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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, 2006**

**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 (each as defined in Rule 12b-2) or a non-accelerated filer.

Large accelerated filer

Accelerated filer

Non-accelerated filer

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 equity, as of the latest practicable date.

**Title of Class**  
**Common Stock**

**Outstanding at November 3, 2006**  
**21,635,215**

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# NGAS RESOURCES, INC.

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### Forward-Looking Statements

Some matters discussed in this report are prospective and constitute forward-looking statements within the meaning of the Private Litigation Reform Act of 1995 that involve risks and uncertainties. Other than statements of historical fact, all statements that address our future activities, events, outcomes and other matters we plan, expect, budget, intend or estimate (and other similar expressions) are forward-looking statements. While we believe these forward-looking statements are based on reasonable assumptions, they involve known and unknown risks, uncertainties and other factors that may cause future results to differ materially from those discussed or implied in this report. Additional information about issues that could cause actual results to differ from our forward-looking statements is provided in our annual report on Form 10-K for the year ended December 31, 2005.

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### Additional Information

We file annual, quarterly and other reports and information with the Securities Exchange Commission. Promptly after their filing, we provide access to these reports without charge on our website at [www.ngas.com](http://www.ngas.com).

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# NGAS RESOURCES, INC.

## CONDENSED CONSOLIDATED BALANCE SHEETS

(Unaudited)

	<b>September 30,</b>	<b>December 31,</b>
	<b>2006</b>	<b>2005</b>
<b>ASSETS</b>		
Current assets:		
Cash.....	\$ 5,657,412	\$ 23,944,252
Accounts receivable.....	14,475,482	6,883,700
Prepaid expenses and other current assets.....	1,189,185	3,161,847
Loans to related parties.....	7,147	26,235
Total current assets.....	<u>21,329,226</u>	<u>34,016,034</u>
Bonds and deposits.....	533,695	432,695
Oil and gas properties.....	144,096,561	105,785,340
Property and equipment.....	3,177,635	2,934,169
Loans to related parties.....	259,251	264,377
Deferred financing costs.....	2,403,315	2,377,791
Other non-current assets.....	1,369,674	650,000
Goodwill.....	<u>313,177</u>	<u>313,177</u>
Total assets.....	<u>\$173,482,534</u>	<u>\$146,773,583</u>
<b>LIABILITIES</b>		
Current liabilities:		
Accounts payable.....	\$ 7,147,859	\$ 5,439,437
Accrued liabilities.....	5,920,257	5,788,554
Customers' drilling deposits.....	3,095,574	23,627,975
Long term debt, current portion.....	<u>24,000</u>	<u>24,000</u>
Total current liabilities.....	16,187,690	34,879,966
Future income taxes.....	6,383,735	3,881,755
Long term debt.....	74,840,531	34,947,905
Deferred compensation.....	<u>1,273,974</u>	<u>836,568</u>
Total liabilities.....	<u>98,685,930</u>	<u>74,546,194</u>
<b>SHAREHOLDERS' EQUITY</b>		
Common stock, no par value, 100,000,000 shares authorized, 21,635,215 shares issued (2005 – 21,357,628).....		
	83,592,086	82,371,189
21,100 shares held in treasury, at cost.....	(23,630)	(23,630)
Paid-in capital – options and warrants.....	2,872,114	2,743,806
Contributed surplus.....	1,484,287	1,748,926
9,185 shares to be issued.....	<u>45,925</u>	<u>45,925</u>
	87,970,782	86,886,216
Accumulated deficit.....	<u>(13,174,178)</u>	<u>(14,658,827)</u>
Total shareholders' equity.....	<u>74,796,604</u>	<u>72,227,389</u>
Total liabilities and shareholders' equity.....	<u>\$173,482,534</u>	<u>\$146,773,583</u>

*See accompanying notes.*

# NGAS RESOURCES, INC.

## CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS

(Unaudited)

	Three Months Ended		Nine months Ended	
	September 30,		September 30,	
	2006	2005	2006	2005
<b>REVENUE</b>				
Contract drilling.....	\$ 7,726,332	\$ 10,581,000	\$ 39,167,106	\$ 34,897,000
Oil and gas production .....	5,560,470	4,199,754	17,700,437	10,583,245
Gas transmission and compression .....	<u>1,564,662</u>	<u>302,694</u>	<u>3,642,818</u>	<u>1,049,168</u>
Total revenue.....	<u>14,851,464</u>	<u>15,083,448</u>	<u>60,510,361</u>	<u>46,529,413</u>
<b>DIRECT EXPENSES</b>				
Contract drilling .....	6,180,299	8,361,324	30,723,788	27,349,389
Oil and gas production .....	1,517,471	1,192,036	4,500,879	2,841,551
Gas transmission and compression .....	<u>532,650</u>	<u>252,743</u>	<u>1,706,948</u>	<u>880,611</u>
Total direct expenses .....	<u>8,230,420</u>	<u>9,806,103</u>	<u>36,931,615</u>	<u>31,071,551</u>
<b>OTHER EXPENSES (INCOME)</b>				
Selling, general and administrative .....	2,635,522	3,000,577	10,274,430	9,019,312
Options, warrants and deferred compensation ..	363,167	362,290	1,211,701	853,988
Depreciation, depletion and amortization .....	1,935,318	991,278	5,437,808	3,039,366
Interest expense.....	1,299,635	360,605	2,989,088	1,424,359
Interest income.....	(68,881)	(79,546)	(288,765)	(165,672)
Other, net.....	<u>(159,553)</u>	<u>69,626</u>	<u>(32,165)</u>	<u>(95,290)</u>
Total other expenses .....	<u>6,005,208</u>	<u>4,704,830</u>	<u>19,592,097</u>	<u>14,076,063</u>
<b>INCOME BEFORE INCOME TAXES.....</b>	<u>615,836</u>	<u>572,515</u>	<u>3,986,649</u>	<u>1,381,799</u>
<b>FUTURE INCOME TAX EXPENSE .....</b>	<u>479,877</u>	<u>385,318</u>	<u>2,502,000</u>	<u>993,188</u>
<b>NET INCOME.....</b>	<u>\$ 135,959</u>	<u>\$ 187,197</u>	<u>\$ 1,484,649</u>	<u>\$ 388,611</u>
<b>NET INCOME PER SHARE</b>				
Basic .....	<u>\$ 0.01</u>	<u>\$ 0.01</u>	<u>\$ 0.07</u>	<u>\$ 0.02</u>
Diluted .....	<u>\$ 0.01</u>	<u>\$ 0.01</u>	<u>\$ 0.06</u>	<u>\$ 0.02</u>
<b>WEIGHTED AVERAGE COMMON SHARES OUTSTANDING:</b>				
Basic.....	<u>21,552,294</u>	<u>17,583,061</u>	<u>21,462,856</u>	<u>16,432,965</u>
Diluted .....	<u>22,858,854</u>	<u>19,597,136</u>	<u>22,981,498</u>	<u>17,722,030</u>

*See accompanying notes.*

# NGAS RESOURCES, INC.

## CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

	(Unaudited)			
	Three Months Ended September 30,		Nine months Ended September 30,	
	<u>2006</u>	<u>2005</u>	<u>2006</u>	<u>2005</u>
<b>OPERATING ACTIVITIES</b>				
Net income .....	\$ 135,959	\$ 187,197	\$ 1,484,649	\$ 388,611
Adjustments to reconcile net income to net cash provided by (used in) operating activities:				
Incentive bonus paid in common shares .....	33,200	683,830	324,232	900,856
Compensation from options and warrants .....	363,167	362,290	1,211,701	853,988
Contract settlement paid in common shares .....	--	90,300	--	85,875
Depreciation, depletion and amortization .....	1,935,318	991,278	5,437,808	3,039,366
Write-down of investment .....	--	--	--	55,454
Gain on sale of assets .....	(497,800)	(11,962)	(474,827)	(24,530)
Future income taxes .....	479,857	263,513	2,501,980	871,383
Changes in assets and liabilities				
Accounts receivable .....	(4,496,175)	(1,791,503)	(7,591,782)	(3,986,885)
Prepaid expenses and other current assets .....	(289,507)	(455,484)	1,972,662	(1,390,397)
Other non-current assets .....	42,146	--	(719,674)	--
Accounts payable .....	(944,211)	1,341,585	1,708,422	2,323,067
Accrued liabilities .....	(719,353)	(108,778)	131,703	2,120,343
Customers' drilling deposits .....	198,148	3,912,000	(20,532,401)	11,194,724
Net cash provided by (used in) operating activities .....	<u>(3,759,251)</u>	<u>5,464,266</u>	<u>(14,545,527)</u>	<u>16,431,855</u>
<b>INVESTING ACTIVITIES</b>				
Proceeds from sale of assets .....	505,800	84,519	510,243	358,119
Purchase of property and equipment .....	(204,703)	(168,829)	(694,395)	(897,932)
Increase in bonds and deposits .....	(90,000)	(16,000)	(101,000)	(263,045)
Additions to oil and gas properties .....	<u>(7,884,577)</u>	<u>(7,682,544)</u>	<u>(42,929,221)</u>	<u>(21,586,498)</u>
Net cash used in investing activities .....	<u>(7,673,480)</u>	<u>(7,782,854)</u>	<u>(43,214,373)</u>	<u>(22,389,356)</u>
<b>FINANCING ACTIVITIES</b>				
Decrease in loans to related parties .....	1,798	56,084	24,214	179,887
Proceeds from issuance of common shares .....	609,039	4,327,729	896,665	5,822,365
Payments of deferred financing costs .....	(354,819)	--	(429,819)	(451,496)
Proceeds from issuance of long term debt .....	10,000,000	--	39,000,000	6,168,696
Payments of long term debt .....	(6,000)	(11,887)	(18,000)	(111,554)
Net cash provided by financing activities .....	<u>10,250,018</u>	<u>4,371,926</u>	<u>39,473,060</u>	<u>11,607,898</u>
Change in cash .....	(1,182,713)	2,053,338	(18,286,840)	5,650,397
Cash, beginning of period .....	6,840,125	15,446,431	23,944,252	11,849,372
Cash, end of period .....	<u>\$ 5,657,412</u>	<u>\$17,499,769</u>	<u>\$ 5,657,412</u>	<u>\$17,499,769</u>
<b>SUPPLEMENTAL DISCLOSURE</b>				
Interest paid .....	\$1,108,638	\$ 360,605	\$ 2,901,841	\$1,467,666
Income taxes paid .....	--	40,000	--	170,000
<b>SUPPLEMENTAL SCHEDULE OF NONCASH INVESTING AND FINANCING ACTIVITIES</b>				
Common shares issued upon conversion of notes ...	--	7,720,127	--	8,340,591

*See accompanying notes.*

# NGAS RESOURCES, INC.

## NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Unaudited)

### *Note 1. Summary of Significant Accounting Policies*

(a) General. 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, 2005. Except as noted below, 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 Resources, Inc. ("NGAS"), our direct and indirect wholly owned subsidiaries and our proportionate share of the assets, liabilities, income and expenses of our sponsored drilling programs. References to the "Company," "we," "our" or "us" include all of those accounts and interests. 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, 2006 and results of operations and cash flows for the three months and nine months ended September 30, 2006 and 2005. All material inter-company accounts and transactions for the periods presented in these interim consolidated financial statements have been eliminated on consolidation.

(c) Change in Accounting Principles. We are organized at the holding company level under the laws of British Columbia, which previously required us to prepare our consolidated financial statements in accordance with accounting principles generally accepted in Canada ("Canadian GAAP"). Recent changes in those laws now permit publicly held U.S. reporting companies to elect accounting principles generally accepted in the United States ("U.S. GAAP") and engage U.S. auditors. We made this election, beginning in 2006. Our adoption of U.S. GAAP did not have a material effect on our reported financial condition or results for prior periods and did not require any restatement of previously issued financial statements, which include reconciliations between items with different treatment under Canadian and U.S. GAAP.

(d) Estimates. The preparation of financial statements in conformity with U.S. GAAP requires our management to make estimates and assumptions that affect the amounts reported in the interim condensed consolidated financial statements and accompanying notes. Actual results could differ from those estimates.

(d) Reclassifications and Adjustments. Certain amounts reported in the condensed consolidated financial statements for the interim periods in 2005 have been reclassified to conform with the presentation in the current periods.

### *Note 2. Oil and Gas Properties*

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 these activities are summarized below.

	September 30, 2006			December 31, 2005
	Cost	Accumulated DD&A	Net	Net
Proved oil and gas properties.....	\$109,590,282	\$(10,723,521)	\$ 98,866,761	\$ 83,567,982
Unproved oil and gas properties.....	3,095,306	--	3,095,306	2,434,814
Gathering lines and well equipment.....	44,233,336	(2,098,842)	42,134,494	19,782,544
Total oil and gas properties.....	<u>\$156,918,924</u>	<u>\$(12,822,363)</u>	<u>\$144,096,561</u>	<u>\$105,785,340</u>

### **Note 3. Property and Equipment**

The following table presents the capitalized costs and accumulated depreciation for our property and equipment as of September 30, 2006 and December 31, 2005.

	<u>September 30, 2006</u>			<u>December 31,</u>
	<u>Cost</u>	<u>Accumulated Depreciation</u>	<u>Net</u>	<u>2005</u> <u>Net</u>
Land.....	\$ 12,908	\$ --	\$ 12,908	\$ 12,908
Building improvements .....	48,350	(8,982)	39,368	29,777
Machinery and equipment .....	2,522,036	(707,700)	1,814,336	1,833,591
Office furniture and fixtures .....	122,459	(45,840)	76,619	50,830
Computer and office equipment .....	535,897	(284,612)	251,285	271,420
Vehicles.....	<u>1,498,113</u>	<u>(514,994)</u>	<u>983,119</u>	<u>735,643</u>
Total property and equipment.....	<u>\$4,739,763</u>	<u>\$(1,562,128)</u>	<u>\$3,177,635</u>	<u>\$2,934,169</u>

### **Note 4. Deferred Financing Costs**

Financing costs for our convertible note private placements and secured credit facility are initially capitalized and amortized at rates based on the terms of the underlying debt instruments. These costs include \$354,819 incurred in the third quarter of 2006 for our new credit facility. 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 \$2,403,315 at September 30, 2006 and \$2,377,791 at December 31, 2005, net of accumulated amortization totaling \$783,031 and \$378,736, respectively.

### **Note 5. Goodwill**

Goodwill of \$1,789,564 was recorded in connection with our acquisition of Daugherty Petroleum, Inc. in 1993 and was amortized over ten years on a straight-line basis until 2002, when we adopted the Canadian equivalent of Statement 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, 2006 and December 31, 2005, with unamortized goodwill of \$313,177.

### **Note 6. Customer Drilling Deposits**

We sponsor and manage drilling programs to participate in our drilling initiatives, in which we maintain non-promoted interests ranging from 12.5% to 75%. Historically, we conducted drilling operations under turnkey contracts with our sponsored drilling programs, requiring us to drill and complete wells at specified prices and entitling us to any surplus if the contract price exceeded our costs. In 2006, we changed the structure of our new drilling programs from turnkey pricing to cost plus, with a view to reducing our exposure to price volatility for drilling services, equipment and steel casing requirements. Under both structures, net proceeds received under drilling contracts with sponsored programs are recorded as customers’ 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. Customer drilling deposits aggregating \$3,095,574 at September 30, 2006 and \$23,627,975 at December 31, 2005 represent unapplied drilling contract payments for wells that were not yet drilled as of the balance sheet dates.

### **Note 7. Long Term Debt**

(a) *Convertible Notes.* We issued several series of convertible notes in private placements to finance part of our drilling and acquisition activities. During 2005, the notes of all prior series were converted by their holders, either voluntarily or in response to our redemption calls, resulting in our issuance of 3,439,478 common shares

during the year. In December 2005, we completed an institutional private placement of a new series of 6% convertible notes due December 15, 2010 in the aggregate principal amount of \$37 million, all of which remained outstanding at September 30, 2006, with a conversion price of \$14.34. We also issued warrants in the transaction, which expired unexercised in August 2006. See Note 8 – Capital Stock.

The conversion price of the notes is subject to adjustment for certain dilutive issuances of common stock. The purchase agreement for the notes also provides holders with certain participation rights in future financing transactions. If a holder elects to convert a note before the second anniversary of the issuance date, unless the prevailing market price of our common stock exceeds 160% of the conversion price, the holder will be entitled to a payment equal to the difference between two years' interest on the converted note and the interest already paid on the note, payable at our option in cash or in common shares. After that date, if the prevailing market price of the common stock exceeds 160% of the conversion price, we may redeem any unconverted notes at a redemption price equal to their principal amount plus accrued and unpaid interest. Any notes that are neither redeemed nor converted prior to maturity will be repayable in cash or in common shares. Any common shares issued for interest payments on converted notes or upon redemption at their maturity will generally be valued for that purpose at 92.5% of their prevailing market price.

(b) *Credit Facility.* In September 2006, we entered into a credit agreement with KeyBank National Association, as agent and primary lender. The credit agreement provides our operating subsidiary with a senior secured revolving credit facility that replaces its prior credit facility with KeyBank, which had a scheduled maturity date of July 31, 2007 and a borrowing base of \$35 million. The new facility has a five-year maturity for revolving term loans and letters of credit in an aggregate amount up to \$125 million, with a current borrowing base of \$50 million. Under the terms of the credit agreement, outstanding borrowings bear interest at fluctuating rates ranging from the agent's prime rate to 0.75% above that rate, depending on the amount of borrowing base utilization. Alternatively, we may elect Eurodollar based pricing from 1.5% to 2.5% above quoted LIBOR rates, depending on its borrowing base utilization. The credit agreement also provides for commitment fees ranging from 0.375% to 0.5% of the unused borrowing base. As of September 30, 2006, outstanding borrowings under the facility aggregated \$39 million, with \$2 million in letters of credit. The facility is secured by liens on our interests in producing wells and field-wide gathering systems. Obligations under the facility are guaranteed by NGAS.

(c) *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 net smelter returns or other production revenues, the property has remained inactive. The remaining acquisition debt was \$348,818 at September 30, 2006 and \$366,818 at December 31, 2005.

(d) *Total Long Term Debt and Maturities.* The following tables summarize our total long term debt at September 30, 2006 and December 31, 2005 and the principal payments due each year through 2010 and thereafter.

	<u>Principal Amount Outstanding</u>	
	<u>September 30,</u> <u>2006</u>	<u>December 31,</u> <u>2005</u>
Total long term debt (including current portion) <sup>(1)</sup> .....	\$ 74,864,531	\$ 34,971,905
Less current portion .....	<u>24,000</u>	<u>24,000</u>
Total long term debt <sup>(1)</sup> .....	<u>\$ 74,840,531</u>	<u>\$ 34,947,905</u>

#### **Maturities of Debt**

Remainder of 2006 .....	\$ 6,000
2007 .....	24,000
2008 .....	24,000
2009 .....	24,000
2010 and thereafter .....	74,786,531

(1) Reflects allocations of \$1,484,287 at September 30, 2006 and \$2,394,913 at December 31, 2005 from our 6% convertible notes in the principal amount of \$37,000,000 based on equity components of their conversion features and related warrants.

**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, 2006 or December 31, 2005.

(b) Common Shares. The following tables reflect transactions involving our common stock during the periods presented.

	<u>Number of Shares</u>	<u>Amount</u>
<u>Common Shares Issued</u>		
Balance, December 31, 2004 .....	15,605,208	\$ 54,929,887
Issued to employees as incentive bonus .....	154,415	900,856
Issued upon exercise of stock options and warrants .....	2,143,527	10,983,938
Issued upon conversion of convertible notes .....	3,439,478	15,466,208
Issued for contract settlement .....	<u>15,000</u>	<u>90,300</u>
Balance, December 31, 2005 .....	21,357,628	82,371,189
Issued to employees as incentive bonus .....	43,315	324,232
Issued upon exercise of stock options and warrants .....	<u>234,272</u>	<u>896,665</u>
Balance, September 30, 2006 .....	<u>21,635,215</u>	<u>\$ 83,592,086</u>
<u>Paid In Capital – Options and Warrants</u>		
Balance, December 31, 2004 .....		\$ 1,796,504
Recognized .....		1,452,410
Exercised .....		<u>(505,108)</u>
Balance, December 31, 2005 .....		2,743,806
Recognized .....		774,295
Expired .....		(565,946)
Accreted <sup>(1)</sup> .....		<u>(80,041)</u>
Balance, September 30, 2006 .....		<u>\$ 2,872,114</u>
<u>Contributed Surplus</u>		
Balance, December 31, 2004 .....		\$ --
Allocated .....		<u>1,748,926</u>
Balance, December 31, 2005 .....		1,748,926
Accreted <sup>(1)</sup> .....		<u>(264,639)</u>
Balance, September 30, 2006 .....		<u>\$ 1,484,287</u>
<u>Common Shares to be Issued</u>		
Balance, December 31, 2004 .....	10,070	\$ 50,350
Contract settlement paid in cash in lieu of common shares .....	<u>(885)</u>	<u>(4,425)</u>
Balance, September 30, 2006 and December 31, 2005 .....	<u>9,185</u>	<u>\$ 45,925</u>

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

(c) Stock Options and Awards. We maintain three stock plans for the benefit of our directors, officers, employees and, in the case of the second and third plans, 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 under the third plan may be subject to vesting conditions and trading restrictions specified at the time of grant. During 2005 and the first nine months of 2006, stock awards and option grants were made under the third plan for a total of 834,415 shares and 43,315 shares, respectively. The following table shows transactions in stock options during 2005 and the first nine months of 2006.

	<u>Issued</u>	<u>Exercisable</u>	<u>Weighted Average Exercise Price</u>
Balance, December 31, 2004 .....	2,385,000	370,000	\$ 3.58
Issued <sup>(1)</sup> .....	860,000		6.71
Exercised .....	<u>(260,000)</u>		1.43
Balance, December 31, 2005 .....	2,985,000	571,250	4.67
Vested .....	--	509,583	4.26
Exercised .....	(135,000)	(135,000)	4.05
Forfeited .....	<u>(35,000)</u>	--	6.02
Balance, September 30, 2006 .....	<u>2,815,000</u>	<u>945,833</u>	4.68

(1) Vesting in increments from February 25, 2007 through February 25, 2009.

At September 30, 2006, the exercise prices of options outstanding under our stock option plans ranged from \$1.02 to \$7.04 per share, and their weighted average remaining contractual life was 3.14 years. The following table provides additional information on the terms of stock options outstanding at September 30, 2006.

<u>Options Issued and Outstanding</u>				<u>Options Exercisable</u>	
<u>Exercise Price or Range</u>	<u>Number</u>	<u>Weighted Average Remaining Life (years)</u>	<u>Weighted Average Exercise Price</u>	<u>Number</u>	<u>Weighted Average Exercise Price</u>
\$ 1.02	145,000	1.26	\$ 1.02	145,000	\$ 1.02
4.03 4.09	1,845,000	3.00	4.05	752,500	4.07
6.02 7.04	<u>825,000</u>	3.80	6.74	<u>48,333</u>	6.02
	<u>2,815,000</u>			<u>945,833</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 under its Canadian GAAP equivalent 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 \$774,295 and \$511,135 in the nine months ended September 30, 2006 and 2005, respectively.

(d) *Common Stock Purchase Warrants.* We have issued common stock purchase warrants in various financing transactions. The exercise prices of warrants outstanding at September 30, 2006 ranged from \$4.03 to \$5.65 per share, and their weighted average remaining contractual life was 0.44 years. The following table shows transactions in stock options during 2005 and the first nine months of 2006.

	<u>Issued</u>	<u>Exercisable</u>	<u>Weighted Average Exercise Price</u>
Balance, December 31 2004 .....	2,422,055	2,422,055	\$ 4.96
Issued in financing transactions .....	945,809		13.04
Exercised .....	(1,883,527)		5.37
Expired .....	<u>(169,954)</u>		2.91
Balance, December 31, 2005 .....	1,314,383	1,314,383	10.46
Exercised .....	(99,272)		3.52
Expired .....	<u>(1,102,767)</u>		11.59
Balance, September 30, 2006 .....	<u>112,344</u>	112,344	5.51

**Note 9. Income Per Share**

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

	<b>Three Months Ended September 30,</b>		<b>Nine Months Ended September 30,</b>	
	<b>2006</b>	<b>2005</b>	<b>2006</b>	<b>2005</b>
<b>Diluted EPS</b>				
<u>Numerator:</u>				
Net income as reported for basic EPS .....	\$ 135,959	\$ 187,197	\$ 1,484,649	\$ 388,611
Adjustments to income for diluted EPS.....	--	--	--	--
Net income for diluted EPS.....	<u>\$ 135,959</u>	<u>\$ 187,197</u>	<u>\$ 1,484,649</u>	<u>\$ 388,611</u>
<u>Denominator:</u>				
Weighted average shares for basic EPS.....	21,552,294	17,583,061	21,462,856	16,432,965
Effect of dilutive securities:				
Stock options.....	1,239,174	1,281,751	1,361,171	899,062
Warrants.....	67,386	732,324	157,471	390,003
Adjusted weighted average shares and assumed conversions for diluted EPS .....	<u>22,858,854</u>	<u>19,597,136</u>	<u>22,981,498</u>	<u>17,722,030</u>
Basic EPS.....	<u>\$ 0.01</u>	<u>\$ 0.01</u>	<u>\$ 0.07</u>	<u>\$ 0.02</u>
Diluted EPS .....	<u>\$ 0.01</u>	<u>\$ 0.01</u>	<u>\$ 0.06</u>	<u>\$ 0.01</u>

**Note 10. Segment Information**

We have two reportable segments based on management responsibility and key business operations. The following table presents summarized financial information on these business segments.

	<b>Three Months Ended September 30,</b>		<b>Nine months Ended September 30,</b>	
	<b>2006</b>	<b>2005</b>	<b>2006</b>	<b>2005</b>
<b>Revenue, net:</b>				
Oil and gas development .....	\$ 14,851,464	\$ 15,083,448	\$ 60,510,361	\$ 46,529,413
Corporate .....	--	--	--	--
Total .....	<u>14,851,464</u>	<u>15,083,448</u>	<u>60,510,361</u>	<u>46,529,413</u>
<b>DD&amp;A:</b>				
Oil and gas development .....	1,779,606	916,266	4,976,430	2,781,808
Corporate .....	155,712	75,012	461,378	257,558
Total .....	<u>1,935,318</u>	<u>991,278</u>	<u>5,437,808</u>	<u>3,039,366</u>
<b>Interest expense:</b>				
Oil and gas development .....	744,635	160,889	1,324,088	686,180
Corporate .....	555,000	199,716	1,665,000	738,179
Total .....	<u>1,299,635</u>	<u>360,605</u>	<u>2,989,088</u>	<u>1,424,359</u>
<b>Net income (loss):</b>				
Oil and gas development .....	1,047,819	637,485	4,080,354	1,793,411
Corporate .....	(911,860)	(450,288)	(2,595,705)	(1,404,800)
Total .....	<u>135,959</u>	<u>187,197</u>	<u>1,484,649</u>	<u>388,611</u>
<b>Capital expenditures:</b>				
Oil and gas development .....	8,038,104	7,809,166	43,450,017	22,259,947
Corporate .....	51,176	42,207	173,599	224,483
Total .....	<u>\$ 8,089,280</u>	<u>\$ 7,851,373</u>	<u>\$ 43,623,616</u>	<u>\$ 22,484,430</u>

	<u>September 30,</u> <u>2006</u>	<u>December 31,</u> <u>2005</u>
<b>Identifiable assets:</b>		
Oil and gas development .....	\$ 170,144,340	\$ 126,590,249
Corporate .....	<u>3,338,194</u>	<u>20,183,334</u>
Total .....	<u>\$ 173,482,534</u>	<u>\$ 146,773,583</u>

**Note 11. Commitments**

The following table shows our contractual obligations as of September 30, 2006 under leases for field equipment and instruments governing our other commercial commitments. Our lease rental expenses were \$1,218,427 for the nine months ended September 30, 2006 and \$704,597 for the year ended December 31, 2005.

<u>Year</u>	<u>Commercial Commitments</u>		
	<u>Operating</u> <u>Leases</u>	<u>Other</u> <u>Commitments</u>	<u>Total</u>
Remainder of 2006.....	\$ 149,979	\$ 240,000 <sup>(1)</sup>	\$ 389,979
2007 .....	601,498	--	601,498
2008 .....	292,289	100,000 <sup>(2)</sup>	392,289
2009 .....	195,000	2,045,000 <sup>(2)</sup>	2,240,000
2010 and thereafter .....	<u>97,500</u>	<u>--</u>	<u>97,500</u>
Total .....	<u>\$1,336,266</u>	<u>\$2,385,000</u>	<u>\$3,721,266</u>

(1) Reflects obligations under a guaranty for a limited liability company in which we previously held a minority interest.

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

**Note 12. Recent Accounting Standards**

FSP No. 123(R)-4. In February 2006, the Financial Accounting Standards Board (“FASB”) issued FASB Staff Position (“FSP”) No. 123(R)-4, “Classification of Options and Similar Instruments Issued as Employee Compensation that Allow for Cash Settlement upon the Occurrence of a Contingent Event.” We do not have any stock options with a cash settlement feature, and our consolidated financial statements will not be affected by this guidance.

FIN No. 48. In July 2006, the FASB issued FASB Interpretation (“FIN”) No. 48, “Accounting for Uncertainty in Income Taxes – Interpretation of FASB No. 109.” FIN No. 48 requires us to recognize the impact of a tax position on our financial statements if that position is more likely than not to be sustained on audit, based on the technical merits of the position. The provisions of FIN No. 48 are effective at the beginning of 2007, with the cumulative effect of any resulting change in accounting principle recorded as an adjustment to opening retained earnings. We are evaluating the impact of adoption FIN No. 48 and do not currently believe it will have a material affect on our consolidated financial statements.

SAB No. 108. In September 2006, the staff of the Securities and Exchange Commission issued Staff Accounting Bulletin (“SAB”) No. 108, “Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements.” SAB No. 108 provides interpretive guidance on how the effects of the carryover or reversal of prior year financial statement errors should be considered in quantifying a current year misstatement. For fiscal years ending after November 15, 2006, prior year errors must be quantified using both a balance sheet and income statement approach and evaluated based on relevant quantitative and qualitative factors in determining their materiality for disclosure purposes. We do not believe that application of this guidance will have a material affect on our consolidated financial statements.

SFAS No. 157. In September 2006, the FASB issued SFAS No. 157, “Fair Value Measurements,” which defines fair value, establishes a framework for measuring fair value and expands disclosure requirements about fair

value measurements. The guidance in SFAS No. 157 applies to fair value measurements for derivatives and other financial instruments at initial recognition and in all subsequent periods. SFAS No. 157 is generally effective for all reporting periods during fiscal years beginning after November 15, 2007. We do not expect any material impact on our consolidated financial position or results of operations from adoption of this new standard.

SFAS No. 158. In September 2006, the FASB issued SFAS No. 158, “Employers’ Accounting for Defined Benefit Pension and Other Postretirement Plans.” SFAS No. 158 requires the employer to recognize the overfunded or underfunded status of any defined benefit postretirement plan as an asset or liability on its balance sheet and to recognize changes in that status through adjustments to comprehensive income. It also requires an employer to measure the funded status of a plan as of the date of its year-end balance sheet. These requirements are effective for fiscal years ending after December 15, 2006. The adoption of SFAS No. 158 is not expected to have a material impact on our consolidated financial position, results of operations or cash flows in future periods.

FSP AUG AIR-1. In September 2006, the FASB issued FSP AUG AIR-1, “Accounting for Planned Major Maintenance Activities.” FSP AUG AIR-1 prohibits companies from accruing the future costs of periodic major overhauls and maintenance of plant and equipment as a liability. The provisions of FSP AUG AIR-1 are effective for fiscal years beginning after December 15, 2006. We do not expect the implementation of these provisions to have a material impact on our consolidated financial statements.

# 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 basins in the eastern United States that support multiple, repeatable drilling, principally in the southern portion of the Appalachian basin. We believe our extensive geological, geophysical, engineering and operating experience in this region, coupled with our ownership of gas gathering facilities and established 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.

We develop our prospects through our operating subsidiaries and our interests in sponsored drilling programs. We also construct and operate gas gathering systems and gas distribution facilities. Our principal and administrative offices are located in Lexington, Kentucky. Our common stock is traded on the Nasdaq National Market under the symbol "NGAS," and we maintain a website with information about us at [www.ngas.com](http://www.ngas.com). 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, "Mcf" means thousand cubic feet, "Bcf" means billion cubic feet and "Mcf<sub>e</sub>" means thousand cubic feet of gas equivalents.

#### *Strategy*

We have structured our business to achieve capital appreciation through growth in our natural gas reserves, production, cash flow and earnings per share. We entered 2006 with a strengthened foundation for growth by adding 140 miles to our gas gathering systems last year and increasing our capital base with a \$37 million convertible note financing at year end. We also began to leverage our team's long experience as an Appalachian developer with complementary plays in other gas basins, including an exploratory project to test the New Albany shale formation, through both vertical and horizontal drilling, on acquired acreage in the Illinois basin and a \$11.4 million acquisition of coal bed methane ("CBM") assets in the Arkoma basin. During 2005, we doubled our production to a record 1.8 Bcf<sub>e</sub>, while increasing our revenue by 30% to \$62.2 million and our estimated proved reserves by 9.2 Bcf<sub>e</sub> or 14% for the year. Our strategy for continuing to realize our operational and financial objectives emphasizes several components.

- *Acceleration of Drilling Operations.* Development drilling is our mainstay for production and reserve growth. During the first nine months of 2006, we drilled 180 gross (48.6319 net) wells, primarily through our drilling programs. See "Drilling Operations." We believe that our long and successful operating history and proven ability to drill a large number of wells year after year have positioned us as a leading player in the Appalachian basin. Over the next few years, we plan to continue our focus on developing our Leatherwood field, where we drilled 86 wells in the first nine months of 2006 and have identified over 550 additional drilling locations. We are also pursuing opportunities to capitalize on our team's experience and diversify our asset base through targeted expansion in other unconventional natural gas basins.
- *Drilling Program Financings.* Our ability to attract outside capital through our drilling programs has enabled us to capitalize on natural gas development opportunities and long range pricing expectations for this commodity. Beginning this year, we changed the structure of our new drilling programs from turnkey to cost-plus pricing, with a view to reducing our exposure to price volatility for drilling services, equipment and steel casing requirements. We launched our first cost-plus drilling program in March 2006 to participate with our joint venture partner in up to 60 natural gas wells on its acreage in Jackson and Roane Counties, West Virginia. Our second program this year is participating in six horizontal CBM wells in our Arkoma basin project. Our third 2006 drilling program will invest in a portfolio of 85 wells in four of our major Appalachian fields, where we are retaining a 75% program interest in Leatherwood development, 60% for our drilling initiatives in Amvest and Martin's Fork, 25% in Straight Creek and 20% in our Fonde field.

- *Acquisition of Additional Drilling Prospects.* We follow a disciplined capital allocation process in selecting opportunities to build our substantial inventory of drilling prospects that meet our criteria for predictable, long-lived reserves. During the fourth quarter of 2005, we acquired a significant position in approximately 14,000 acres of CBM properties in the Arkoma basin within Leflore County, Oklahoma and Sebastian County, Arkansas. We also initiated an exploratory play during 2005 in the Illinois basin on acquired tracts spanning approximately 15,500 acres within Breckinridge, Grayson, Hardin, Meade and Ohio Counties in western Kentucky. We plan to continue capitalizing on opportunities to assemble or acquire large tracts with significant unproved gas development potential. Our goal is to consolidate our position in the Appalachian basin, while also diversifying our inventory of drilling prospects in other basins that offer attractive natural gas and CBM plays.
- *Repeatable Drilling.* As of September 30, 2006, we had interests in a total of 995 wells and had identified over 1,100 additional drilling locations. Most of our wells are drilled to relatively shallow total depths up to 5,000 feet, generally encountering several predictable natural gas pay zones. We focus on repeatable prospects to reduce drilling risks, as reflected in our success rate. Historically, over 99% of our Appalachian wells have been completed as producers. The primary pay zone for most of our Appalachian wells is the Devonian shale formation. This is considered an unconventional target due to its low permeability. To be productive, natural fracturing must be present and generally must be enhanced by effective acidizing or other fracturing treatment. While this typically results in modest initial volumes and pressures, it also accounts for the low annual decline rates demonstrated by our wells in the region, many of which are expected to produce for 25 years or more. We recently implemented initiatives to leverage our core expertise with evolving technologies in horizontal drilling, which may provide advantages in extracting this type of tight gas. The initial programs are being conducted in the Arkoma basin for accelerated CBM recovery and on recently acquired acreage in the Illinois basin to test the New Albany shale formation, which has similar geologic characteristics to the Devonian shale in the Appalachian basin.
- *Extension of Gas Gathering Systems.* We construct and operate gas gathering facilities to connect our wells to interstate pipelines with access to major east coast natural gas markets. In addition to generating gas transmission and compression revenues, our 100% ownership of these systems gives us control over third-party access, providing competitive advantages in acquiring and developing nearby acreage. As of September 30, 2006, our gas gathering facilities spanned 400 miles, including 140 miles installed during 2005 and 89 miles in the first nine months of 2006, in addition to 116 miles of the NGAS Gathering open-access system acquired in March 2006. See “Recent Initiatives” below. The recent extensions to our gathering systems include a 23-mile, eight-inch steel line for connecting our wells in the Leatherwood field and a 16-mile, six-inch line that connects them to the NGAS Gathering system. As of the date of this report, we have a total of 185 wells producing to sales in Leatherwood and an additional 19 wells awaiting connection. With this infrastructure now in place, we expect to bring current and future Leatherwood wells on line soon after completion.
- *Purchase of Producing Properties.* The purchase of third party production offers a means in addition to drilling for accelerating our growth, while continuing to capitalize on our operating experience. Our acquisition criteria for producing properties include reserve life, profit enhancement potential, existing infrastructure, geographic concentration and working interest levels permitting operation of acquired properties. In the fourth quarter of 2005, we acquired a 25% interest in producing properties within the Arkoma basin, with an estimated 7.0 Bcf of proved CBM reserves, at an acquisition price of \$1.63 per Mcfe. We continuously evaluate opportunities to acquire producing properties meeting our criteria for long-lived reserves in targeted geographic areas.

### ***Recent Initiatives***

*Gathering System Acquisition.* In March 2006, we acquired an open-access gas transmission system spanning 116 miles in southeastern Kentucky and southwestern Virginia. We acquired the system through our NGAS Gathering subsidiary for \$18 million. The acquired system includes five delivery measuring and regulation stations, four compression stations and a liquids extraction plant. We operated this system since October 2004 and augmented it after the acquisition through two high-pressure lateral upgrades. Most of our Appalachian production is now delivered through the NGAS Gathering system, with current daily throughput of over 18,000 Mcf directly from the wellhead to interstate pipelines serving major east coast natural gas markets. In addition to generating substantial revenues and cost savings, ownership of the NGAS Gathering system has enhanced our deliverability and our

competitive position in the region. Unlike the gathering facilities we construct for connecting new wells in our major fields, the NGAS Gathering system is open access, and our acquisition includes existing contracts for moving third-party gas. As currently configured, the NGAS Gathering system has an estimated through-put capacity of 24,000 Mcf per day. With further compression upgrades, we can substantially increase this through-put capacity and our gas transmission revenues.

**Property Acquisition.** In November 2005, we acquired the CBM assets of Dart Energy Corporation covering approximately 14,000 gross (3,500 net) acres in the Arkoma basin within Sebastian County, Arkansas and Leflore County, Oklahoma. The acquired assets include a 25% interest in 48 producing wells, with average daily net production of 1,400 Mcfe as of the acquisition date. We also acquired a 25% interest in a limited liability company that owns and operates the gathering system servicing the project area. The purchase price for the acquired CBM interests and gas gathering assets was \$11.4 million. We also entered into a series of farmout agreements with CDX Gas, LLC, the operator of this project, covering its majority (75%) interest in new wells within the project area. Under the farmout terms, we assumed all of the future developments costs for project wells and granted CDX a carried working interest for 25% of its position, increasing to 50% of its position after payout of the wells.

**Williston Basin Leasing Initiative.** During 2005, we initiated a leasing program in the Williston basin, targeting the southwestern portion of Dunn County, North Dakota. As of September 30, 2006, our acquired position aggregated 18,411 gross (14,864 net) areas. We are offering our position in the Williston basin to regional operators, with a view to monetizing our investment in the leasing program this year.

**Purchase and Sale of Royalty Interests.** Effective August 1, 2006, we acquired overriding royalty interests averaging 2.25% under our farmout with Amvest Gas Resources for properties in Harlan County, Kentucky and Lee County, Virginia, together with related participation and pipeline capacity rights. The purchase price for the acquisition was \$1.5 million. We sold the overriding royalty interests to a third party, effective September 1, 2006, for \$2.0 million, resulting in a pre-tax gain of \$492,000 after accounting for transaction costs.

### ***Regional Advantages***

Our proved reserves, both developed and undeveloped, are concentrated in the southern portion of the Appalachian basin. This is one of the oldest and most prolific natural gas producing areas in the United States. Typically, natural gas wells in this part of the Appalachian basin recover between 100 to 500 Mmcf of reserves per drilling unit. The natural gas production, known as sweet gas, is environmentally friendly because it is substantially free of sulfur compounds, carbon dioxide or other chemical impurities. In addition, most of these wells produce no water with the gas production. This helps us minimize production (lifting) costs. Appalachian gas also has the advantage of high energy (Dth) content, ranging from 1.1 to 1.3 Dth per Mcf. Our gas sales contracts provide upward adjustments to index based pricing for throughput with an energy content above 1 Dth per Mcf, resulting in realized premiums averaging 17% over normal pipeline quality gas. Our proximity to major east coast markets generates further realization premiums above Henry Hub spot prices, contributing to enhanced cash flows and long term returns on investment.

### ***Drilling Operations***

**Drilling Program Structure.** Most of our drilling operations are conducted through sponsored programs structured to minimize drilling risks on repeatable prospects and optimize tax advantages for private investors. To develop exploratory prospects with higher risk profiles, we generally rely on smaller, specialized drilling programs with strategic and industry partners or other suitable investors. Historically, we have conducted these operations under turnkey drilling contracts, requiring us to drill and complete the wells at specified prices. We are responsible under these turnkey arrangements for any drilling and completion costs exceeding the contract price, and we are entitled to any surplus if the contract price exceeds our costs. In view of increased demand and price volatility for drilling services and equipment, we are structuring our new drilling programs on a cost-plus basis designed to share this exposure with our outside investors.

**Drilling Program Investments.** In addition to managing program operations, we invest in each drilling program on substantially the same terms as outside investors. We contribute capital to each program in proportion to our initial ownership interest, and we share program distributions in the same ratio until program distributions reach "payout," which ranges from 100% to 110% of partners' investment. After payout, we are entitled to

specified increases in our distributive share, up to 15% of the total program interests. In the first nine months of 2006, we sponsored three new drilling programs under our cost-plus pricing structure. We have a 25% stake in a \$6.5 million program for up to 60 natural gas wells being drilled by a joint venture partner on its acreage in Jackson and Roane Counties, West Virginia, and a 12.5% share of an \$11.8 million program for six horizontal CBM wells being drilled by CDX in the Arkansas sector of the Arkoma basin. See “Recent Initiatives.” In the third quarter, we launched our third 2006 drilling program for 85 wells in four of our major Appalachian fields. We are retaining a 75% program interest in 45 new Leatherwood wells planned by year end, with a 60% interest in Amvest and Martin’s Fork initiatives, 25% in Straight Creek and 20% in our Fonde field.

*Drilling Program Benefits.* Our structure for sharing drilling program costs, risks and returns helps us attract outside capital from private investors. This addresses the high capital costs of our business, enabling us to accelerate the development of our properties, generally without relinquishing control over drilling and operating decisions. The structure also provides economies of scale with operational benefits at several levels.

- Expanding our drilling budget with outside capital from program investors enables us to compete for attractive properties by increasing our drilling commitments and to maintain a larger and more capable staff than we could otherwise support if we were operating solely for our own account. It also leverages our buying power for drilling services and materials, contributing to lower overall development costs.
- Accelerating the pace of development activities through our drilling programs expands the production capacity we can make available to gas purchasers, contributing to higher and more stable sales prices for our production.
- By conducting exploratory operations through specially tailored programs, we expand our inventory of developmental locations with lower risk profiles for subsequent programs, while adding to our proved reserves, both developed and undeveloped.
- Our drilling program strategy substantially increases the number of wells we could drill solely for our own account, diversifying the risks of drilling operations.

*Participation Rights.* The leases and farmouts for drilling prospects on some of our acreage in the Appalachian basin, primarily the Leatherwood field, are subject to third-party participation rights for up to 50% of the working interests in new wells drilled on the covered acreage. We had third-party participation in our Leatherwood wells for average working interests of 26.74% during the first nine months of 2006 and 28.75% during 2005. The exercise of these rights has proportionately reduced our working interest in Leatherwood wells drilled with third-party participants. To maintain our net well position, we have increased our ownership interest in new drilling initiatives for Leatherwood development.

*Drilling Results.* We drilled 155 gross (44.3040 net) wells through our drilling programs in 2005 and an additional 180 gross (48.6319 net) wells in the first nine months of 2006. The following table shows the number of gross and net development and exploratory wells we drilled during 2005 and the first nine months of 2006. 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. All of the exploratory wells recorded in the first nine months of 2006 were drilled to test the New Albany shale formation on acreage in western Kentucky with a mix of conventional and horizontal drilling and completion techniques. Because the acreage has no existing infrastructure, the productive status of these wells is based on our preliminary tests and evaluations.

	Development Wells			Exploratory Wells		
	Productive		Dry	Productive		Dry
	Gross	Net	Gross	Gross	Net	Gross
Nine months ended						
September 30, 2006.....	149	40.5999	--	31	8.0320	--
Year ended December 31, 2005.....	151	43.1590	--	4	1.1450	--

*Production Volumes and Sales Prices.* The following table shows our total net oil and gas production volumes and average sales prices for the nine months ended September 30, 2006 and 2005 and for the year ended December 31, 2005. We also had extracted liquids and condensates that contributed \$143,770 to our production revenues in the first nine months of 2006 and \$91,931 in 2005.

	<u>Nine Months Ended</u> <u>September 30,</u>		<u>Year Ended</u> <u>December 31,</u>
	<u>2006</u>	<u>2005</u>	<u>2005</u>
Production volumes:			
Oil (Bbl).....	28,564	28,703	39,959
Natural gas (Mcf).....	1,914,458	1,141,947	1,583,922
Equivalents (Mcf).....	2,085,840	1,314,166	1,823,673
Average sales price:			
Natural gas (per Mcf).....	\$ 8.27	\$ 8.05	\$ 9.02
Oil (per Bbl).....	60.24	46.21	48.36

### ***Results of Operations – Three Months Ended September 30, 2006 and 2005***

*Revenues.* The following table shows the components of our revenues for the three months ended September 30, 2006 and 2005, together with their percentages of total revenue in the current period and percentage change on a period-over-period basis.

	<u>Three Months Ended September 30,</u>			
	<u>2006</u>	<u>% of</u> <u>Revenue</u>	<u>2005</u>	<u>%</u> <u>Change</u>
Contract drilling.....	\$ 7,726,332	52%	\$10,581,000	(27)%
Oil and gas production.....	5,560,470	37	4,199,754	32
Gas transmission and compression.....	<u>1,564,662</u>	<u>11</u>	<u>302,694</u>	417
Total.....	<u>\$14,851,464</u>	<u>100%</u>	<u>\$15,083,448</u>	(2)

Contract drilling revenues reflect both the size and the timing of our drilling program financings. Although we receive the proceeds of drilling program financings as customers' drilling deposits under the drilling contracts with the programs, we recognize revenues from drilling operations on the completed contract method as the wells are drilled, rather than when funds are received. During the third quarter of 2006, we drilled 52 gross (18,2540 net) wells. Most of the wells were drilled for our first three programs with a cost-plus structure implemented this year as part of our strategy for reducing exposure to price volatility in drilling services and supplies. With all three programs now in the active drilling phase, we anticipate a significant ramp up in revenues recognized from this sector for the balance of the year.

Our substantial growth in production revenues on a period-over-period basis reflects a 44% increase in production volumes to 692.6 Mmcfe the third quarter of 2006, with a 13% decline in our average sales price of natural gas (before certain transportation charges) to \$7.70 per Mcf. We anticipate additional volumetric growth for the balance of the year as new wells are brought on line. Principal purchasers of our natural gas production are gas marketers and customers with transmission facilities near our producing properties. Approximately 40% of our natural gas production is currently sold under fixed-price contracts and the balance primarily at prices determined monthly under formulas based on prevailing market indices.

Gas transmission and compression revenues were driven by fees totaling \$930,526 for moving third-party gas through our NGAS Gathering system, which we acquired in March 2006. See "Recent Initiatives." This component of revenues also reflects additional third-party gas gathering and compression fees from new connections through our recently completed 23-mile, eight-inch steel line for Leatherwood wells, together with \$19,348 from gas utility sales in the third quarter of 2006.

*Expenses.* The following table shows the components of our direct and other expenses for the three months ended September 30, 2006 and 2005. Percentages listed in the table reflect margins for each component of direct expenses and percentages of total revenue for each component of other expenses.

	<b>Three Months Ended September 30,</b>			
	<b>2006</b>	<b>Margin</b>	<b>2005</b>	<b>Margin</b>
Contract drilling.....	\$ 6,180,299	20%	\$ 8,361,324	21%
Oil and gas production.....	1,517,471	73	1,192,036	72
Gas transmission and compression.....	<u>532,650</u>	66	<u>252,743</u>	17
Total direct expenses.....	<u>8,230,420</u>	45	<u>9,806,103</u>	35
		<b>% Revenue</b>		<b>% Revenue</b>
Selling, general and administrative.....	2,635,522	18%	3,000,577	20%
Options, warrants and deferred compensation.....	363,167	2	362,290	2
Depreciation, depletion and amortization.....	1,935,318	13	991,278	7
Interest expense, net of interest income.....	1,230,754	8	281,059	2
Other, net.....	<u>(159,553)</u>	N/A	<u>69,626</u>	1
Total other expenses.....	<u>\$ 6,005,208</u>		<u>\$ 4,704,830</u>	

Contract drilling expenses reflect the substantial level and complexity of recent drilling activities. In the current quarter, these expenses were 80% of contract drilling revenues, compared to 79% in the third quarter of 2005. The margins for this sector reflects our transition from turnkey to cost-plus pricing for our new drilling programs, which we implemented this year with a view to reducing our exposure to price volatility for drilling services, equipment and steel casing requirements.

Production expenses for the current quarter were driven by our substantial growth in production volumes. In addition to lifting costs, production expenses include field operating and maintenance costs, related overhead, third-party transportation fees and lease operating expenses. The increase in our production expenses on a period-over-period basis was partially offset by cost savings realized in the current quarter from ownership of the NGAS Gathering system acquired in March 2006, eliminating our share of transmission fees for moving our Appalachian production for delivery through the system. See "Recent Initiatives."

Gas transmission and compression expenses in the third quarter of 2006 were 34% of associated revenues, compared to 83% in the same quarter last year. The higher current margins for this part of our business reflect the substantial revenue growth from third-party fees generated by our ownership of the NGAS Gathering system. Our gas transmission and compression expenses do not reflect our acquisition costs for that system in March 2006 or capitalized costs of \$2,216,968 in the current quarter for expansion of our field-wide gas gathering infrastructure, including additions to dehydration and compression capacity required to bring new wells on line.

Selling, general and administrative primarily reflect the timing and extent of our selling and promotional costs for sponsored drilling programs, which decreased substantially on a period-over-period basis. Our cost savings on drilling program promotion was partially offset by higher current overhead costs for supporting expanded operations as a whole, including additions to our staff and technology infrastructure.

Non-cash charges for options, warrants and deferred compensation reflect the fair value method of accounting for employee stock options, which we adopted in 2004. 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 \$145,802 for deferred compensation cost.

Depreciation, depletion and amortization 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 these charges reflects substantial additions to our oil and gas properties, gas gathering systems and related equipment, including our acquisition of the NGAS Gathering system for \$18 million in March 2006.

Interest expense increased for the third quarter of 2006 from the addition of \$37 million in convertible debt at the end of 2005 and higher overall bank borrowings to support ongoing drilling and gas gathering initiatives. In addition to our drilling budget, these include our acquisition costs of \$18 million for the NGAS Gathering system, \$11.4 million for CBM assets in the Arkoma basin and capitalized costs of approximately \$5 million for extensions of our field-wide gas gathering systems and infrastructure. See “Liquidity and Capital Resources” below.

Income tax expense recognized in the current reported period represents future tax liability at the operating company level. We have no current tax liability due to the utilization of intangible drilling costs allocated from our active development drilling programs.

*Net Income and EPS.* We realized net income of \$135,959 in the third quarter of 2006, compared to \$187,197 in the same quarter last year, reflecting the foregoing factors. Basic earnings per share (“EPS”) was \$0.01 based on 21,552,294 weighted average common shares outstanding in the current quarter, compared to \$0.01 based on 17,583,061 weighted average common shares outstanding in the third quarter of 2005. On a fully diluted basis, EPS for the current interim period was \$0.01 on 22,858,854 weighted average common shares.

***Results of Operations – Nine Months Ended September 30, 2006 and 2005***

*Revenues.* The following table shows the components of our revenues for the nine months ended September 30, 2006 and 2005, together with their percentages of total revenue in the current period and percentage change on a period-over-period basis.

	<b>Nine Months Ended September 30,</b>			
	<b>2006</b>	<b>% of Revenue</b>	<b>2005</b>	<b>% Change</b>
Contract drilling.....	\$39,167,106	65%	\$34,897,000	12%
Oil and gas production.....	17,700,437	29	10,583,245	67
Gas transmission and compression.....	<u>3,642,818</u>	<u>6</u>	<u>1,049,168</u>	247
Total.....	<u>\$60,510,361</u>	<u>100%</u>	<u>\$46,529,413</u>	30

Our revenue mix for the nine months ended September 30, 2006 reflects our strategy for transitioning to a production based business, with gas sales accounting for 29% of total revenues, compared to 23% of total revenues for the same period in 2005. We expect this trend to continue as we execute our strategy for long term production growth, complemented by our revamped structure for accelerating the development of our properties by sharing costs, risks and returns with participants in our sponsored drilling programs.

During the first nine months of 2006, we drilled 180 gross (48.6319 net) wells. Many of the wells were drilled under our turnkey contracts entered in 2005. We sponsored three programs so far this year with our new cost-plus structure as part of our strategy for reducing exposure to price volatility in drilling services and supplies. The first of those programs began operations toward the end of the first quarter, and the other programs did not account for any contract drilling revenues until the third quarter of 2006. With all of our turnkey obligations from last year’s programs now fulfilled, we expect our margins for this sector to stabilize from cost-plus drilling program operations.

Our growth in production revenues on a period-over-period basis reflects increases of 59% in production volumes to 2,085.8 Mmcfe and 3% in our average sales price of natural gas (before certain transportation charges) to \$8.27 per Mcf. We anticipate additional volumetric growth for the balance of the year as new wells are brought on line. Principal purchasers of our natural gas production are gas marketers and customers with transmission facilities near our producing properties. Approximately 40% of our natural gas production is currently sold under fixed-price contracts and the balance primarily at prices determined monthly under formulas based on prevailing market indices.

Gas transmission and compression revenues were driven by fees totaling \$1,814,561 for moving third-party gas through our NGAS Gathering system, which we acquired in March 2006. See “Recent Initiatives.” This component of revenues also reflects additional third-party gas gathering and compression fees from new connections through our recently completed 23-mile, eight-inch steel line for Leatherwood wells, together with contributions of \$175,519 from gas utility sales in the first nine months of 2006 and \$210,770 in the same period last year.

*Expenses.* The following table shows the components of our direct and other expenses for the nine months ended September 30, 2006 and 2005. Percentages listed in the table reflect margins for each component of direct expenses and percentages of total revenue for each component of other expenses.

	<b>Nine Months Ended September 30,</b>			
	<b>2006</b>	<b>Margin</b>	<b>2005</b>	<b>Margin</b>
Contract drilling.....	\$30,723,788	22%	\$27,349,389	22%
Oil and gas production.....	4,500,879	75	2,841,551	73
Gas transmission and compression.....	<u>1,706,948</u>	53	<u>880,611</u>	16
Total direct expenses.....	<u>36,931,615</u>	39	<u>31,071,551</u>	33
		<b>% Revenue</b>		<b>% Revenue</b>
Selling, general and administrative.....	10,274,430	17%	9,019,312	19%
Options, warrants and deferred compensation.....	1,211,701	2	853,988	2
Depreciation, depletion and amortization.....	5,437,808	9	3,039,366	7
Interest expense, net of interest income.....	2,700,323	4	1,258,687	3
Other, net.....	<u>(32,165)</u>	N/A	<u>(95,290)</u>	N/A
Total other expenses.....	<u>\$19,592,097</u>		<u>\$14,076,063</u>	

Contract drilling expenses reflect the substantial level and complexity of recent drilling activities, many of which were conducted in the current interim period under turnkey drilling contracts with drilling programs sponsored last year. On a period-over-period basis, these expenses remained at 78% of contract drilling revenues. Beginning this year, we have changed the structure of our new drilling programs from turnkey to cost-plus pricing, with a view to reducing our exposure to price volatility for drilling services, equipment and steel casing requirements. We began to realize slight improvements in our margins for this sector in the third quarter of 2006 as we completed the transition to our-plus pricing structure. We expect these margins to stabilize from ongoing cost-plus drilling program operations.

Production expenses for the current period were driven by our substantial growth in production volumes. The increase in our production expenses on a period-over-period basis was partially offset by cost savings realized from ownership of the NGAS Gathering system acquired in March 2006, eliminating our share of transmission fees for moving our Appalachian production for delivery through the system. See "Recent Initiatives." As a percentage of oil and gas production revenues, production expenses decreased to 25% in the first nine months of 2006 from 27% in the same period last year.

Gas transmission and compression expenses in the current interim period were 47% of associated revenues, compared to 84% in the first nine months of 2005. The improvement in margins for this part of our business reflects substantial revenue growth from third-party fees generated in the current period by ownership of the NGAS Gathering system. Our gas transmission and compression expenses do not reflect our acquisition costs for that system or capitalized costs of \$4,971,537 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 primarily reflect the timing and extent of our selling and promotional costs for sponsored drilling programs. On a period-over-period basis, they also reflect higher costs for supporting expanded operations as a whole, including additions to our staff and technology infrastructure as well as increased salary and other employee related expenses.

Non-cash charges for options, warrants and deferred compensation reflect the fair value method of accounting for employee stock options, which we adopted in 2004. 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 \$436,406 for deferred compensation cost.

Depreciation, depletion and amortization 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 these charges reflects substantial additions to our oil and gas properties, gas gathering systems and related equipment, including our acquisition of the NGAS Gathering transmission system \$18 million in March 2006.

Interest expense increased for the first nine months of 2006 from the addition of \$37 million in convertible debt at the end of 2005 and higher overall bank borrowings to support ongoing drilling and gas gathering initiatives. In addition to our drilling budget, these include our acquisition costs of \$18 million for the NGAS Gathering system, \$11.4 million for CBM assets in the Arkoma basin and capitalized costs of approximately \$5 million for extensions of our field-wide gas gathering systems and infrastructure during the first nine months of 2006. See “Liquidity and Capital Resources” below.

Income tax expense recognized in the current reported period represents future tax liability at the operating company level. We have no current tax liability due to the utilization of intangible drilling costs allocated from our active development drilling programs.

*Net Income and EPS.* We realized net income of \$1,484,649 for the nine months ended September 30, 2006, compared to \$388,611 in the same period last year, reflecting the foregoing factors. Basic EPS was \$0.07 based on 21,462,856 weighted average common shares outstanding in the current interim period, compared to \$0.02 based on 16,432,965 weighted average common shares outstanding in the first nine months of 2005. On a fully diluted basis, EPS for the nine months ended September 30, 2006 was \$0.06 on 22,981,498 weighted average common shares.

The results of operations for the three months and nine months ended September 30, 2006 are not necessarily indicative of results to be expected for the full year.

### ***Liquidity and Capital Resources***

*Liquidity.* Net cash of \$14,545,527 used in operating activities for the first nine months of 2006 primarily reflects a decrease of \$20,532,401 in customers’ drilling deposits from sponsored programs. During this period, we used \$43,214,373 in investing activities, most of which reflects net additions to our oil and gas properties and gathering systems, including our \$18 million acquisition of NGAS Gathering system assets in March 2006. See “Recent Initiatives.” These investments were funded in part with net cash of \$39,473,060 from financing activities. See “Capital Resources” below. As a result of these activities, net cash decreased from \$23,944,252 at December 31, 2005 to \$5,657,412 at September 30, 2006.

As of September 30, 2006, we had working capital of \$5,141,536. We are subject to wide fluctuations in our current assets and liabilities from the timing of customers’ drilling deposits and expenditures under drilling contracts with our sponsored programs. Since these fluctuations are normalized over relatively short time periods, we generally do not consider working capital to be a reliable measure of liquidity.

*Capital Resources.* Our business involves significant capital requirements. The rate of production from oil and gas properties generally 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. Our long term performance and profitability is dependent not only on developing existing oil and gas reserves, but also on our ability to find or acquire additional reserves on terms that are economically and operationally advantageous. To fund our ongoing reserve development and acquisition activities, we have relied on a combination of cash flows from operations, bank borrowings and private placements of our convertible notes and equity securities, as well as participation by outside investors in our sponsored drilling programs.

We issued several series of convertible notes in private placements to finance a substantial part of our drilling and acquisition activities. During 2005, all our outstanding prior series of notes were converted by their holders, either voluntarily or in response to our redemption calls, resulting in the issuance of 3,439,478 common shares.

In December 2005, we completed an institutional private placement of our 6% convertible notes due December 15, 2010 in the aggregate principal amount of \$37 million. The notes are convertible at the option of the holders at a conversion price of \$14.34 per share. During the third quarter of 2006, the warrants originally issued with the notes expired unexercised. At September 30, 2006, the notes were recorded at \$35,515,713, reflecting an allocation of \$2,394,913 at year end for the equity components of the notes, which was ratably accreted by \$344,680 in the first nine months of 2006, along with \$565,946 reallocated to debt upon expiration of the warrants.

The conversion price of the notes is subject to adjustments for certain dilutive issuances of common stock. The purchase agreement for the notes also provides the holders with certain participation rights in future financing transactions. If a holder elects to convert a note before the second anniversary of the issuance date, unless the prevailing market price of the common stock exceeds 160% of the conversion price, the holder will be entitled to a payment equal to the difference between two years' interest on the converted note and the interest already paid on the note, payable at our option in cash or in common shares. After that date, if the prevailing market price of the common stock exceeds 160% of the conversion price, we may redeem any unconverted notes at a redemption price equal to their principal amount plus accrued and unpaid interest. Any notes that are neither redeemed nor converted prior to maturity will be repayable in cash or in common shares. Any common shares issued for interest payments on converted notes or upon redemption at their maturity will generally be valued for that purpose at 92.5% of their prevailing market price.

In September 2006, we entered into a credit agreement with KeyBank National Association, as agent and primary lender. The credit agreement provides us with a senior secured revolving credit facility that replaces our prior credit facility with KeyBank, which had a scheduled maturity date of July 31, 2007 and a borrowing base of \$35 million. The new facility has a five-year maturity for revolving term loans and letters of credit in an aggregate amount up to \$125 million, with a current borrowing base of \$50 million. The facility is secured by liens on our interests in producing wells and field-wide gathering systems. Under the terms of the credit agreement, outstanding borrowings bear interest at fluctuating rates ranging from 1.5% to 2.5% above quoted LIBOR rates, depending on the amount of borrowing base utilization, plus commitment fees ranging from 0.375% to 0.5% of the unused borrowing base. As of September 30, 2006, our outstanding borrowings under the facility aggregated \$39 million, and the interest rate amounted to 8.5%.

Our ability to repay our bank debt and convertible notes 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 continue attracting investment capital to drilling programs. 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 reserves, cash flows from operations and available borrowing base under our credit facility to provide adequate working capital to meet our capital expenditure objectives through the end of 2006. To fully realize our financial goals for growth in revenues and reserves, we will continue to be dependent on the capital markets or other financing alternatives as well as continued participation by investors in future drilling programs.

### ***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 minimum annual commitments as of September 30, 2006 under these instruments.

<u>Year</u>	<u>Operating Leases</u>			<u>Other Commitments</u>	<u>Long Term Debt</u>
	<u>Equipment</u>	<u>Premises</u>	<u>Total</u>		
Remainder of 2006 .....	\$ 95,206	\$ 54,773	\$ 149,979	\$ 240,000 <sup>(1)</sup>	\$ 6,000
2007 .....	380,826	220,672	601,498	--	24,000
2008 .....	273,900	18,389	292,289	100,000 <sup>(2)</sup>	24,000
2009 .....	195,000	--	195,000	2,045,000 <sup>(2)</sup>	24,000
2010 and thereafter .....	<u>97,500</u>	<u>--</u>	<u>97,500</u>	<u>--</u>	<u>74,786,531</u>
Total .....	<u>\$1,042,432</u>	<u>\$ 293,834</u>	<u>\$1,336,266</u>	<u>\$2,385,000</u>	<u>\$74,864,531</u>

(1) Reflects obligations under a guaranty for a limited liability company in which we previously held a minority interest.

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

### ***Critical Accounting Policies and Estimates***

***General.*** The preparation of financial statements requires management to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses and related disclosure of contingent assets and liabilities. On an ongoing basis, management evaluates its estimates, including evaluations of any allowance for doubtful accounts and impairment of long-lived assets. Management bases its estimates on historical experience and on various other assumptions it believes to be reasonable under the circumstances. The results of these evaluations form a basis for making judgments 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 its estimates are reasonable and that actual results will not vary significantly from the estimated amounts.

***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.

***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.

### ***Forward Looking Statements and Risk Factors***

Some statements made by us in this report are prospective and constitute forward-looking statements within the meaning of the Private Litigation Reform Act of 1995. 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. The 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. Our annual report on Form 10-K for the year ended December 31, 2005 includes a discussion of these risk factors. There were no material changes in these risk factors during the interim periods covered by this report.

### **Item 3. Quantitative and Qualitative Disclosures about Market Risk**

Not applicable.

### **Item 4. Controls and Procedures**

Our management, with the participation or under the supervision of our Chief Executive Officer and Chief Financial Officer, is responsible for establishing and maintaining disclosure controls and procedures and internal control over financial reporting for the Company in accordance with the requirements of the Securities Exchange

Act of 1934. Our disclosure controls and procedures are intended to provide a framework for making sure that all information required to be disclosed in our current and periodic reports under the Exchange Act is processed and publicly reported by us within the prescribed time periods for our filing of those reports. Our internal controls over financial reporting are designed to ensure the reliability of our financial reporting and the preparation of our financial statements for external purposes in accordance with generally accepted accounting principles. They include policies and procedures for maintaining reasonably detailed records that accurately and fairly reflect all our business transactions and dispositions of assets, for ensuring that receipts and expenditures are made only in accordance with management authorizations and for preventing or timely detecting any unauthorized acquisition, use or disposition of our assets that could have a material effect on our financial statements.

Our Chief Executive Officer and Chief Financial Officer have evaluated the effectiveness of the design and operation of our disclosure controls and procedures and our internal control over financial reporting as of September 30, 2006. Based on their evaluation, they 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 period required under the Exchange Act. They have also concluded that our internal controls over financial reporting are effective to ensure the reliability of our financial reporting and the preparation of our publicly reported financial statements in accordance with generally accepted accounting principles. There were no changes in our controls or procedures during the three months or nine months ended September 30, 2006 that have materially affected or are reasonably likely to materially affect our internal control of financial reporting.

## **PART II. OTHER INFORMATION**

### **Item 6. Exhibits**

<b><i>Exhibit Number</i></b>	<b><i>Description of Exhibit</i></b>
3.1	Notice of Articles, certified on September 3, 2004 by the Registrar of Corporations under the British Columbia Business Corporations Act (incorporated by reference to Exhibit 3.1 to current report on Form 8-K [File No. 0-12185], filed September 29, 2004).
3.2	Alteration to Notice of Articles, certified on September 25, 2004 by the Registrar of Corporations under the British Columbia Business Corporations Act (incorporated by reference to Exhibit 3.2 to current report on Form 8-K [File No. 0-12185], filed September 29, 2004).
3.3	Articles dated September 25, 2004, as amended and restated for corporate transition under the British Columbia Business Corporations Act (incorporated by reference to Exhibit 3.3 to current report on Form 8-K [File No. 0-12185], filed September 29, 2004).
10.1	1997 Stock Option Plan (incorporated by reference to Exhibit 10[a] to annual report on Form 10-KSB [File No. 0-12185] for the year ended December 31, 2002).
10.2	2001 Stock Option Plan (incorporated by reference to Exhibit 10[b] to annual report on Form 10-KSB [File No. 0-12185] for the year ended December 31, 2002).
10.3	2003 Incentive Stock and Stock Option Plan (incorporated by reference to Exhibit 10.3 to quarterly report on Form 10-QSB [File No. 0-12185] for the quarter ended March 31, 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	Securities Purchase Agreement dated as of December 13, 2005 among NGAS Resources, Inc. and the investors named therein (incorporated by reference to Exhibit 10.1 to current report on Form 8-K [File No. 0-12185] dated December 14, 2005).

- 10.6 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).
- 10.7 Credit Agreement dated as of September 8, 2006 among NGAS Resources, Inc., Daugherty Petroleum, Inc. and KeyBank National Association, as agent for the lenders named therein (incorporated by reference to Exhibit 10.1 to current report on Form 8-K [File No. 0-12185] dated September 8, 2006).
- 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 March 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 March 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 March 31, 2004).
- 11.1 Computation of Earnings Per Share (included in Note 10 to the accompanying condensed 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, 2005).
- 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 9, 2006

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. (the "Company") on Form 10-Q for the quarter ended September 30, 2006, as filed with the Securities Exchange Commission on the date hereof under the Securities Exchange Act of 1934, as amended (the "Exchange Act"), the undersigned, William S. Daugherty, Chairman, Chief Executive Officer and President of NGAS Resources, Inc., 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 9, 2006

**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, 2006, as filed with the Securities Exchange Commission on the date hereof under the Securities Exchange Act of 1934, as amended (the "Exchange Act"), the undersigned, Michael P. Windisch, Chief Financial Officer of the NGAS Resources, Inc., 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 them 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 Reporting Period;
  - (b) designed such internal controls over financial reporting, or caused them 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 the Report our conclusions about the effectiveness of those disclosure controls and procedures, as of the end of the Reporting Period 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 9, 2006

**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. (the "Company") on Form 10-Q for the quarter ended September 30, 2006, as filed with the Securities Exchange Commission on the date hereof under the Securities Exchange Act of 1934, as amended (the "Exchange Act"), the undersigned, William S. Daugherty, Chairman, Chief Executive Officer and President of the Company, 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 the Company as of the date and for the periods reported therein.

*/s/ William S. Daugherty*

William S. Daugherty  
Chairman, Chief Executive Officer and President  
November 9, 2006

**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. (the "Company") on Form 10-Q for the quarter ended September 30, 2006, as filed with the Securities Exchange Commission on the date hereof under the Securities Exchange Act of 1934, as amended (the "Exchange Act"), the undersigned, Michael P. Windisch, Chief Financial Officer of the Company, 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 the Company as of the date and for the periods reported therein.

*/s/ Michael P. Windisch*

Michael P. Windisch  
Chief Financial Officer  
November 9, 2006