2007 and 40% for the year as a whole. We expect to sustain this trend as we continue to execute our initiatives for expanding our acreage position and working interests in core fields.

Contract drilling revenues reflect the size and timing of our drilling program initiatives, as well our ownership interest in sponsored programs. Although we receive the proceeds from private placements in sponsored programs 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. We are currently sponsoring a program for participation in up to 120 wells on non-operated properties known as the HRE fields spanning six counties in West Virginia and Virginia, where our investors will have a 75% program interest. Our contract drilling revenues in the current quarter reflect ongoing operations for this program and the completion of last year's HRE program.

The growth in our production revenues for the 2008 third quarter reflects a 14% increase in production output to 948.0 Mmcf, compared to 830.5 Mmcf in the same quarter last year. These gains were moderated by a shut-in of production beginning September 7, 2008 from our Arkoma field pending repairs to a third-party pipeline, which was restored early in the fourth quarter. This was offset by the commencement of production from our Haley's Mill field in August 2008, plus strong performance from our horizontal wells in Leatherwood. We anticipate continued production growth driven by these ongoing initiatives. Principal purchasers of our production

are gas marketing intermediaries. Approximately 62% of our natural gas production in the current quarter was sold under fixed-price contracts, and the balance primarily at prices determined monthly under formulas based on prevailing market indices. Realized natural gas prices averaged \$10.16 per Mcf for our Appalachian production and \$9.80 per Mcf overall during the current quarter, compared to an average overall realization of \$7.64 per Mcf in the third quarter of 2007.

Gas transmission, compression and processing revenues were driven by fees totaling \$1,241,814 for moving third-party gas through our NGAS Gathering system and \$236,787 in related processing fees for liquids extraction through our Rogersville plant. This component of revenues also includes gathering and compression fees of \$509,050 for moving our drilling program investors' share of gas through our field-wide facilities, together with contributions of \$35,933 from gas utility sales and \$135,259 from our interest in the gathering system that services a non-operated coalbed methane project in the Arkoma Basin.

Expenses. The following table shows the components of our direct and other expenses for the three months ended September 30, 2008 and 2007. 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,			
	2008	Margin	2007	Margin
Direct Expenses:				
Contract drilling.....	\$ 7,570,698	23%	\$ 5,291,342	21%
Oil and gas production.....	3,922,629	65	1,873,413	72
Gas transmission, compression and processing.....	<u>1,039,597</u>	60	<u>783,970</u>	56
Total direct expenses.....	<u>12,532,924</u>	47	<u>7,948,725</u>	48
Other Expenses:				
		% Revenue		% Revenue
Selling, general and administrative.....	3,551,908	15%	2,572,348	17%
Options, warrants and deferred compensation.....	229,209	1	261,327	2
Depreciation, depletion and amortization.....	3,318,320	14	2,493,219	16
Bad debt expense.....	342,195	1	215,000	1
Interest expense, net of interest income.....	1,446,526	6	1,753,789	12
Other, net.....	<u>87,584</u>	--	<u>(96,385)</u>	N/A
Total other expenses.....	<u>\$ 8,975,742</u>		<u>\$ 7,199,298</u>	

Contract drilling expenses reflect the level of drilling initiatives conducted through our sponsored programs. These expenses increased by 43% on a period-over-period basis and represented 77% of contract drilling revenues in current period, compared to 79% in the year-earlier period. All of our contract drilling activities in the current quarter were conducted on non-operated HRE properties in West Virginia and Virginia. 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. The increase in production expenses on a period-over-period basis primarily reflects our volumetric growth and higher severance and production taxes, as well as approximately \$725,000 in hauling costs for natural gas liquids, which we began stripping from our Appalachian production through our Rogersville plant during the first quarter of 2008. Our margins in both periods reflect cost savings realized from ownership of the NGAS Gathering system acquired in March 2006, eliminating transportation and processing fees for our share of Leatherwood, Straight Creek, Fonde and SME production delivered through the system. As a percentage of oil and gas production revenues, our production expenses were 35% in the 2008 third quarter, compared to 28% in the year-earlier period, reflecting added transportation fees for extracted natural gas liquids.

Gas transmission, compression and processing expenses in the third quarter of 2008 were 40% of associated revenues, compared to 44% in the same quarter last year. The margins for this part of our business have benefited from third-party fees generated by the NGAS Gathering system acquired two years ago. Our gas transmission, compression and processing expenses do not include capitalized costs of approximately \$2.3 million in the current quarter for extensions of our field-wide gas gathering systems and additions to dehydration and compression capacity required to bring new wells on line.

Selling, general and administrative (SG&A) expenses are comprised primarily of selling and promotional costs for our sponsored drilling programs and general overhead costs. Our SG&A expenses in the current quarter increased by 38% from the same period last year, primarily reflecting sales costs for a program launched in April 2008 for participation in up to 120 wells on non-operated properties in West Virginia and Virginia, along with overhead costs for supporting our expanded operations as a whole. As a percentage of revenues, SG&A expenses decreased from 17% in the 2007 third quarter to 15% in the current quarter.

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 \$63,390 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 increase in DD&A charges reflects substantial additions to our oil and gas properties, gas gathering systems and related equipment.

We recognized a bad debt expense of \$342,195 in the third quarter of 2008 for unreimbursed trade debt we paid on behalf of a Virginia steam company in which we previously held a 50% interest. A charge of \$215,000 in the third quarter of 2007 reflects a reserve against past due accounts receivable from oil sales to a regional refinery which subsequently filed for reorganization under the bankruptcy laws. See "Critical Accounting Policies and Estimates – Allowance for Doubtful Accounts."

Interest expense for the 2008 second quarter decreased from lower variable rates under our revolving credit facility. Draws under the credit facility were used primarily to support our ongoing drilling initiatives and enhancements of our field-wide gas gathering systems.

Deferred income tax expense recognized in both reported periods represents future tax liability at the operating company level. Although we have no current tax liability 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 and EPS. We realized net income of \$945,185 in the third quarter of 2008, compared to a net loss of \$58,564 recognized in the same quarter last year, reflecting the foregoing factors. Basic earnings per share (EPS) was \$0.04 based on 26,508,570 weighted average common shares outstanding in the current quarter, compared to EPS of \$0.00 based on 21,804,959 weighted average common shares outstanding in the third quarter of 2007.

Results of Operations – Nine Months Ended September 30, 2008 and 2007

Revenues. The following table shows the components of our revenues for the nine months ended September 30, 2008 and 2007, 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,			
	2008	% of Revenue	2007	% Change
Contract drilling.....	\$24,027,035	39%	\$23,435,852	3%
Oil and gas production.....	30,891,933	49	20,174,095	53
Gas transmission, compression and processing	7,662,504	12	5,628,950	36
Total	<u>\$62,581,472</u>	<u>100%</u>	<u>\$49,238,897</u>	27

Contract drilling revenues reflect the size and timing of our drilling program initiatives, as well our ownership interest in sponsored programs. All of our contract drilling activities in the current period were conducted on non-operated HRE properties in West Virginia and Virginia. Drilling operations for our 2007 year-end HRE program were substantially completed during the first two quarters this year and began for our current

HRE drilling program in the second quarter. Our contract drilling revenues for the balance of the year will be driven by the size of that program, which will participate in up to 120 wells being drilled by our joint venture partner, including a number of horizontal wells.

The growth in our production revenues during the first nine months of 2008 reflects a 16% increase in production output to 2,778.7 Mmcfe, compared to 2,386.5 Mmcfe in the same period last year. Our volumetric growth was driven by added production from wells brought on line in the last twelve months. We anticipate ongoing production gains as we continue to bring completed wells on line, including substantial contributions from our horizontal wells and New Albany shale project. Realized natural gas prices averaged \$9.92 per Mcf for our Appalachian production and \$9.40 per Mcf overall during the current period, compared to an average overall realization of \$8.25 per Mcf in the year-earlier period. Approximately 55% of our natural gas production in the first nine months of 2008 was sold under fixed-price contracts, and the balance primarily at prices determined monthly under formulas based on prevailing market indices.

Gas transmission, compression and processing revenues were driven by fees totaling \$3,722,478 for moving third-party gas through our NGAS Gathering system and \$533,037 in related processing fees for liquids extraction through our Rogersville plant. This component of revenues also includes gathering and compression fees of \$1,462,980 for moving our drilling program investors' share of gas through our field-wide facilities, together with contributions of \$370,249 from gas utility sales and \$343,299 from our interest in the gathering system that services a non-operated coalbed methane project in the Arkoma Basin.

Expenses. The following table shows the components of our direct and other expenses for the nine months ended September 30, 2008 and 2007. Percentages listed in the table reflect margins for each component of direct expenses and percentages of total revenue for each component of other expenses.

	Nine Months Ended September 30,			
	2008	Margin	2007	Margin
Direct Expenses:				
Contract drilling.....	\$18,447,544	23%	\$18,391,079	22%
Oil and gas production.....	9,794,679	68	5,355,613	73
Gas transmission, compression and processing.....	3,087,391	60	2,663,406	53
Impairment of oil and gas assets.....	--	N/A	964,000	N/A
Total direct expenses.....	<u>31,329,614</u>	50	<u>27,374,098</u>	44
Other Expenses:				
		% Revenue		% Revenue
Selling, general and administrative.....	10,282,485	16%	9,636,594	20%
Options, warrants and deferred compensation.....	601,691	1	931,627	2
Depreciation, depletion and amortization.....	9,451,272	15	7,160,865	15
Bad debt expense.....	749,035	1	215,000	--
Interest expense, net of interest income.....	4,049,336	6	4,379,018	9
Other, net.....	<u>115,939</u>	--	<u>41,520</u>	--
Total other expenses.....	<u>\$25,249,758</u>		<u>\$22,364,624</u>	

Contract drilling expenses were consistent on a period-over-period basis and represented 77% of contract drilling revenues in current period, compared to 78% in the year-earlier period. The overall contraction in this part of our business during the last two years reflects a planned phase-out of drilling programs to participate in developing our operated properties in the Appalachian Basin. 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 for the first nine months of 2008 increased 83% from the same period last year. In addition to our volumetric growth, this reflects higher severance and production taxes, as well as approximately \$1.7 million in hauling costs for natural gas liquids, which we began stripping from our Appalachian production through our Rogersville plant during the first quarter of 2008. Our margins in both reported periods reflect cost savings realized from ownership of the NGAS Gathering system acquired in March 2006, eliminating transportation and processing fees for our share of Appalachian production delivered through the system. As a percentage of oil and gas production revenues, our production expenses were 32% in the first nine months of 2008, compared to 27% in the year-earlier period, primarily reflecting start-up costs for bringing our Rogersville processing plant and Fonde

system on line and added transportation fees for extracted natural gas liquids.

Gas transmission, compression and processing expenses in the first nine months of 2008 were 40% of associated revenues, compared to 47% in the same period last year. The margins for this part of our business have benefited from third-party fees generated by the NGAS Gathering system acquired two years ago. Our gas transmission, compression and processing expenses do not include capitalized costs of approximately \$9.2 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.

In the second quarter of 2007, we expensed all of the suspended exploratory well costs for the remaining 27 wells in a 30-well program we began late in 2005 to test the New Albany shale formation on the eastern rim of the Illinois Basin in western Kentucky. This resulted in an impairment charge of \$964,000 in the carrying value of our position, in addition to a charge of \$178,700 recognized for the first three wells in that program during 2006.

SG&A expenses in the first nine months of 2008 increased by 7% year-over-year, reflecting the higher level and cost of drilling program sales. This component of SG&A is subject to considerable fluctuation based on the timing of drilling program sales, which are generally higher in the second half of the year. As a percentage of revenues, SG&A expenses decreased from 20% in the first nine months of 2007 to 16% in the current 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 \$269,066 for deferred compensation cost.

The increase in DD&A charges for the current period reflects substantial additions to our oil and gas properties, gas gathering systems and related equipment. We recognize DD&A 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.

We recognized bad debt expenses aggregating \$749,035 in the first nine months of 2008. A first quarter charge of \$347,840, coupled with a prior period reserve, represents the entire amount due for oil sales to a regional refinery prior to its filing for reorganization under the bankruptcy laws last year. A second quarter charge of \$59,000 reflects a writeoff of a non-performing loan to a regional operator on a three-well project in Texas. In the third quarter of 2008, we recognized a bad debt expense of \$342,195 for unreimbursed trade debt we paid on behalf of a Virginia steam company in which we previously held a 50% interest. See "Critical Accounting Policies and Estimates – Allowance for Doubtful Accounts."

Interest expense for the first nine months of 2008 decreased from lower variable rates under our revolving credit facility. Draws under the credit facility were used primarily to support our ongoing drilling initiatives and enhancements of our field-wide gas gathering systems.

We recognize deferred income tax expense based on future tax liability at the operating company level. Although we have no current tax liability 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 and EPS. We realized net income of \$2,629,636 in the first nine months of 2008, compared to a net loss of \$1,073,252 recognized in the same period last year, reflecting the foregoing factors. Basic EPS was \$0.10 based on 26,364,158 weighted average common shares outstanding in the current period, compared to EPS of \$(0.05) based on 21,798,275 weighted average common shares outstanding in year-earlier period.

The results of operations for the three months and nine months ended September 30, 2008 are not necessarily indicative of results to be expected for the full year.

Liquidity and Capital Resources

Liquidity. Net cash of \$15,380,333 was provided by operating activities for the first nine months of 2008. During the period, we used \$38,476,188 in investing activities, most of which reflects net additions to our oil and gas properties and gathering systems. These investments were funded in part with net cash of \$20,961,386 from financing activities, primarily reflecting draws under our revolving credit facility. As a result of these activities, coupled with a more stringent cash management policy, our net cash decreased from \$2,816,678 at the end of last year to \$682,209 at September 30, 2008.

As of September 30, 2008, we had a working capital deficit of \$2,144,916. This reflects wide fluctuations in our current assets and liabilities from the timing of customer deposits and expenditures under drilling contracts with our sponsored programs. Since these fluctuations are normalized over relatively short time periods, we do not consider working capital to be a reliable measure of liquidity. Our working capital position at the end of the third quarter this year is not expected to have an adverse effect on our financial condition or results of operations in future periods.

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 is 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 provide the infrastructure to support their development on terms that are economically and operationally advantageous.

Historically, 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 ongoing reserve and infrastructure development and acquisition activities. Until recently, we have also relied on participation in our operated drilling initiatives by outside investors in our sponsored programs. With the evolution of our business model for accelerating organic growth by retaining all of our available working interest in wells drilled on operated properties, we have limited our use of drilling programs to participation in our non-operated initiatives. While we are committed to continue expanding our reserves and production through the drillbit, we are addressing current conditions in the financial and energy markets by reducing capital spending in line with our anticipated cash flow from operations and available funding under our revolving credit facility. With our critical infrastructure in place to provide deliverability for our production at a low cash cost, this will allow us to continue delivering organic growth, although at lower rates than we could achieve with access to the capital markets. If market conditions improve, we would expect to raise additional capital to accelerate drilling and meet our long-term resource development objectives.

We have a senior secured revolving credit facility maintained by our U.S. operating subsidiary, Daugherty Petroleum, Inc. (*DPI*), with KeyBank National Association, as agent and primary lender. The facility provides for revolving term loans and letters of credit in an aggregate amount up to \$125 million, with a scheduled maturity in September 2011. We amended the facility in May 2008 to add to the collateral package and in August 2008 to increase the borrowing base from \$75 million to \$90 million. Outstanding borrowings under the facility bear interest at fluctuating rates ranging from the agent's prime rate to 1.0% 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 proved oil and gas properties and open-access gathering facilities. As of September 30, 2008, outstanding borrowings under the facility aggregated \$64.5 million, with \$2 million in letters of credit, and the interest rate amounted to 5.5%. We are in compliance with our financial and other covenants under the credit facility at September 30, 2008.

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 \$12.94, reflecting an antidilution adjustment based on the pricing of a registered direct equity placement of our common stock at \$6.00 per share in November 2007. We will be entitled to redeem the notes at their face amount plus accrued interest if the prevailing market price of our common stock exceeds 160% of the note conversion price for specified periods. 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 prevailing 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. We will likely be dependent on additional financings to repay our outstanding long term debt at maturity. 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 program capital for participation in our non-operated initiatives. The market price for natural gas is subject to wide fluctuations in response to relatively minor changes in supply and demand, market uncertainty and a variety of other factors that are beyond our control.

We expect our cash flow from operations and anticipated borrowing base availability under our revolving credit facility to provide adequate working capital to meet our near-term capital expenditure objectives. To fully realize our long-term goals for growth in revenues and reserves, we will continue to be dependent on the credit and capital markets or other financing alternatives. As long as those markets remain constrained, we plan to reduce capital spending in line with our discretionary cash flow from operations and available funding under our revolving credit facility. If these conditions persist, we may also rely on additional drilling programs to take advantage of our established track record and selling network for these initiatives. Any prolonged constriction in the capital markets could require us to consider asset sales or other strategic arrangements to meet our long-term capital requirements or debt maturities.

Forward Looking Statements and Risk Factors

Some statements in this report are prospective and constitute forward-looking statements within the meaning of Section 21E of the Securities Exchange Act. 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. They include subsurface risks on the recoverability of hydrocarbons, operating risks involving logistical, infrastructure and regulatory issues and commercial risks stemming from the volatility of natural gas prices. A discussion of these risk factors is included in our annual report on Form 10-K for the year ended December 31, 2007. There were no material changes in these risk factors during the interim periods covered by this report.

Contractual Obligations and Commercial Commitments

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 our annual commitments under these instruments at September 30, 2008.

Year	Operating Leases			Other Commitments⁽¹⁾	Long Term Debt
	Equipment	Premises	Total		
Remainder of 2008	\$ 500,996	\$ 61,193	\$ 562,189	\$ --	\$ 6,000
2009	2,003,982	246,864	2,250,846	2,045,000	24,000
2010	1,934,902	247,815	2,182,717	--	36,245,417 ⁽²⁾
2011	1,723,650	252,389	1,976,039	--	64,524,000
2012 and thereafter	<u>643,396</u>	<u>277,329</u>	<u>920,725</u>	<u>--</u>	<u>222,818</u>
Total	<u>\$ 6,806,926</u>	<u>\$ 1,085,590</u>	<u>\$ 7,892,516</u>	<u>\$ 2,045,000</u>	<u>\$ 101,022,235</u>

(1) Reflects commitments under a purchase contract for an airplane.

(2) Excludes an allocation of \$778,583 from our 6% convertible notes in the principal amount of \$37,000,000 based on equity components of their conversion features.

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 2007 annual report on Form 10-K. 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 and 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. During 2007, we recognized an impairment charge of \$964,000 for exploratory well costs that had been capitalized for less than one year pending our assessment of reserves for the project.

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 amounts 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. As of September 30, 2008, we have contracts in place for approximately 85% of our gas production from operated Appalachian properties at a weighted average sales price of \$9.53 per Mcf during the remaining three months of 2008 and for approximately 80% of our that production at a weighted average sales price of \$9.53 per Mcf during the first six months of 2009.

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, 2008, 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, 2008 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, 2008.

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

<u>Exhibit Number</u>	<u>Description of Exhibit</u>
3.1	Notice of Articles, certified on June 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 June 29, 2004).
3.2	Alteration to Notice of Articles, certified on June 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 June 29, 2004).
3.3	Articles dated June 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 June 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 June 30, 2004).
- 10.4 Asset Purchase and Sale Agreement dated as of January 17, 2006 among Duke Energy Gas Services, LLC, NGAS Gathering, LLC and Daugherty Resources, Inc. (incorporated by reference to Exhibit 10.1 to current report on Form 8-K [File No. 0-12185] dated January 19, 2006).
- 10.5 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).
- 10.6 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).
- 10.7 Amendment No. 1 dated as of August 4, 2008 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 10.7 to Quarterly Report on Form 10-Q [File No. 0-12185] for the quarter ended June 30, 2008).
- 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 31, 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 31, 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 31, 2004).
- 10.11 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).
- 10.12 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).
- 10.13 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).
- 10.14 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 9 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 5, 2008

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**

In connection with the quarterly report of NGAS Resources, Inc. on Form 10-Q for the quarter ended September 30, 2008, as filed with the Securities Exchange Commission on the date hereof under the Securities Exchange Act of 1934, the undersigned certifies pursuant to Rule 13a-14(a) or 15d-14(a) under the Exchange Act 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 consolidated 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 Rule 13a-15(e) and 15d-15(e)) for the registrant and internal control over financial reporting (as defined in Exchange Act Rule 13a-15(f) and 15d-15(f)) for the registrant, and we 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 controls over financial reporting, or caused such internal controls 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 reported fiscal quarter that has materially affected or is reasonably likely to materially affect the registrant's internal control over financial reporting.
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:
 - (a) all significant deficiencies and material weaknesses in the design or operation of internal controls 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.

/s/ WILLIAM S. DAUGHERTY

William S. Daugherty
Chairman, Chief Executive Officer and President
November 5, 2008

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

In connection with the quarterly report of NGAS Resources, Inc. on Form 10-Q for the quarter ended September 30, 2008, as filed with the Securities Exchange Commission on the date hereof under the Securities Exchange Act of 1934, the undersigned certifies pursuant to Rule 13a-14(a) or 15d-14(a) under the Exchange Act 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 consolidated 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 reported 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 Rule 13a-15(e) and 15d-15(e) under the Exchange Act) for the registrant and internal control over financial reporting (as defined in Rule 13a-15(f) and 15d-15(f) under the Exchange Act) for the registrant, and we have:
 - (a) designed such disclosure controls and procedures, or caused such disclosure control 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 controls over financial reporting, or caused such disclosure control and procedures to be designed under our supervision, to provide reasonable assurances 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 those disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
 - (d) disclosed in the report any change in the registrant's internal control over financial reporting that occurred during the reported fiscal quarter that has materially affected or is reasonably likely to materially affect the registrant's internal control over financial reporting.
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:
 - (a) all significant deficiencies and material weaknesses in the design or operation of internal controls 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.

/s/ MICHAEL P. WINDISCH

Michael P. Windisch
Chief Financial Officer
November 5, 2008

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

In connection with the quarterly report of NGAS Resources, Inc. on Form 10-Q for the quarter ended September 30, 2008, as filed with the Securities Exchange Commission on the date hereof under the Securities Exchange Act of 1934, the undersigned, William S. Daugherty, certifies pursuant to Rule 13a-14(b) or 15d-14(b) under the Exchange Act that:

1. The report fully complies with the requirements of Section 13(a) or 15(d) of the Exchange Act; 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.

/s/ WILLIAM S. DAUGHERTY

William S. Daugherty
Chairman, Chief Executive Officer and President
November 5, 2008

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

In connection with the quarterly report of NGAS Resources, Inc. on Form 10-Q for the quarter ended September 30, 2008, as filed with the Securities Exchange Commission on the date hereof under the Securities Exchange Act of 1934, the undersigned, Michael P. Windisch, certifies pursuant to Rule 13a-14(b) or 15d-14(b) under the Exchange Act that:

1. The report fully complies with the requirements of Section 13(a) or 15(d) of the Exchange Act; 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.

/s/ MICHAEL P. WINDISCH

Michael P. Windisch
Chief Financial Officer
November 5, 2008