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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 June 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 August 1, 2006**  
**21,505,215**

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# NGAS RESOURCES, INC.

## INDEX

### Part I. Financial Information

	<u>Page</u>
<i>Item 1. Financial Statements:</i>	
Condensed Consolidated Balance Sheets – June 30, 2006 (unaudited) and December 31, 2005 .....	1
Condensed Consolidated Statement of Operations – Three months and six months ended June 30, 2006 and 2005 .....	2
Condensed Consolidated Statement of Cash Flows – Three months and six month ended June 30, 2006 and 2005 .....	3
Notes to Condensed Consolidated Financial Statements .....	4
<i>Item 2. Management’s Discussion and Analysis of Financial Condition and Results of Operations</i> .....	14
<i>Item 3. Quantitative and Qualitative Disclosures about Market Risk</i> .....	22
<i>Item 4. Controls and Procedures</i> .....	23

### PART II. OTHER INFORMATION

<i>Item 4. Submission of Matters to Vote of Security Holders</i> .....	23
<i>Item 6. Exhibits</i> .....	24

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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>June 30, 2006</b>	<b>December 31, 2005</b>
<b>ASSETS</b>		
Current assets:		
Cash .....	\$ 6,840,125	\$ 23,944,252
Accounts receivable.....	9,979,307	6,883,700
Prepaid expenses and other current assets .....	899,678	3,161,847
Loans to related parties.....	<u>7,058</u>	<u>26,235</u>
Total current assets .....	17,726,168	34,016,034
Bonds and deposits .....	443,695	432,695
Oil and gas properties .....	137,869,984	105,785,340
Property and equipment .....	3,121,779	2,934,169
Loans to related parties .....	261,138	264,377
Deferred financing costs .....	2,184,967	2,377,791
Other non-current assets.....	1,411,820	650,000
Goodwill .....	<u>313,177</u>	<u>313,177</u>
Total assets .....	<u>\$163,332,728</u>	<u>\$146,773,583</u>
<b>LIABILITIES</b>		
Current liabilities:		
Accounts payable .....	\$ 8,092,070	\$ 5,439,437
Accrued liabilities.....	6,639,610	5,788,554
Customers' drilling deposits.....	2,897,426	23,627,975
Long term debt, current portion.....	<u>24,000</u>	<u>24,000</u>
Total current liabilities.....	17,653,106	34,879,966
Future income taxes .....	5,903,878	3,881,755
Long term debt.....	64,177,497	34,947,905
Deferred compensation .....	<u>1,128,172</u>	<u>836,568</u>
Total liabilities.....	<u>88,862,653</u>	<u>74,546,194</u>
<b>SHAREHOLDERS' EQUITY</b>		
Common stock, no par value, 100,000,000 shares authorized, 21,472,942 shares issued (2005 – 21,357,628).....	82,949,847	82,371,189
21,100 shares held in treasury, at cost .....	(23,630)	(23,630)
Paid-in capital – options and warrants.....	3,235,570	2,743,806
Contributed surplus .....	1,572,500	1,748,926
9,185 shares to be issued .....	<u>45,925</u>	<u>45,925</u>
	87,780,212	86,886,216
Accumulated deficit .....	<u>(13,310,137)</u>	<u>(14,658,827)</u>
Total shareholders' equity .....	<u>74,470,075</u>	<u>72,227,389</u>
Total liabilities and shareholders' equity .....	<u>\$163,332,728</u>	<u>\$146,773,583</u>

*See accompanying notes.*

# NGAS RESOURCES, INC.

## CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS

(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2006	2005	2006	2005
<b>REVENUE</b>				
Contract drilling.....	\$ 11,029,274	\$ 7,639,000	\$ 31,440,774	\$ 24,316,000
Oil and gas production .....	5,935,783	3,507,703	12,139,967	6,383,491
Gas transmission and compression .....	1,374,585	289,016	2,078,156	746,474
Total revenue.....	<u>18,339,642</u>	<u>11,435,719</u>	<u>45,658,897</u>	<u>31,445,965</u>
<b>DIRECT EXPENSES</b>				
Contract drilling .....	7,840,559	6,618,260	24,543,489	18,988,065
Oil and gas production .....	1,529,940	890,694	2,983,408	1,649,515
Gas transmission and compression .....	541,869	235,084	1,174,298	627,868
Total direct expenses .....	<u>9,912,368</u>	<u>7,744,038</u>	<u>28,701,195</u>	<u>21,265,448</u>
<b>OTHER EXPENSES (INCOME)</b>				
Selling, general and administrative .....	3,164,516	2,511,910	7,638,908	6,018,735
Options, warrants and deferred compensation ..	419,787	239,090	848,534	491,698
Depreciation, depletion and amortization .....	1,964,578	1,001,533	3,502,490	2,048,088
Interest expense.....	1,089,070	555,001	1,689,453	1,063,754
Interest income.....	(101,524)	(48,386)	(219,884)	(86,126)
Other, net.....	86,440	(21,184)	127,388	(164,916)
Total other expenses.....	<u>6,622,867</u>	<u>4,237,964</u>	<u>13,586,889</u>	<u>9,371,233</u>
INCOME (LOSS) BEFORE INCOME TAXES .....	<u>1,804,407</u>	<u>(546,283)</u>	<u>3,370,813</u>	<u>809,284</u>
FUTURE INCOME TAX EXPENSE (BENEFIT) .....	<u>1,081,454</u>	<u>(10,631)</u>	<u>2,022,123</u>	<u>607,870</u>
NET INCOME (LOSS) .....	<u>\$ 722,953</u>	<u>\$ (535,652)</u>	<u>\$ 1,348,690</u>	<u>\$ 201,414</u>
<b>NET INCOME (LOSS) PER SHARE</b>				
Basic .....	<u>\$ 0.03</u>	<u>\$ (0.03)</u>	<u>\$ 0.06</u>	<u>\$ 0.01</u>
Diluted .....	<u>\$ 0.03</u>	<u>\$ (0.03)</u>	<u>\$ 0.06</u>	<u>\$ 0.01</u>
<b>WEIGHTED AVERAGE COMMON SHARES OUTSTANDING:</b>				
Basic.....	<u>21,456,828</u>	<u>16,005,158</u>	<u>21,417,395</u>	<u>15,848,386</u>
Diluted .....	<u>22,919,707</u>	<u>16,005,158</u>	<u>23,072,192</u>	<u>16,749,736</u>

*See accompanying notes.*

# NGAS RESOURCES, INC.

## CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2006	2005	2006	2005
<b>OPERATING ACTIVITIES</b>				
Net income (loss) .....	\$ 722,953	\$ (535,652)	\$ 1,348,690	\$ 201,414
Adjustments to reconcile net income to net cash provided by (used in) operating activities:				
Incentive bonus paid in common shares .....	--	--	291,032	217,026
Compensation from options and warrants .....	419,787	239,090	848,534	491,698
Contract settlement paid in common shares .....	--	(4,425)	--	(4,425)
Depreciation, depletion and amortization .....	1,964,578	1,001,533	3,502,490	2,048,088
Write-down of investment .....	--	55,454	--	55,454
Gain on sale of assets .....	4,015	--	22,973	(12,568)
Future income taxes (benefit) .....	1,081,454	(10,631)	2,022,123	607,870
Changes in assets and liabilities				
Accounts receivable .....	(2,897,966)	(1,670,147)	(3,095,607)	(2,195,382)
Prepaid expenses and other current assets ..	653,388	(937,893)	2,262,169	(934,913)
Other non-current assets .....	62,124	--	(761,820)	--
Accounts payable .....	1,118,653	(276,962)	2,652,633	981,482
Accrued liabilities .....	(1,953,700)	(138,397)	851,056	2,229,121
Customers' drilling deposits .....	(4,901,949)	8,257,125	(20,730,549)	7,282,724
Net cash provided by (used in) operating activities	<u>(3,726,663)</u>	<u>5,979,095</u>	<u>(10,786,276)</u>	<u>10,967,589</u>
<b>INVESTING ACTIVITIES</b>				
Proceeds from sale of assets .....	4,443	--	4,443	273,600
Purchase of property and equipment .....	(164,950)	(684,001)	(489,692)	(729,103)
Increase in bonds and deposits .....	(10,000)	(161,650)	(11,000)	(247,045)
Additions to oil and gas properties, net .....	(9,523,333)	(6,651,534)	(35,044,644)	(13,903,954)
Net cash used in investing activities .....	<u>(9,693,840)</u>	<u>(7,497,185)</u>	<u>(35,540,893)</u>	<u>(14,606,502)</u>
<b>FINANCING ACTIVITIES</b>				
Decrease in loans to related parties .....	1,775	29,980	22,416	123,803
Proceeds from issuance of common shares .....	119,570	245,860	287,626	1,494,636
Payments of deferred financing costs .....	--	--	(75,000)	(451,496)
Proceeds from issuance of long term debt .....	11,021,067	--	29,000,000	6,168,696
Payments of long term debt .....	(6,000)	(14,338)	(12,000)	(99,667)
Net cash provided by financing activities .....	<u>11,136,412</u>	<u>261,502</u>	<u>29,223,042</u>	<u>7,235,972</u>
Change in cash .....	(2,284,091)	(1,256,588)	(17,104,127)	3,597,059
Cash, beginning of period .....	9,124,216	16,703,019	23,944,252	11,849,372
Cash, end of period .....	<u>\$ 6,840,125</u>	<u>\$15,446,431</u>	<u>\$ 6,840,125</u>	<u>\$15,446,431</u>
<b>SUPPLEMENTAL DISCLOSURE</b>				
Interest paid .....	\$ 1,126,537	\$ 582,097	\$ 1,793,203	\$ 1,107,061
Income taxes paid .....	--	130,000	--	130,000
<b>SUPPLEMENTAL SCHEDULE OF NONCASH INVESTING AND FINANCING ACTIVITIES</b>				
Common shares issued upon conversion of notes ...	--	535,464	--	620,464

*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., 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 June 30, 2006 and results of operations and cash flows for the three months and six months ended June 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 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.

	<u>June 30, 2006</u>			<u>December 31,</u>
	<u>Cost</u>	<u>Accumulated DD&amp;A</u>	<u>Net</u>	<u>2005 Net</u>
Proved oil and gas properties.....	\$104,231,397	\$ (9,531,254)	\$ 94,700,143	\$ 83,567,982
Unproved oil and gas properties.....	3,045,144	--	3,045,144	2,434,814
Gathering lines and well equipment .....	41,765,806	(1,641,109)	40,124,697	19,782,544
Total oil and gas properties.....	<u>\$149,042,347</u>	<u>\$(11,172,363)</u>	<u>\$137,869,984</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 June 30, 2006 and December 31, 2005.

	<u>June 30, 2006</u>			<u>December 31, 2005</u>
	<u>Cost</u>	<u>Accumulated Depreciation</u>	<u>Net</u>	<u>Net</u>
Land.....	\$ 12,908	\$ --	\$ 12,908	\$ 12,908
Building improvements .....	48,350	(7,768)	40,582	29,777
Machinery and equipment .....	2,458,404	(653,771)	1,804,633	1,833,591
Office furniture and fixtures .....	122,459	(41,907)	80,552	50,830
Computer and office equipment .....	516,572	(260,502)	256,070	271,420
Vehicles .....	<u>1,376,367</u>	<u>(449,333)</u>	<u>927,034</u>	<u>735,643</u>
Total property and equipment.....	<u>\$4,535,060</u>	<u>\$(1,413,281)</u>	<u>\$3,121,779</u>	<u>\$2,934,169</u>

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

Financing costs for our convertible note private placements and secured bank loans are initially capitalized and amortized at rates based on the stated terms of the underlying debt instruments. 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 outstanding notes and bank loans aggregated \$2,184,967 at June 30, 2006 and \$2,377,791 at December 31, 2005, net of accumulated amortization totaling \$646,560 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 June 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 66.7%. 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 \$2,897,426 at June 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 and related common stock purchase warrants, all of which remained outstanding at June 30, 2006, with a conversion price of \$14.34 and an exercise price of \$13.04 per share. See Note 8 – Capital Stock.

The conversion price of the notes and exercise price of the warrants are 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.* We maintain a credit facility with KeyBank NA with a scheduled maturity date of July 31, 2007. The facility was expanded in the first quarter of 2006 to increase the maximum credit and borrowing base to \$75 million and \$35 million, respectively, and to reduce the interest rate for borrowings under the facility from 1% to 0.875% above the bank's prime rate, amounting to 9.125% at June 30, 2006. As of that date, our outstanding borrowings under the facility aggregated \$29 million. The facility is secured by liens on all corporate assets, including a first mortgage on oil and gas interests and pipelines, as well as an assignment of major production and transportation contracts.

(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 \$354,818 at June 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 June 30, 2006 and December 31, 2005 and the principal payments due each year through 2010 and thereafter.

	<u>Principal Amount Outstanding</u>	
	<u>June 30, 2006</u>	<u>December 31, 2005</u>
Total long term debt (including current portion) <sup>(1)</sup> .....	\$ 64,201,497	\$ 34,971,905
Less current portion .....	<u>24,000</u>	<u>24,000</u>
Total long term debt <sup>(1)</sup> .....	<u>\$ 64,177,497</u>	<u>\$ 34,947,905</u>
 <b><u>Maturities of Debt</u></b>		
Remainder of 2006 .....	\$ 12,000	
2007 .....	29,024,000	
2008 .....	24,000	
2009 .....	24,000	
2010 and thereafter .....	35,117,497	

(1) Reflects allocations of \$2,153,321 at June 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 June 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 .....	15,000	90,300
Balance, December 31, 2005 .....	21,357,628	82,371,189
Issued to employees as incentive bonus .....	38,315	291,032
Issued upon exercise of stock options and warrants .....	76,999	287,626
Balance, June 30, 2006 .....	<u>21,472,942</u>	<u>\$ 82,949,847</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 .....		556,930
Accreted <sup>(1)</sup> .....		<u>(65,166)</u>
Balance, June 30, 2006 .....		<u>\$ 3,235,570</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>(176,426)</u>
Balance, June 30, 2006 .....		<u>\$ 1,572,500</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, June 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 six months of 2006, stock awards and option grants were made under the third plan for a total of 834,415 shares and 38,315 shares, respectively. The following table shows transactions in stock options during 2005 and the first six 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 .....	--	146,250	4.03
Exercised .....	<u>(10,000)</u>	<u>(10,000)</u>	4.03
Balance, June 30, 2006 .....	<u>2,975,000</u>	<u>707,500</u>	4.67

(1) Vesting in increments from July 1, 2006 through February 25, 2009.

At June 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 3.38 years. The following table provides additional information on the terms of stock options outstanding at June 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	1.51	\$ 1.02	145,000	\$ 1.02	
4.03 4.09	1,970,000	3.22	4.05	562,500	4.06	
6.02 7.04	<u>860,000</u>	4.05	6.71	--	--	
	<u>2,975,000</u>			<u>707,500</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 \$556,930 and \$273,622 in the six months ended June 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 June 30, 2006 ranged from \$1.75 to \$13.04 per share, and their weighted average remaining contractual life was 0.16 years. The following table shows transactions in stock options during 2005 and the first six 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 <sup>(1)</sup> .....	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 .....	<u>(66,999)</u>		3.69
Balance, June 30, 2006 .....	<u>1,247,384</u>	1,247,384	10.83

(1) Expiring August 11, 2006.

**Note 9. Income (Loss) Per Share**

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

	<b>Three Months Ended June 30,</b>		<b>Six Months Ended June 30,</b>	
	<b>2006</b>	<b>2005</b>	<b>2006</b>	<b>2005</b>
<b>Diluted EPS</b>				
<b>Numerator:</b>				
Net income (loss) as reported for basic EPS.....	\$ 722,953	\$ (535,652)	\$ 1,348,690	\$ 201,414
Adjustments to income for diluted EPS.....	--	--	--	--
Net income (loss) for diluted EPS.....	<u>\$ 722,953</u>	<u>\$ (535,652)</u>	<u>\$ 1,348,690</u>	<u>\$ 201,414</u>
<b>Denominator:</b>				
Weighted average shares for basic EPS.....	21,456,828	16,005,158	21,417,395	15,848,386
Effect of dilutive securities:				
Stock options.....	1,277,449	--	1,444,601	633,686
Warrants.....	185,430	--	210,196	267,664
Adjusted weighted average shares and assumed conversions for diluted EPS .....	<u>22,919,707</u>	<u>16,005,158</u>	<u>23,072,192</u>	<u>16,749,736</u>
Basic EPS.....	<u>\$ 0.03</u>	<u>\$ (0.03)</u>	<u>\$ 0.06</u>	<u>\$ 0.01</u>
Diluted EPS .....	<u>\$ 0.03</u>	<u>\$ (0.03)</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 June 30,</b>		<b>Six Months Ended June 30,</b>	
	<b>2006</b>	<b>2005</b>	<b>2006</b>	<b>2005</b>
<b>Revenue:</b>				
Oil and gas development .....	\$ 18,339,642	\$ 11,435,719	\$ 45,658,897	\$ 31,445,965
Corporate .....	--	--	--	--
Total .....	<u>18,339,642</u>	<u>11,435,719</u>	<u>45,658,897</u>	<u>31,445,965</u>
<b>DD&amp;A:</b>				
Oil and gas development .....	1,810,080	902,232	3,196,825	1,865,542
Corporate .....	154,498	99,301	305,665	182,546
Total .....	<u>1,964,578</u>	<u>1,001,533</u>	<u>3,502,490</u>	<u>2,048,088</u>
<b>Interest expense:</b>				
Oil and gas development .....	534,070	259,191	579,453	525,290
Corporate .....	555,000	295,810	1,110,000	538,464
Total .....	<u>1,089,070</u>	<u>555,001</u>	<u>1,689,453</u>	<u>1,063,754</u>
<b>Net income (loss):</b>				
Oil and gas development .....	1,561,882	6,591	3,032,535	1,155,926
Corporate .....	(838,929)	(542,243)	(1,683,845)	(954,512)
Total .....	<u>722,953</u>	<u>(535,652)</u>	<u>1,348,690</u>	<u>201,414</u>
<b>Capital expenditures:</b>				
Oil and gas development .....	9,647,046	7,164,534	35,411,913	14,450,781
Corporate .....	41,237	171,001	122,423	182,276
Total .....	<u>\$ 9,688,283</u>	<u>\$ 7,335,535</u>	<u>\$ 35,534,336</u>	<u>\$ 14,633,057</u>

	<u>June 30,</u> <u>2006</u>	<u>December 31,</u> <u>2005</u>
<b><u>Identifiable assets:</u></b>		
Oil and gas development .....	\$ 159,892,800	\$ 126,590,249
Corporate .....	<u>3,439,928</u>	<u>20,183,334</u>
Total .....	<u>\$ 163,332,728</u>	<u>\$ 146,773,583</u>

**Note 11. Commitments**

The following table shows our contractual obligations as of June 30, 2006 under leases for field equipment and instruments governing our other commercial commitments. Our lease rental expenses were \$697,231 for the six months ended June 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.....	\$ 299,959	\$ 240,000 <sup>(1)</sup>	\$ 539,959
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>\$1,486,246</u>	<u>\$2,385,000</u>	<u>\$3,871,246</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**

FIN No. 47. In June 2005, the Financial Accounting Standards Board (“FASB”) issued FASB Interpretation (“FIN”) No. 47, “Accounting for Conditional Asset Retirement Obligations,” to clarify when sufficient information would be available to reasonably estimate the timing and cost of performing a conditional asset retirement obligation. Our asset retirement obligations relate primarily to the abandonment of oil and gas wells, and our treatment of these obligations is consistent with FIN No. 47.

SFAS No. 19 and FSP No. 19-1. In April 2005, FASB Staff Position (“FSP”) No. 19.1 was issued to amend the guidance for suspended well costs in SFAS No. 19, “Financial Accounting and Reporting by Oil and Gas Producing Companies.” The FSP addresses circumstances that permit continued capitalization of exploratory drilling costs beyond one year. In general, the one-year limitation may be exceeded for an exploratory well only if sufficient reserves have been found to justify its completion and sufficient progress has been made in assessing the reserves as well as the economic and operating viability of the project. The FSP is effective for the first reporting period beginning after April 4, 2005. We have found proved reserves for all exploratory wells drilled during the periods presented in the condensed consolidated financial statements within one year after completion of drilling and therefore have not expensed any exploratory drilling costs for those wells.

SFAS No. 154. SFAS No. 154, “Accounting Changes and Error Corrections,” was issued in June 2005, effective for accounting changes and correction of errors made in fiscal years beginning after December 15, 2005. It generally requires retrospective application for voluntary changes in accounting principles as well as changes required by accounting pronouncements. We adopted SFAS No. 154 on January 1, 2005. In August 2005, we amended our annual report on Form 10-KSB for the year ended December 31, 2004 and our quarterly report on Form 10-Q for the quarter ended June 30, 2005 to reflect two adjustments to the consolidated financial statements included in the reports. In the consolidated statements of operations, we eliminated the line item for gross profit, and in the consolidated statements of cash flows, reported changes in subscriptions receivable during 2004 were

eliminated from operating activities and added to financing activities as proceeds from issuance of common stock during the year in proportion to the subscription amounts received.

EITF No. 04-5. In June 2005, the FASB ratified the EITF No. 04-5, “Determining Whether a General Partner, or the General Partners as a Group, Controls a Limited Partnership or Similar Entity When the Limited Partners Have Certain Rights.” It creates a presumption the general partner in a limited partnership controls the partnership and must consolidate the partnership on its financial statements, effective for reporting periods beginning after December 15, 2005. The presumption of control and consolidation may be overcome if the limited partners have substantive participating rights or have the ability to effectively liquidate the partnership. We have evaluated the applicability of this guidance to our sponsored drilling programs and do not believe it will have a material impact on our consolidated financial statements.

EITF No. 04-10. In June 2005, the FASB ratified Emerging Issues Task Force (“EITF”) Issue No. 04-10, “Determining Whether to Aggregate Operating Segments That Do Not Meet the Quantitative Thresholds.” The consensus is effective for fiscal years ending after September 15, 2005 and has not had a material effect on our presentation of reportable operating segments.

EITF No. 05-2. In June 2005, the FASB ratified EITF Issue No. 05-2, “The Meaning of Conventional Convertible Debt Instrument.” The consensus is to be applied prospectively for new instruments entered into or modified in periods beginning after June 29, 2005. We have a series of convertible notes issued after that date and have recorded the notes as conventional convertible debt under this EITF. If we were to modify these notes, an evaluation of the terms of the instruments would be required after the modification to determine if they would remain conventional convertible debt instruments.

FERC Pronouncement. In June 2005, the Federal Energy Regulatory Commission (“FERC”) issued an order, “Accounting for Pipeline Assessment Cost,” to be effective January 1, 2006. The order requires companies to expense certain assessment costs, even if they were historically capitalized. This has not had a material effect on our consolidated financial statements.

EITF No. 05-8. In September 2005, the FASB ratified EITF Issue No. 05-8, “Income Tax Consequences of Issuing Convertible Debt with a Beneficial Conversion Feature.” The consensus requires a portion of convertible debt proceeds reflecting the intrinsic value of the beneficial conversion feature to be allocated to equity and recognized as a discount on the debt. The debt discount is accreted from the issuance date to the scheduled maturity date. The consensus is to be applied retrospectively to instruments with a beneficial conversion feature for periods beginning after December 15, 2005. We have applied this EITF in accounting for our 6% convertible notes issued in December 2005.

FSP No. 123(R)-4. In February 2006, the FASB issued 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 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 effect 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 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 "Mcfce" 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 Bcfe, while increasing our revenue by 30% to \$62.2 million and our estimated proved reserves by 9.2 Bcfe or 14% for the year. These milestones were complemented by significant appreciation in our share value. 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. We drilled 155 gross (44.3040 net) wells through our drilling programs in 2005. During the first six months of 2006, we drilled an additional 128 gross (30.3779 net) wells. 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 59 wells in the first six 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 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 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. In the first quarter of 2006, we launched a drilling program 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 will participate in up to 12 horizontal wells planned for our CBM project in the Arkoma basin. During the balance of the year, we plan to sponsor a drilling program for at least 85 additional wells on our core Appalachian properties. We anticipate contributing total program capital up to 75% for Leatherwood development, 60% for 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 June 30, 2006, we had interests in a total of 943 wells, with an inventory of 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 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 porosity and 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 June 30, 2006, our gas gathering facilities spanned 368 miles, including 140 miles installed during 2005 and 57 miles in the first six months of 2006, in addition to 116 miles of the Stone Mountain open-access system acquired from Duke Energy Gas Services, LLC (“Duke Energy”). 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 Stone Mountain system. As of the date of this report, we have a total of 134 wells producing to sales in Leatherwood and an additional 48 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 part of the Stone Mountain transmission system from Duke Energy for \$18 million. The system spans 116 miles in southeastern Kentucky and southwestern Virginia. It ties into Duke Energy’s East Tennessee Natural Gas pipeline system, which connects major natural gas supply basins to growing markets in the eastern United States. The acquisition also includes five delivery measuring and regulation stations, four compression stations and a liquids extraction plant. We operated the Stone Mountain system for Duke Energy since October 2004 and have now dedicated most of our Appalachian production for delivery through the

system. Unlike the gathering facilities we construct for connecting new wells in our major fields, the acquired system is open access, and our acquisition includes existing contracts for moving third-party gas through the system. The current through-put of the system is 14,000 Mcf per day, two-thirds of which we own or control. As currently configured, the system has an estimated through-put capacity of 24,000 Mcf per day. With compression upgrades, we can substantially increase this through-put capacity. By acquiring this system, we enhanced both our deliverability from core properties and our competitive position in the region. Our ownership of this system should also generate approximately \$3 million in gas transmission and compression revenues and cost savings on an annualized basis.

***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 June 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.

### ***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. Historically, natural gas wells in this part of the Appalachian basin recover between 150 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. During 2005, we sponsored five separate drilling programs. We contributed 30% of total capital to our two largest programs, 40% to a specialized program for a mix a development and exploratory wells on prospects included in a prior acquisition,

20% to a specialized program for testing the New Albany shale formation in western Kentucky and 33% to a specialized program for CBM wells in the Oklahoma sector of the Arkoma basin. In the first six months of 2006, we sponsored two new initiatives 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 a \$23.5 million program for up to 12 horizontal wells planned for our CBM project in the Arkansas sector of the Arkoma basin. The Arkoma wells are being drilled by CDX using its patented horizontal drilling and completion technology for accelerated CBM recovery. See “Recent Initiatives.”

*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.

- Based on our 30% capital investment in our largest 2005 drilling programs, we control a drilling budget over three times greater than we could support on our own. This helps us compete for attractive properties by increasing our drilling commitments. It also leverages our buying power for drilling services and materials, contributing to lower overall development costs.
- Aggregating our capital with private investors in our drilling programs enables us to maintain a larger and more capable staff than we could otherwise support if we were operating solely for our own account.
- 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 drilling operations on our undeveloped prospects through specially tailored drilling programs and retaining larger ownership interests, 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 25.85% during the first six 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 plan to increase our ownership interest in new drilling programs for Leatherwood development.

*Drilling Results.* The following table shows the number of gross and net development and exploratory wells we drilled during 2005 and the first six 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 drilled through our drilling programs, without giving effect to any reversionary interest we may subsequently earn in those programs. All of the exploratory wells recorded in the first six months of 2006 were drilled for a specialized program structured 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
Six months ended June 30, 2006 .....	98	23.3459	--	30	7.0320	--
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 six months ended June 30, 2006 and 2005 and for the year ended December 31, 2005. We also had extracted liquids and condensates that contributed \$96,030 to our production revenues in the first half of 2006 and \$91,931 in 2005.

	<b>Six Months Ended</b>		<b>Year Ended</b>
	<b>June 30,</b>		<b>December 31,</b>
	<b>2006</b>	<b>2005</b>	<b>2005</b>
Production volumes:			
Oil (Bbl).....	18,463	15,442	39,959
Natural gas (Mcf).....	1,282,497	741,237	1,583,922
Equivalent (Mcf).....	1,393,273	833,889	1,823,673
Average sales price:			
Natural gas (per Mcf).....	\$ 8.56	\$ 7.63	\$ 9.02
Oil (per Bbl).....	58.05	44.37	48.36

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

*Revenues.* The following table shows the components of our revenues for the three months ended June 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>Three Months Ended June 30,</b>			
	<b>2006</b>	<b>% of</b>	<b>2005</b>	<b>%</b>
		<b>Revenue</b>		<b>Change</b>
Contract drilling.....	\$11,029,274	60%	\$ 7,639,000	44%
Oil and gas production.....	5,935,783	32	3,507,703	69
Gas transmission and compression.....	<u>1,374,585</u>	<u>8</u>	<u>289,016</u>	376
Total.....	<u>\$18,339,642</u>	<u>100%</u>	<u>\$11,435,719</u>	60

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 second quarter of 2006, we drilled 49 gross (11.7244 net) wells. Many of the wells were drilled under our turnkey contracts entered in 2005. The balance were drilled for our first two 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. The first of those programs began operations toward the end of the first quarter, and the second will not account for any contract drilling revenues until the third quarter of 2006. We plan to sponsor an additional program with our new cost-plus structure during the second half of the year for at least 85 wells, primarily in Leatherwood and a variety of prospects in our Straight Creek, Fonde, Amvest and Martin's Fork fields.

Our substantial growth in production revenues on a period-over-period basis reflects a 67% increase in production volumes to 729.1 Mmcf the second quarter of 2006, with a 2% decline in our average sales price of natural gas (before certain transportation charges) to \$7.84 per Mcf. Compared to the fourth quarter of 2005 and the first quarter of 2006, production revenues for the three months ended June 30, 2006 increased 43% and 10%, respectively. 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 30% 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 \$884,035 for moving third-party gas through our Stone Mountain 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 \$35,053 from gas utility sales in the second quarter of 2006.

*Expenses.* The following table shows the components of our direct and other expenses for the three months ended June 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 June 30,</b>			
	<b>2006</b>	<b>Margin</b>	<b>2005</b>	<b>Margin</b>
Contract drilling.....	\$ 7,840,559	29%	\$ 6,618,260	13%
Oil and gas production.....	1,529,940	74	890,694	75
Gas transmission and compression.....	541,869	61	235,084	19
Total direct expenses.....	<u>9,912,368</u>	46	<u>7,744,038</u>	32
		<b>% Revenue</b>		<b>% Revenue</b>
Selling, general and administrative.....	3,164,516	17%	2,511,910	22%
Options, warrants and deferred compensation.....	419,787	2	239,090	2
Depreciation, depletion and amortization.....	1,964,578	11	1,001,533	9
Interest expense, net of interest income.....	987,546	5	506,615	4
Other, net.....	86,440	--	(21,184)	N/A
Total other expenses.....	<u>\$ 6,622,867</u>		<u>\$ 4,237,964</u>	

Contract drilling expenses reflect the substantial level and complexity of recent drilling activities, some of which were conducted in the current interim period under turnkey drilling contracts with drilling programs sponsored last year. As a percentage of contract drilling revenues, these expenses decreased to 71% in the current quarter from 87% in the second quarter of 2005. 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.

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 Stone Mountain system acquired from Duke Energy 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 second quarter of 2006 were 39% of associated revenues, compared to 81% in the same quarter last year. The improvement in margins for this part of our business reflects the substantial revenue growth from third-party fees generated in the current quarter from our ownership of the Stone Mountain system. Our gas transmission and compression expenses do not reflect our acquisition costs for the Stone Mountain system or capitalized costs of \$1,689,973 for extensions of our 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 \$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 Stone Mountain transmission system from Duke Energy for \$18 million in March 2006.

Interest expense increased for the second quarter of 2006 from higher overall debt to support ongoing drilling and gas gathering initiatives. We also incurred higher variable rates for our bank debt in the current interim period. 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 \$722,953 in the second quarter of 2006, compared to a net loss of \$535,652 recognized in the same quarter last year, reflecting the foregoing factors. Basic earnings per share (“EPS”) was \$0.03 based on 21,456,828 weighted average common shares outstanding in the current interim period, compared to \$(0.03) based on 16,005,158 weighted average common shares outstanding in the second quarter of 2005. On a fully diluted basis, EPS for the current interim period was \$0.03 on 22,919,707 weighted average common shares.

**Results of Operations – Six Months Ended June 30, 2006 and 2005**

*Revenues.* The following table shows the components of our revenues for the six months ended June 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>Six Months Ended June 30,</b>			
	<b>2006</b>	<b>% of Revenue</b>	<b>2005</b>	<b>% Change</b>
Contract drilling.....	\$31,440,774	69%	\$24,316,000	29%
Oil and gas production.....	12,139,967	27	6,383,491	90
Gas transmission and compression.....	<u>2,078,156</u>	<u>4</u>	<u>746,474</u>	178
Total.....	<u>\$45,658,897</u>	<u>100%</u>	<u>\$31,445,965</u>	45

Our revenue mix for the six months ended June 30, 2006 reflects our strategy for transitioning to a production based business, with gas sales accounting for 27% of total revenues, compared to 20% 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.

During the first six months of 2006, we drilled 128 gross (30.3779 net) wells. Many of the wells were drilled under our turnkey contracts entered in 2005. We sponsored two 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 second program will not account for any contract drilling revenues until the third quarter of 2006. We plan to sponsor an additional program with our new cost-plus structure during the second half of the year for at least 85 wells, primarily in Leatherwood and a variety of prospects in our Straight Creek, Fonde, Amvest and Martin’s Fork fields.

Our growth in production revenues on a period-over-period basis reflects increases of 67% in production volumes to 1,393.3 Mmcf and 12% in our average sales price of natural gas (before certain transportation charges) to \$8.56 per Mcf in the first six months of 2006. Compared to the second half of 2005, production revenues for the six months ended June 30, 2006 increased 41%, with additional volumetric growth anticipated as new wells are brought on line throughout the year. Principal purchasers of our natural gas production are gas marketers and customers with transmission facilities near our producing properties. Approximately 30% 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 \$884,035 for moving third-party gas through our Stone Mountain 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 \$156,171 from gas utility sales in the first six months of 2006 and \$186,165 in the same period last year.

*Expenses.* The following table shows the components of our direct and other expenses for the six months ended June 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>Six Months Ended June 30,</b>			
	<b><u>2006</u></b>	<b><u>Margin</u></b>	<b><u>2005</u></b>	<b><u>Margin</u></b>
Contract drilling.....	\$24,543,489	22%	\$18,988,065	22%
Oil and gas production.....	2,983,408	75	1,649,515	74
Gas transmission and compression.....	<u>1,174,298</u>	43	<u>627,868</u>	16
Total direct expenses.....	<u>28,701,195</u>	37	<u>21,265,448</u>	32
		<b><u>% Revenue</u></b>		<b><u>% Revenue</u></b>
Selling, general and administrative.....	7,638,908	17%	6,018,735	19%
Options, warrants and deferred compensation.....	848,534	2	491,698	2
Depreciation, depletion and amortization.....	3,502,490	8	2,048,088	7
Interest expense, net of interest income.....	1,469,569	3	977,628	3
Other, net.....	<u>127,388</u>	--	<u>(164,916)</u>	N/A
Total other expenses.....	<u>\$13,586,889</u>		<u>\$9,371,233</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. As a percentage of contract drilling revenues, these expenses remained consistent at 78% in the first half of both 2006 and 2005. 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.

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 in the second quarter of 2006 from ownership of the Stone Mountain system acquired earlier in the year from Duke Energy, 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 slightly to 25% in the first six months of 2006 from 26% in the same period last year.

Gas transmission and compression expenses in the current interim period were 57% of associated revenues, compared to 84% in the first half of 2005. The improvement in margins for this part of our business reflects the substantial revenue growth from third-party fees generated in the current period by ownership of the Stone Mountain system. Our gas transmission and compression expenses do not reflect our acquisition costs for the Stone Mountain system or capitalized costs of \$2,754,569 for extensions of our 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 \$291,604 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 Stone Mountain transmission system from Duke Energy for \$18 million in March 2006.

Interest expense increased for the first six months of 2006 from higher overall debt to support ongoing drilling and gas gathering initiatives. We also incurred higher variable rates for our bank debt in the current interim period. 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 \$1,348,690 for the six months ended June 30, 2006, compared to \$201,414 in the same period last year, reflecting the foregoing factors. Basic earnings per share ("EPS") was \$0.06 based on 21,417,395 weighted average common shares outstanding in the current interim period, compared to \$0.01 based on 15,848,386 weighted average common shares outstanding in the first six months of 2005. On a fully diluted basis, EPS for the current interim period was \$0.06 on 23,072,192 weighted average common shares.

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

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

Liquidity. Net cash of \$10,786,276 used in operating activities for the first six months of 2006 primarily reflects a decrease of \$20,730,549 in customers' drilling deposits from sponsored programs. During this period, we used \$35,540,893 in investing activities, most of which reflects net additions to our oil and gas properties and gathering systems, including our \$18 million acquisition of Stone Mountain gathering system assets from Duke Energy. See "Recent Initiatives." These investments were funded in part with net cash of \$29,223,042 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 \$6,840,125 at June 30, 2006.

As of June 30, 2006, we had marginal working capital of \$73,062. 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. The low working capital position at the end of June 2006 is not expected to have an adverse effect on our financial condition or results of operations in future periods.

Capital Resources. Our business involves significant capital requirements. The rate of production from oil and gas properties 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. As part of the private placement, we also issued warrants entitling the holders to purchase up to 945,809 shares of our common stock prior to August 11, 2006 at an exercise price of \$13.04 per share. At June 30, 2006, the notes were recorded at \$34,846,679, reflecting an allocation of \$2,394,913 at year end for the equity components of the notes and related warrants, which was ratably accreted by \$241,592 in the first six months of 2006.

The conversion price of our convertible notes and exercise price of the warrants are 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.

The purchase agreement for the notes provides for us to use our best efforts to obtain shareholder approval for the issuance of the underlying common shares, which was obtained at our annual meeting on June 29, 2006. This had the effect of eliminating the ceiling under Nasdaq listing rules for private placements that could involve 20% or more of a listed company's shares outstanding at the time of the private placement as a result of anti-dilution adjustments, exercise of participation rights or payments permitted under the purchase agreement in common shares.

We maintain a credit facility with KeyBank NA with a scheduled maturity date of July 31, 2007. The facility was expanded in the first quarter of 2006 to increase the maximum credit and borrowing base to \$75 million and \$35 million, respectively, and to reduce the interest rate for borrowings under the facility from 1% to 0.875% above the bank's prime rate, amounting to 9.125% at June 30, 2006. As of that date, our outstanding borrowings under the facility aggregated \$29 million. The facility is secured by liens on all corporate assets, including a first mortgage on oil and gas interests and pipelines, as well as an assignment of major production and transportation contracts.

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 may 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 June 30, 2006 under these instruments.

<b><u>Year</u></b>	<b><u>Operating Leases</u></b>			<b><u>Other Commitments</u></b>	<b><u>Long Term Debt</u></b>
	<b><u>Equipment</u></b>	<b><u>Premises</u></b>	<b><u>Total</u></b>		
Remainder of 2006 .....	\$ 190,413	\$ 109,546	\$ 299,959	\$ 240,000 <sup>(1)</sup>	\$ 12,000
2007 .....	380,826	220,672	601,498	--	29,024,000
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>35,117,497</u>
Total .....	<u>\$1,137,639</u>	<u>\$ 348,607</u>	<u>\$1,486,246</u>	<u>\$2,385,000</u>	<u>\$64,201,497</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 June 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 six months ended June 30, 2006 that have materially affected or are reasonably likely to materially affect our internal control of financial reporting.

## PART II. OTHER INFORMATION

### Item 4. Submission of Matters to a Vote of Security Holders

We held our annual meeting of shareholders in June 2006. All of the incumbent directors were reelected. The number of votes cast for and against each nominee is set forth below.

<u>Nominee</u>	<u>Votes For</u>	<u>Votes Withheld</u>
William S. Daugherty.....	18,778,854	126,450
Charles L. Cotterell .....	18,730,543	174,661
James K. Klyman .....	18,737,406	167,898
Thomas F. Miller.....	18,745,104	160,200

Our shareholders also voted at the meeting to approve proposals to fix the size of our board of directors for the ensuing year at four members, ratify the board's appointment of Hall, Kistler & Company LLP as our auditors for 2006 and approve the issuance of common shares under our convertible notes and warrants issued in December 2005. The number of votes cast for and against each of these proposals is set forth below.

<u>Proposal</u>	<u>Votes For</u>	<u>Votes Against</u>	<u>Broker Nonvotes</u>
Fixing the size of the board of directors at four members .....	18,745,117	160,127	--
Ratification of the appointment of independent public accountants .....	6,284,985	413,268	12,207,052
Approval of common stock issuance under notes and warrants .....	18,717,835	187,469	--

## Item 6. Exhibits

<u>Exhibit Number</u>	<u>Description of Exhibit</u>
3.1	Notice of Articles, certified on June 3, 2004 by the Registrar of Corporations under the British Columbia Business Corporations Act (incorporated by reference to Exhibit 3.1 to current report on Form 8-K [File No. 0-12185], filed June 29, 2004).
3.2	Alteration to Notice of Articles, certified on June 25, 2004 by the Registrar of Corporations under the British Columbia Business Corporations Act (incorporated by reference to Exhibit 3.2 to current report on Form 8-K [File No. 0-12185], filed June 29, 2004).
3.3	Articles dated June 25, 2004, as amended and restated for corporate transition under the British Columbia Business Corporations Act (incorporated by reference to Exhibit 3.3 to current report on Form 8-K [File No. 0-12185], filed June 29, 2004).
10.1	1997 Stock Option Plan (incorporated by reference to Exhibit 10[a] to annual report on Form 10-KSB [File No. 0-12185] for the year ended December 31, 2002).
10.2	2001 Stock Option Plan (incorporated by reference to Exhibit 10[b] to annual report on Form 10-KSB [File No. 0-12185] for the year ended December 31, 2002).
10.3	2003 Incentive Stock and Stock Option Plan (incorporated by reference to Exhibit 10.3 to quarterly report on Form 10-QSB [File No. 0-12185] for the quarter ended 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	Form of common stock purchase warrant dated December 14, 2005 (incorporated by reference to Exhibit 10.3 to current report on Form 8-K [File No. 0-12185] dated December 14, 2005).
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 Rule 13a-14(a) under the Securities Exchange Act of 1934, as amended.
- 31.2 Certification of Chief Financial Officer pursuant to Rule 13a-14(a) under the Securities Exchange Act of 1934, as amended.
- 32.1 Certification of Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted under Section 906 of the Sarbanes-Oxley Act of 2002.
- 32.2 Certification of Chief Financial Officer pursuant to 18 U.S.C. Section 1350, 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: August 8, 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 June 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 Exchange Act Rule 13a-14(a) or 15d-14(a) 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  
August 8, 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 June 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  
August 8, 2006

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

In connection with the quarterly report of NGAS Resources, Inc. (the "Company") on Form 10-Q for the quarter ended June 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(a) under the Securities Exchange Act of 1934 and Section 1350 of Chapter 63 of Title 18 of the United States Code, 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  
August 8, 2006

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

In connection with the quarterly report of NGAS Resources, Inc. (the “Company”) on Form 10-Q for the quarter ended June 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(a) under the Securities Exchange Act of 1934 and Section 1350 of Chapter 63 of Title 18 of the United States Code, 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  
August 8, 2006