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

AMENDMENT NO. 1 TO
FORM 10-Q

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

TRANSITION REPORT UNDER SECTION 13 OR 15(d) OF EXCHANGE ACT

Commission File No. 0-12185

NGAS RESOURCES, INC.

(Exact name of registrant as specified in its charter)

Province of British Columbia

(State or other jurisdiction of
incorporation or organization)

Not Applicable

(I.R.S. Employer
Identification No.)

120 Prosperous Place, Suite 201
Lexington, Kentucky

(Address of principal executive offices)

40509-1844

(Zip Code)

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

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

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

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

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

Large accelerated filer

Non-accelerated filer

Accelerated filer

Smaller reporting company

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

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

Title of Class
Common Stock

Outstanding at August 4, 2009
27,004,361

NGAS RESOURCES, INC.

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ADDITIONAL INFORMATION

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

EXPLANATORY NOTE

This amended report (10-Q/A) modifies some of the disclosures in our quarterly report on Form 10-Q for the quarter ended June 30, 2009 (10-Q) in response to review comments by the staff of the SEC. The 10-Q/A restates Part I of the 10-Q in its entirety but does not change any disclosures except as noted below, and it does not update the 10-Q to reflect any other developments or events after the date of the original filing.

- *Condensed Consolidated Financial Statements* – The condensed consolidated financial statements have been restated to account for the embedded conversion feature of our 6% convertible notes as a derivative liability under ASC 815-40-15 (formerly EITF 07-5), which became effective as of January 1, 2009. The impact of the change in accounting principles is set forth in Note 2 – Restatement Adjustments.
 - *MD&A* – The recognition of non-cash interest expense for accretion of the debt discount and related adjustments from the change in accounting principles are reflected under the caption “Results of Operations.”
 - *Certifications* – The certifications in the exhibits to the 10-Q have been updated as the date of this 10-Q/A.
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NGAS RESOURCES, INC.

CONDENSED CONSOLIDATED BALANCE SHEETS

	June 30, 2009	December 31, 2008
ASSETS		
Current assets:	(Unaudited)	
Cash.....	\$ 7,642,019	\$ 981,899
Accounts receivable.....	5,684,160	10,450,173
Prepaid expenses and other current assets	515,848	540,253
Loans to related parties.....	<u>76,914</u>	<u>79,188</u>
Total current assets	13,918,941	12,051,513
Bonds and deposits.....	263,695	623,898
Oil and gas properties	179,603,725	229,218,344
Assets held for sale	47,216,714	—
Property and equipment	5,667,261	3,285,925
Loans to related parties	171,429	171,429
Deferred financing costs	1,645,985	1,689,580
Goodwill	<u>313,177</u>	<u>313,177</u>
Total assets	<u>\$248,800,927</u>	<u>\$247,353,866</u>
LIABILITIES		
Current liabilities:		
Accounts payable	\$ 5,237,137	\$ 12,362,092
Accrued liabilities.....	665,157	675,141
Deferred compensation.....	2,094,700	2,246,439
Customer drilling deposits.....	698,400	2,262,955
Long-term debt, current portion	<u>87,703</u>	<u>24,000</u>
Total current liabilities	8,783,097	17,570,627
Deferred compensation	344,013	—
Deferred income taxes	13,012,717	12,949,476
Long-term debt.....	112,878,664	109,270,818
Fair value of derivative financial instruments.....	5,513	—
Other long-term liabilities	<u>4,008,675</u>	<u>3,685,849</u>
Total liabilities.....	<u>139,032,679</u>	<u>143,476,770</u>
SHAREHOLDERS' EQUITY		
Capital stock		
<i>Authorized:</i>		
5,000,000 Preferred shares		
100,000,000 Common shares		
<i>Issued:</i>		
26,968,646 Common shares (2008 – 26,543,646)	110,988,162	110,626,912
21,100 Common shares held in treasury, at cost.....	(23,630)	(23,630)
Paid-in capital – options and warrants	4,204,791	3,774,600
<i>To be issued:</i>		
9,185 Common shares (2008 – 9,185)	<u>45,925</u>	<u>45,925</u>
	115,215,248	114,423,807
Deficit	<u>(5,447,000)</u>	<u>(10,546,711)</u>
Total shareholders' equity	<u>109,768,248</u>	<u>103,877,096</u>
Total liabilities and shareholders' equity	<u>\$248,800,927</u>	<u>\$247,353,866</u>

See accompanying notes.

NGAS RESOURCES, INC.

CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS

(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2009	2008	2009	2008
REVENUE				
Contract drilling.....	\$ 5,172,998	\$ 7,625,356	\$ 12,496,750	\$ 14,227,474
Oil and gas production	6,891,644	11,179,620	13,958,863	19,669,054
Gas transmission, compression and processing.....	<u>2,599,229</u>	<u>2,536,560</u>	<u>5,404,211</u>	<u>5,094,652</u>
Total revenue	<u>14,663,871</u>	<u>21,341,536</u>	<u>31,859,824</u>	<u>38,991,180</u>
DIRECT EXPENSES				
Contract drilling	3,873,266	5,756,997	9,414,692	10,876,846
Oil and gas production	2,614,094	3,107,095	4,939,059	5,872,050
Gas transmission, compression and processing.....	<u>1,025,408</u>	<u>957,548</u>	<u>1,994,325</u>	<u>2,047,794</u>
Total direct expenses	<u>7,512,768</u>	<u>9,821,640</u>	<u>16,348,076</u>	<u>18,796,690</u>
OTHER EXPENSES (INCOME)				
Selling, general and administrative	2,552,740	3,442,094	5,803,005	6,730,577
Options, warrants and deferred compensation ..	319,192	234,803	737,465	372,482
Depreciation, depletion and amortization	3,687,621	3,261,192	7,306,491	6,132,952
Bad debt expense	—	59,000	—	406,840
Interest expense.....	2,415,451	1,355,643	4,696,459	2,681,613
Interest income	(6,194)	(9,093)	(15,010)	(78,803)
Fair value (gain) loss on derivative financial instruments.....	4,995	—	(9,324)	—
Other, net.....	<u>216,377</u>	<u>34,632</u>	<u>295,918</u>	<u>28,355</u>
Total other expenses	<u>9,190,182</u>	<u>8,378,271</u>	<u>18,815,004</u>	<u>16,274,016</u>
INCOME (LOSS) BEFORE INCOME TAXES	(2,039,079)	3,141,625	(3,303,256)	3,920,474
INCOME TAX EXPENSE (BENEFIT).....	<u>(103,921)</u>	<u>1,620,363</u>	<u>63,241</u>	<u>2,236,023</u>
NET INCOME (LOSS)	<u>\$ (1,935,158)</u>	<u>\$ 1,521,262</u>	<u>\$ (3,366,497)</u>	<u>\$ 1,684,451</u>
NET INCOME (LOSS) PER SHARE				
Basic	<u>\$ (0.07)</u>	<u>\$ 0.06</u>	<u>\$ (0.13)</u>	<u>\$ 0.06</u>
Diluted	<u>\$ (0.07)</u>	<u>\$ 0.06</u>	<u>\$ (0.13)</u>	<u>\$ 0.06</u>
WEIGHTED AVERAGE COMMON SHARES OUTSTANDING:				
Basic.....	<u>26,968,646</u>	<u>26,346,506</u>	<u>26,820,718</u>	<u>26,291,159</u>
Diluted	<u>26,968,646</u>	<u>27,344,529</u>	<u>26,820,718</u>	<u>27,015,161</u>

See accompanying notes.

NGAS RESOURCES, INC.

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

	(Unaudited)			
	Three Months Ended June 30,		Six Months Ended June 30,	
	<u>2009</u>	<u>2008</u>	<u>2009</u>	<u>2008</u>
OPERATING ACTIVITIES				
Net income (loss)	\$(1,935,158)	\$ 1,521,262	\$(3,366,497)	\$ 1,684,451
Adjustments to reconcile net income to net cash provided by operating activities:				
Incentive bonus paid in common shares	—	—	361,250	31,570
Options, warrants and deferred compensation ..	319,192	234,803	737,465	372,482
Depreciation, depletion and amortization	3,687,621	3,261,192	7,306,491	6,132,952
Bad debt expense	—	59,000	—	406,840
Gain (loss) on sale of assets	(3,620)	981	(12,905)	(355)
Fair value (gain) loss on derivative financial instruments	4,995	—	(9,324)	—
Accretion of debt discount	955,627	—	1,864,594	—
Deferred income taxes (benefit)	(103,921)	1,620,363	63,241	2,236,023
Changes in assets and liabilities				
Accounts receivable	74,059	(2,987,214)	4,766,013	(4,143,320)
Prepaid expenses and other current assets ..	94,002	574,348	24,405	117,614
Other non-current assets	—	—	—	3,242,790
Accounts payable	(28,706)	(1,633,082)	(7,124,955)	704,684
Accrued liabilities	23,395	78,814	(9,984)	207,618
Deferred compensation	(115,000)	—	(115,000)	—
Customers' drilling deposits	(895,848)	(1,396,787)	(1,564,555)	(1,227,502)
Other long-term liabilities	162,769	—	322,826	—
Net cash provided by operating activities	<u>2,239,407</u>	<u>1,333,680</u>	<u>3,243,065</u>	<u>9,765,847</u>
INVESTING ACTIVITIES				
Proceeds from sale of assets	34,337	26,500	54,033	38,700
Purchase of property and equipment	(2,458,544)	(149,214)	(2,487,800)	(304,501)
Change in bonds and deposits	224,203	39,500	10,203	(35,500)
Additions to oil and gas properties, net	<u>1,931,517</u>	<u>(13,228,191)</u>	<u>(4,077,095)</u>	<u>(26,325,157)</u>
Net cash used in investing activities	<u>(268,487)</u>	<u>(13,311,405)</u>	<u>(6,500,659)</u>	<u>(26,626,458)</u>
FINANCING ACTIVITIES				
Decrease in loans to related parties	560	739	2,274	2,677
Proceeds from issuance of common shares	—	1,006,806	—	1,108,806
Payments of deferred financing costs	(371,527)	(29,250)	(372,560)	(143,543)
Proceeds from issuance of long-term debt	4,800,000	11,000,000	10,300,000	16,740,000
Payments of long-term debt	<u>(6,000)</u>	<u>(6,000)</u>	<u>(12,000)</u>	<u>(2,026,175)</u>
Net cash provided by financing activities	<u>4,423,033</u>	<u>11,972,295</u>	<u>9,917,714</u>	<u>15,681,765</u>
Change in cash	6,393,953	(5,430)	6,660,120	(1,178,846)
Cash, beginning of period	<u>1,248,066</u>	<u>1,643,262</u>	<u>981,899</u>	<u>2,816,678</u>
Cash, end of period	<u>\$ 7,642,019</u>	<u>\$ 1,637,832</u>	<u>\$ 7,642,019</u>	<u>\$ 1,637,832</u>
SUPPLEMENTAL DISCLOSURE				
Interest paid	\$ 1,450,714	\$ 1,353,635	\$ 2,822,194	\$ 2,681,318
Income taxes paid	—	—	—	—

See accompanying notes.

NGAS RESOURCES, INC.

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

(Unaudited)

Note 1. Summary of Significant Accounting Policies

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

(b) Basis of Presentation. The accompanying condensed consolidated financial statements include the accounts of NGAS, our wholly owned subsidiary, Daugherty Petroleum, Inc. (DPI), and its wholly owned subsidiaries. The condensed consolidated financial statements also reflect DPI's interests in a total of 39 drilling partnerships sponsored to participate in many of our drilling initiatives. We account for those interests using the proportionate consolidation method, with all material inter-company accounts and transactions eliminated on consolidation. References to the *company, we, our* or *us* include DPI, its subsidiaries and interests in sponsored drilling partnerships. These interim consolidated financial statements are unaudited and have been restated for the three months and six months ended June 30, 2009 to reflect the adoption of Accounting Standards Codification (ASC) Topic 815-40-15, *Contracts in Entity's Own Equity* (formerly EITF 07-5), which became effective as of January 1, 2009. See Note 2 – Restatement Adjustments. In the opinion of our management, the accompanying condensed consolidated financial statements reflect all normal recurring adjustments that, in the opinion of our management, are necessary to fairly present our financial position at June 30, 2009 and results of operations and cash flows for the three months and six months ended June 30, 2009 and 2008.

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

Note 2. Restatement Adjustments

(a) Change in Accounting Principle. Effective as of January 1, 2009, we adopted the revised guidance for equity-linked financial instruments now codified in ASC 815-40-15, which requires the embedded conversion feature of our 6% convertible notes to be bifurcated and treated as a derivative liability based on its fair value as a stand-alone instrument. The notes were issued in December 2005 in the principal amount of \$37 million. See Note 8 – Long-Term Debt. Under the revised guidance, the notes are no longer considered to be linked to our own stock due to the weighted average antidilution provisions in their embedded conversion feature. As a result, the notes no longer qualify for the scope exception from derivative fair value accounting under ASC 815-15, *Derivatives and Hedging – Embedded Derivatives* (formerly contained in SFAS 133).

(b) Cumulative Effect Adjustments. The transition provisions of ASC 815-40-15 require cumulative effect adjustments as of January 1, 2009 to reflect the amounts that would have been recognized if derivative fair value accounting had been applied from the original issuance date of an equity-linked financial instrument through the implementation date of the revised guidance. Our fair value analysis of the notes reflects an initial derivative liability of \$16,575,445 for their embedded conversion feature, primarily reflecting their five-year maturity and 10% conversion premium at issuance. From the note issuance date through the end of 2008, we would have recorded fair value gains on derivative financial instruments of \$16,560,608, offset by non-cash interest expenses totaling \$8,094,400, reflecting accretion of the debt discount under the effective interest method. The following table shows the cumulative effect adjustment to retained deficit at January 1, 2009.

<u>Cumulative Effect Adjustment:</u>	<u>Retained Deficit</u>
As previously reported, December, 31, 2008.....	\$ (10,546,711)
Cumulative effect adjustment.....	<u>8,466,208</u>
As adjusted, January 1, 2009	<u>\$ (2,080,503)</u>

(c) *Impact on Interim Financial Statements.* As restated at June 30, 2009, the carrying amount of our convertible notes has been recorded at \$30,383,549. This reflects the unaccreted debt discount to their face amount of \$37 million. In addition, a derivative liability has been established at \$5,513, representing the fair value of the embedded conversion feature at the balance sheet date. The following table shows the adjustments on restatement of the condensed consolidated statements of operations previously reported for the three months and six months ended June 30, 2009. The adjustments to interest expense reflect accretion of the debt discount under the effective interest method. The fair value gains on derivative financial instruments reflect mark-to market changes in the fair value of the embedded derivative.

<u>Three Months Ended June 30, 2009:</u>	<u>As Previously Reported</u>	<u>Restatement Adjustments</u>	<u>As Restated</u>
Total revenue	\$ 14,663,871	\$ —	\$ 14,663,871
Total direct expenses	7,512,768	—	7,512,768
Other expenses (income)			
Selling, general and administrative.....	2,552,740	—	2,552,740
Options, warrants and deferred compensation	319,192	—	319,192
Depreciation, depletion and amortization	3,687,621	—	3,687,621
Interest expense	1,459,824	955,627	2,415,451
Interest income.....	(6,194)	—	(6,194)
Fair value loss on derivative financial instruments.....	—	4,995	4,995
Other, net	<u>216,377</u>	<u>—</u>	<u>216,377</u>
Total other expenses.....	<u>8,229,560</u>	<u>960,622</u>	<u>9,190,182</u>
Loss before income taxes	(1,078,457)	(960,622)	(2,039,079)
Income tax benefit	<u>(103,921)</u>	<u>—</u>	<u>(103,921)</u>
Net loss	<u>\$ (974,536)</u>	<u>\$ (960,622)</u>	<u>\$ (1,935,158)</u>
EPS - basic and diluted.....	<u>\$ (0.04)</u>	<u>\$ (0.03)</u>	<u>(0.07)</u>
 <u>Six Months Ended June 30, 2009:</u>			
Total revenue	\$ 31,859,824	\$ —	\$ 31,859,824
Total direct expenses	16,348,076	—	16,348,076
Other expenses (income)			
Selling, general and administrative.....	5,803,005	—	5,803,005
Options, warrants and deferred compensation	737,465	—	737,465
Depreciation, depletion and amortization	7,306,491	—	7,306,491
Interest expense	2,831,865	1,864,594	4,696,459
Interest income.....	(15,010)	—	(15,010)
Fair value gain on derivative financial instruments	—	(9,324)	(9,324)
Other, net	<u>295,918</u>	<u>—</u>	<u>295,918</u>
Total other expenses.....	<u>16,959,734</u>	<u>1,855,270</u>	<u>18,815,004</u>
Loss before income taxes	(1,477,986)	(1,855,270)	(3,303,256)
Income tax expense	<u>63,241</u>	<u>—</u>	<u>571,357</u>
Net loss	<u>\$ (1,052,342)</u>	<u>\$ (1,855,270)</u>	<u>\$ (3,366,497)</u>
EPS – basic and diluted	<u>\$ (0.06)</u>	<u>\$ (0.07)</u>	<u>\$ (0.13)</u>

Note 3. Oil and Gas Properties

(a) *Sale of 50% Undivided Interest in Appalachian Gas Gathering Facilities.* On May 11, 2009, DPI and its gas gathering subsidiaries, NGAS Gathering, LLC and NGAS Gathering II, LLC (*NG II*), entered into an Asset Purchase Agreement (*APA*) with Seminole Gas Company, L.L.C. (*Seminole*) for the sale of a 50% undivided interest in our Appalachian gas gathering and midstream facilities (*Gathering System*) at a purchase price of \$28 million. The closing under the *APA* occurred on July 15, 2009. At that time, we transferred all of our retained interests in the *Gathering System* to *NG II* and entered into various joint ownership, gas marketing and gas sales arrangements with *Seminole* and its parent company, *Seminole Energy Services, LLC (Seminole Energy)*. Under these arrangements, we retained operating rights for the *Gathering System* and firm capacity rights for daily delivery of 30,000 Mcf of controlled gas through the system. As part of the transactions covered by the *APA*, we also granted *Seminole Energy* a six-month option to purchase our retained 50% interest in the *Gathering System* for \$22 million, payable \$7.5 million at closing and the balance over 30 months under a promissory note bearing interest at 8% per annum. We have the right to require *Seminole Energy* to exercise its purchase option if we complete an equity offering for at least \$5 million within the six-month option period.

(b) *Capitalized Costs and DD&A.* All of our oil and gas development and producing activities are conducted within the continental United States. Capitalized costs and accumulated depreciation, depletion and amortization (*DD&A*) for our oil and gas properties, gathering facilities and well equipment as of June 30, 2009 and December 31, 2008 are summarized below. The oil and gas properties shown in the table at June 30, 2009 do not include either the 50% undivided interest in the *Gathering System* sold to *Seminole* in July 2009 or our retained interest in the *Gathering System* covered by the *Seminole Option*.

	<u>June 30,</u> <u>2009⁽¹⁾</u>	<u>December 31,</u> <u>2008</u>
Proved oil and gas properties.....	\$ 194,933,880	\$ 192,186,676
Unproved oil and gas properties	5,031,686	5,065,835
Gathering facilities and well equipment	<u>16,162,264</u>	<u>67,326,445</u>
	216,127,830	264,578,956
Accumulated DD&A	<u>(36,524,105)</u>	<u>(35,360,612)</u>
Net oil and gas properties and equipment	<u>\$ 179,603,725</u>	<u>\$ 229,218,344</u>

(1) Excludes capitalized costs totaling \$47,216,714 for *Gathering System* assets held for sale, net of accumulated depreciation totaling \$5,311,507.

(c) *Suspended Well Costs.* We had no suspended exploratory wells costs that were required to be expensed during 2008 or the first six months of 2009 based on the criteria of FSP No. 19-1, *Accounting for Suspended Well Costs*. As of June 30, 2009, we had no wells for which exploratory wells costs had been capitalized for a period of greater than one year after completion of drilling.

Note 4. Property and Equipment

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

	<u>June 30,</u> <u>2009</u>	<u>December 31,</u> <u>2008</u>
Land.....	\$ 12,908	\$ 12,908
Building improvements	64,265	64,265
Machinery and equipment	6,164,986	3,333,981
Office furniture and fixtures	175,862	175,862
Computer and office equipment	669,465	670,349
Vehicles	<u>1,790,323</u>	<u>1,951,279</u>
	8,877,809	6,208,644
Accumulated depreciation	<u>(3,210,548)</u>	<u>(2,922,719)</u>
Net other property and equipment.....	<u>\$ 5,667,261</u>	<u>\$ 3,285,925</u>

Note 5. Deferred Financing Costs

Financing costs for our convertible notes and secured credit facility are initially capitalized and amortized at rates based on the terms of the underlying debt instruments. See Note 8 – Long-Term Debt. Upon conversion of convertible notes, the principal amount converted is added to equity, net of a proportionate amount of the original financing costs. Unamortized deferred financing costs for our outstanding notes and credit facility aggregated \$1,645,985 at June 30, 2009 and \$1,689,580 at December 31, 2008.

Note 6. Goodwill

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

Note 7. Customer Drilling Deposits

Net proceeds received under drilling contracts with sponsored partnerships and joint ventures are recorded as customer drilling deposits at the time of receipt. We recognize revenues from drilling operations on the completed contract method as the wells are drilled, rather than when funds are received. We had customer drilling deposits of \$698,400 at June 30, 2009 and \$2,262,955 at December 31, 2008, representing unapplied drilling contract payments for wells that were not yet drilled as of the balance sheet date.

Note 8. Long-Term Debt

(a) Convertible Notes. We have an outstanding series of 6% convertible notes due December 15, 2010 in the aggregate principal amount of \$37 million. The notes are convertible into our common shares at a conversion price of \$12.94. Upon any event of default under the notes or any change of control, we may be required to redeem the notes at a default rate equal to 125% of their principal amount or at a change of control rate equal to the greater of 110% of their principal amount or the consideration that would be received by the holders for the underlying shares in the change of control transaction. Any notes that are neither redeemed nor converted prior to maturity will be repayable in cash or in common shares, valued for that purpose at 92.5% of their prevailing market price.

(b) Credit Facility. We have a senior secured revolving credit facility maintained by DPI under a credit agreement with KeyBank National Association, as administrative agent for the lenders. The facility provides for revolving term loans and letters of credit in an aggregate amount up to \$125 million, with a borrowing base of \$80 million at December 31, 2008 and June 30, 2009. As of June 30, 2009, the facility was fully drawn, with an interest rate amounting to 5.5%. The facility is secured by liens on our proved oil and gas properties. Obligations under the facility have a scheduled maturity in September 2011 and are guaranteed by NGAS. On June 2, 2009, we entered into an amendment to the credit agreement to establish a semi-annual redetermination of our borrowing base and provide various modifications to permit the sale of a 50% undivided interest in our Gathering System to Seminole under the APA. The amendment provides for the following modifications to the credit agreement, effective as of July 15, 2009 upon the closing of the sale under the APA:

- Redetermination of the borrowing base to \$65 million, with an additional \$10 million reduction upon release of our Gathering System assets from the collateral package under the credit agreement;
- Change in the maximum interest rate for borrowings under the credit agreement to 2.25% above the administrative agent's prime rate;
- Waiver of current ratio financial covenant under the credit agreement until September 30, 2009, and
- Adjustments to our other financial covenants under the credit agreement through December 31, 2010.

Under the terms of the credit agreement amendment, our proceeds of \$28 million from the sale of a 50% undivided interest in the Gathering System were applied to reduce our outstanding borrowings under the credit facility to \$52 million. The credit agreement amendment also provides for the further repayment of our outstanding borrowings with the additional proceeds from any exercise of the six-month purchase option granted to Seminole Energy under the APA. The total purchase price under that option will be \$22 million, subject to certain adjustments, payable \$7.5 million upon exercise and the balance over 30 months under a promissory note issuable by Seminole Energy, bearing interest at 8% per annum and secured by a second mortgage lien on the underlying Gathering System assets. See Note 3 – Oil and Gas Properties.

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

(d) *Acquisition Debt.* We issued a note for \$854,818 in 1986 to finance our acquisition of mineral property on Unga Island, Alaska. The debt is repayable without interest in monthly installments of \$2,000 and is secured by liens on the acquired property. The outstanding acquisition debt was \$282,818 at June 30, 2009.

(e) *Total Long-Term Debt and Maturities.* The following tables summarize our total long-term debt at June 30, 2009, as restated, and December 31, 2008, together with the principal payments due each year through 2013 and thereafter. The table does not reflect the reduction of long-term debt by \$28 million from the sale of a 50% undivided interest in our Gathering System on July 15, 2009. See Note 3 – Oil and Gas Properties.

<u>Principal Amount Outstanding</u>	Restated June 30, 2009 ⁽¹⁾	December 31, 2008
Total long-term debt (including current portion) ⁽²⁾	\$ 112,966,367	\$109,294,818
Less current portion	<u>87,703</u>	<u>24,000</u>
Total long-term debt	<u>\$ 112,878,664</u>	<u>\$109,270,818</u>
<u>Maturities of Debt</u>		
Remainder of 2009	\$ 43,385	
2010	30,473,146 ⁽²⁾	
2011	80,093,557	
2012	2,157,461	
2013 and thereafter	198,818	

(1) Does not reflect the \$28 million reduction in our credit facility borrowings from proceeds of the sale of a 50% interest in our Gathering System on July 15, 2009. See Note 3 – Oil and Gas Properties.

(2) Reflects the carrying amount of our 6% convertible notes in the principal amount of \$37,000,000, net of the unamortized debt discount of \$6,616,451 at June 30, 2009 attributable to their embedded conversion feature. See Note 2 – Restatement Adjustments.

Note 9. Capital Stock

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

(b) *Common Shares.* The following table reflects transactions involving our common stock.

<u>Common Shares Issued</u>	<u>Shares</u>	<u>Amount</u>
Balance, December 31, 2007	26,136,064	\$108,842,526
Issued to employees as incentive bonus	50,000	259,690
Issued upon exercise of stock options	<u>357,582</u>	<u>1,524,696</u>
Balance, December 31, 2008	26,543,646	110,626,912
Issued as stock awards under incentive plan	<u>425,000</u>	<u>361,250</u>
Balance, June 30, 2009	<u>26,968,646</u>	<u>\$110,988,162</u>
<u>Paid In Capital – Options and Warrants</u>		
Balance, December 31, 2007		3,484,148
Recognized		625,142
Exercised		<u>(334,690)</u>
Balance, December 31, 2008		3,774,600
Recognized		<u>430,191</u>
Balance, June 30, 2009		<u>\$ 4,204,791</u>
<u>Common Shares to be Issued</u>		
Balance, June 30, 2009 and December 31, 2008	<u>9,185</u>	<u>\$ 45,925</u>

(c) *Stock Options and Awards.* We maintain three stock plans for the benefit of our directors, officers, employees and certain consultants or advisors. The plans provide for the grant of options to purchase up to 3,600,000 common shares and, in the case of our most recent plan, either stock awards or options for an aggregate of up to 4,000,000 common shares. Option grants under all the plans must be at prevailing market prices and may be subject to vesting requirements over a period of up to ten years from the date of grant. Stock awards under the third plan may be subject to vesting conditions and trading restrictions specified at the time of grant. Stock awards and option grants were made under these plans for a total of 425,000 shares during the first half of 2009 and 2,350,000 shares during 2008. The following table shows transactions in stock options during the reported periods.

	<u>Issued</u>	<u>Exercisable</u>	<u>Weighted Average Exercise Price</u>
Balance, December 31, 2007	2,681,250	1,739,583	\$ 4.75
Granted	2,300,000	—	2.93
Vested	—	41,667	6.02
Exercised	(357,582)	(357,582)	3.33
Forfeited	(10,000)	(10,000)	7.04
Balance, December 31, 2008	4,613,668	1,413,668	3.95
Vested	—	1,220,000	4.68
Expired	(310,000)	(310,000)	4.03
Balance, June 30, 2009	4,303,668	2,323,668	3.94

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

<u>Options Outstanding</u>				<u>Options Exercisable</u>	
<u>Exercise Price or Range</u>	<u>Number</u>	<u>Weighted Average Remaining Life (years)</u>	<u>Weighted Average Exercise Price</u>	<u>Number</u>	<u>Weighted Average Exercise Price</u>
\$ 1.51	1,650,000	5.86	\$ 1.51	—	\$ —
4.03 4.09	1,230,000	0.49	4.05	1,230,000	4.05
6.02 7.64	1,423,668	1.86	6.66	1,093,668	6.69
	<u>4,303,668</u>			<u>2,323,668</u>	

In accounting for stock options, we apply the fair value recognition provisions of SFAS No. 123(R), *Share-Based Payment*. We use the Black-Scholes pricing model to determine the fair value of each stock option at the grant date, and we recognize the compensation cost ratably over the vesting period. For the periods presented in the interim consolidated financial statements, the fair value estimates for each option grant assumed a risk free interest rate ranging from 0.03% to 6%, no dividend yield, a theoretical volatility ranging from 0.30 to 0.85 and an expected life ranging from six months to six years based on the vesting provisions of the options. This resulted in non-cash charges for options and warrants of \$625,142 in 2008 and 430,191 in the first half of 2009.

Note 10. Income (Loss) Per Share

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

	Three Months Ended		Six Months Ended	
	June 30,		June 30,	
	2009	2008	2009	2008
	Restated		Restated	
<u>Numerator:</u>				
Net income (loss) as reported for basic EPS.....	\$ (1,935,158)	\$ 1,521,262	\$ (3,366,497)	\$ 1,684,451
Adjustments to income (loss) for diluted EPS.....	—	—	—	—
Net income (loss) for diluted EPS.....	<u>\$ (1,935,198)</u>	<u>\$ 1,521,262</u>	<u>\$ (3,366,497)</u>	<u>\$ 1,684,451</u>
<u>Denominator:</u>				
Weighted average shares for basic EPS.....	26,968,646	26,346,506	26,820,718	26,291,159
Effect of dilutive securities – stock options.....	—	998,023	—	724,002
Adjusted weighted average shares and assumed conversions for diluted EPS	<u>26,968,646</u>	<u>27,344,529</u>	<u>26,820,718</u>	<u>27,015,161</u>
Basic EPS.....	<u>\$ (0.07)</u>	<u>\$ 0.06</u>	<u>\$ (0.13)</u>	<u>\$ 0.06</u>
Diluted EPS.....	<u>\$ (0.07)</u>	<u>\$ 0.06</u>	<u>\$ (0.13)</u>	<u>\$ 0.06</u>

Note 11. Segment Information

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

Note 12. Commitments

We incurred operating lease expenses of \$2,583,417 in 2008 and \$1,347,685 in the first six months of 2009. As of June 30, 2009, we had future obligations under operating leases in the amounts listed below, with no additional commercial commitments other than our long-term debt.

Maturities of Lease Obligations

Remainder of 2009.....	\$ 1,168,146
2010	2,267,973
2011	2,047,086
2012	847,442
2013 and thereafter.....	<u>73,283</u>
Total	<u>\$ 6,403,930</u>

Note 13. Recent Accounting Standards

SFAS No. 168. In July 2009, the FASB issued SFAS No. 168, *Accounting Standards Codification and the Hierarchy of Generally Accepted Accounting Principles*. The Codification is not intended to change U.S. GAAP; but will change the references to existing accounting pronouncements and literature, effective for financial statements covering periods ending after September 15, 2009. Once effective, it will supersede all prior accounting standards under U.S. GAAP, aside from those issued by the SEC. The guidance currently provided in the Codification will not have any impact on our consolidated financial statements.

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

NGAS RESOURCES, INC.

Item 2.

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

General

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

Recent Developments

Liquidity from Sale of Interest in Gathering System. On July 15, 2009, we completed the sale of a 50% undivided interest in our Appalachian gas gathering and midstream facilities (*Gathering System*) for \$28 million. Proceeds from the transaction were applied to reduce outstanding borrowings under our revolving credit facility, which was fully drawn prior to the sale. See "Liquidity and Capital Resources." The sale was covered by an Asset Purchase Agreement (*APA*) among our operating subsidiaries, Daugherty Petroleum, Inc. (*DPI*), NGAS Gathering, LLC and NGAS Gathering II, LLC (*NGAS Gathering II*), with Seminole Gas Company, L.L.C. (*Seminole*). As part of the transaction, we entered into various gas marketing and gas sales arrangements with Seminole and its parent company, Seminole Energy Services, LLC (*Seminole Energy*). In addition to addressing our liquidity constraints through the sale, we retained operating rights and firm capacity rights in the Gathering System under these arrangements. This ensures long-term deliverability for our Appalachian production through the Gathering System, which currently spans 485 miles through parts of southeastern Kentucky, eastern Tennessee and western Virginia. See "Business Strategy."

Option for Sale of Retained Gathering System Interest. At the closing under the *APA*, we granted Seminole Energy a six-month option to buy our retained 50% interest in the Gathering System for \$22 million (*Seminole Option*). If the Seminole Option is exercised, the purchase price will be payable \$7.5 million at closing and the balance over 30 months under a promissory note from Seminole Energy bearing interest at 8% per annum. If certain conditions are met, we have the right to require the exercise of the Seminole Option. Proceeds from any exercise of the Seminole Option will be applied to further reduce our credit facility borrowings, providing us with additional liquidity to take greater advantage of our development opportunities.

Development of Additional Drilling Prospects. We entered into a farmout agreement in May 2009 with Chesapeake Appalachia, LLC for a tract of 56,000 gross (42,000 net undeveloped) acres contiguous to the Amvest portion of our Stone Mountain field in Letcher and Harlan Counties, Kentucky. Chesapeake's prior development of the tract includes approximately 100 producing wells and gathering facilities that connect to our Gathering System. Penn Virginia Operating, LLC, the royalty interest owner, and Chesapeake each have participation rights for up to 25% of the working interests in our future wells on the acreage, and we have a minimum annual drilling commitment of four wells under the farmout, with an additional commitment to drill six vertical Devonian shale wells by the beginning of June 2009. To meet our initial commitment, we entered into arrangements with a joint venture partner that provide us with a 15% carried working interest in these wells, which we completed on schedule with encouraging results. We granted our joint venture partner participation rights for up to 50% of our available working interest in subsequent Devonian shale horizontal wells on the acquired acreage.

Business Strategy

Over 71% of our 329,000-acre position in the Appalachian Basin is undeveloped, along with most of our assembled acreage in the Illinois Basin. Our business is structured for development of these resources, which has been transformed by our use of horizontal drilling throughout our operating areas. We began this transition early in 2008 and had 20 horizontal wells on line at year-end, with an additional five horizontals producing to sales at the end of June 2009. Our success with these initiatives contributed to growth in our production volumes to 3.7 Bcfe in 2008, up 13% over 2007. Despite substantially reduced drilling activity in the first half of 2009, we produced 1.0 Bcf of natural gas equivalents in the second quarter. This represents a 5% increase from the same quarter last year, but a 4% decline from record production volumes in the 2009 first quarter. Having improved our balance sheet and prospects for additional liquidity, our extensive inventory of low-risk, repeatable horizontal drilling locations positions us for future growth under a sustainable, low-cost structure with several components.

- Organic Growth through Drilling with Reduced Capital Spending. While we are committed to a long-term strategy of developing our reserves through the drillbit and retaining most of our available working interest in new wells, we have addressed the challenging conditions in our industry by reducing our 2009 capital spending budget, currently set at \$15 million, and sharing development costs by returning to our successful partnership structure for operated initiatives. We raised over \$34 million for a non-operated program last year through our established sales network. To meet our near-term drilling commitments and objectives, in addition to monetizing our Gathering System, we are currently sponsoring a partnership to participate in up to 53 horizontal wells throughout our operated properties. The partnership commenced operations following an initial closing of its private placement in June 2009. We are maintaining a 20% interest in this year's program and will earn an additional 15% reversionary interest after program payout.
- Horizontal Drilling Initiatives. Recent advances in horizontal drilling and completion technology have enhanced the value proposition for our operated properties by substantially increasing our recovery volumes and rates at dramatically lower finding costs. Horizontal drilling also gives us access to areas where natural gas development would otherwise be delayed or constrained by coal mining activity or challenging terrain. We focused these initiatives during 2008 in our Leatherwood field, where we completed 20 horizontal wells last year. Each well has a single lateral leg up to 3,500 feet through the Devonian shale formation, which is present throughout our Appalachian operating areas. Initial 30-day flow rates for our Leatherwood horizontals averaged 309 Mcf per day. We achieved comparable results for our first two New Albany shale horizontals drilled late in 2008 on our Illinois Basin acreage and our initial Devonian shale horizontals completed during the first quarter of 2009 in each of our Straight Creek, Fonde and Martin's Fork fields. We plan to continue this transition throughout our operated properties.
- Advantages from Restructured Infrastructure Position. The Gathering System covered by our APA with Seminole provides deliverability from 90% of our Appalachian properties directly from the wellhead to major east coast natural gas markets through an interconnect with Spectra Energy Partners' East Tennessee Interstate pipeline network. Although our sale of a 50% interest in our Gathering System eliminated the closed-access status of our field-wide infrastructure, our retained capacity rights ensure long-term deliverability from our operated Appalachian properties serviced by these facilities. These capacity rights, currently established at 30,000 Mcf per day, also preserve our competitive advantages from control of regional gas flow, enhancing our opportunities to acquire undeveloped acreage near our core producing fields upon completion of coal mining activities.

Drilling Operations

General. As of June 30, 2009, we had interests in a total of 1,403 wells, concentrated on Appalachian properties. We believe our long and successful operating history and proven ability to drill a large number of wells year after year have positioned us as a leading producer in this region. Historically, we conducted most of our drilling operations through sponsored drilling partnerships with outside investors, enabling us to assemble our acreage positions on the strength of our drilling commitments, while also funding infrastructure development on acquired acreage for our own account. Beginning in the second half of 2007, with our core Appalachian infrastructure in place, we changed our business model to limit our use of drilling partnerships to participation in non-operated plays, retaining all of our available working interest in wells drilled on operated properties through the end of 2008. To address part of the capital requirements for meeting this year's drilling commitments and objectives, we are sponsoring a drilling partnership for up to \$53.1 million to participate in our horizontal wells during the balance of 2009 and the first quarter of 2010. The partnership commenced operations at the end of June 2009 following the initial closing of its private placement.

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

Horizontal Drilling. Air-driven horizontal drilling advances and staged completion technology optimized for our operating areas have dramatically improved the economics of our shale plays in the Appalachian and Illinois Basins. In general, our horizontal wells use directional air drilling to create a lateral leg up to 3,500 feet through the

target formation. This allows the well bore to stay in contact with the reservoir longer and to intersect more fractures in the formation than conventional vertical wells. While up to four times more expensive than vertical wells, horizontal drilling is improving overall performance by increasing recovery volumes and rates, limiting the number of wells necessary to develop an area through conventional drilling and reducing the costs and surface disturbances of multiple vertical wells. Typically, one horizontal well replaces between three to four vertical locations, reducing the total footprint by drilling fewer wells. Additional economies can be achieved by drilling multiple horizontal wells on a single drilling location. In addition to these operational advantages, the initial recovery rates for these horizontals are averaging six to eight times the rates for our vertical Devonian shale wells in the same fields. Although not fully reflected in our 2008 year-end reserve estimates, we anticipate substantial upside in both production and EURs from our ongoing transition to horizontal drilling.

Staged Completion Technology. Upon completion of drilling the lateral leg of our horizontal wells, we run 4.5-inch casing and packers to the end of the leg, and the packers are set at intervals, allowing the well to be completed in up to eight separate stages within the horizontal leg. A staged treatment process is then performed on our horizontal wells to enhance natural fracturing with large volumes of nitrogen, generally over one-million standard cubic feet per stage. After the well is blown back for approximately seven days, it is connected to our existing field-wide gathering facilities to commence gas sales. We have not completed any of our horizontal wells in up-hole zones to avoid the risk of fluid production from those zones.

New Albany Shale Play. In addition to the recent expansion of Appalachian acreage through our Chesapeake farmout, we are continuing to develop our New Albany shale play within the southcentral portion of the Illinois Basin in western Kentucky. We began producing this project to sales in September 2008, with a total of 37 wells on line at June 30, 2009. Based on encouraging results from our New Albany shale horizontals, we have expanded our lease position and plan to drill up to five horizontal wells on this acreage through our 2009 drilling partnership. See “Business Strategy.”

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

Year Ended December 31, 2008	Development Wells			Exploratory Wells		
	Productive		Dry	Productive		Dry
	Gross	Net	Gross	Gross	Net	Gross
Vertical.....	137	58.8522	—	9	8.8125	—
Horizontal	47	15.7254	—	—	—	—
Total	184	74.5776	—	9	8.8125	—
Six Months Ended June 30, 2009						
Vertical.....	10	1.6972	—	—	—	—
Horizontal	8	1.7588	—	—	—	—
Total	18	3.4560	—	—	—	—

Producing Activities

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

Liquids Extraction. During 2007, in response to regulatory tariffs limiting the upward range of pipeline throughput to 1.1 Dth per Mcf, we constructed a processing plant with Seminole Energy in Rogersville, Tennessee for liquids extraction from our Appalachian production delivered through the Gathering System. See “Recent Developments.” The plant was brought on line in February 2008, ensuring our compliance with the new energy content standard. Sales of extracted liquids have partially offset the reduction in energy-related yields from our

Appalachian gas production. In addition, our margins for sales of extracted liquids have benefited from lower hauling costs achieved through recently implemented rail shipping arrangements.

Oil and Gas Production. Our production revenues and estimated oil and gas reserves are substantially dependent on prevailing market prices for natural gas, which comprised 78% of our proved reserves on an energy equivalent basis at the end of 2008. The following table shows the average sales prices for our oil and gas production during 2008 and the first two quarters of 2009.

	Three Months Ended June 30,		Six Months Ended June 30,		Year Ended December 31,
	2009	2008	2009	2008	2008
Production volumes:					
Natural gas (Mcf).....	836,282	764,530	1,704,830	1,508,528	3,087,596
Oil (Bbl).....	12,149	14,994	25,426	28,482	57,291
Natural gas liquids (gallons).....	<u>1,235,477</u>	<u>1,094,547</u>	<u>2,436,658</u>	<u>1,728,682</u>	<u>3,895,649</u>
Equivalents (Mcf).....	<u>1,001,838</u>	<u>950,268</u>	<u>2,040,135</u>	<u>1,830,682</u>	<u>3,745,124</u>
Average sales prices:					
Natural gas (per Mcf)	\$ 6.47	\$ 9.88	\$ 6.61	\$ 9.21	\$ 8.89
Oil (per Bbl)	51.89	115.54	42.07	103.67	95.07
Natural gas liquids (per gallon)	0.69	1.73	0.67	1.64	1.41

Future Gas Sales Contracts. We use fixed-price, fixed-volume physical delivery contracts that cover portions of our natural gas production at specified prices during varying periods of time to address commodity price volatility. Our physical delivery contracts are not treated as financial hedging activities and are not subject to mark-to-market accounting. The financial impact of these contracts is included in our oil and gas revenues at the time of settlement. As of the date of this report, we have contracts in place for the following portions of our anticipated natural gas production for 2010 and the second half of 2009. The table includes contracts added with Seminole Energy in connection with the closing under the APA, covering monthly production volumes ranging from 55,000 to 120,00 Mcf for one year beginning in April 2010 at \$5.94 per MMBtu plus regional basis adjustments. See “Recent Developments.”

FIXED-PRICE CONTRACTS FOR NATURAL GAS PRODUCTION

	2009		2010
	Q3	Q4	
Average price per Mcf.....	\$ 8.38	\$ 7.82	\$ 6.71
Percent of anticipated gas production contracted	50.7%	55.3%	45.4%

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

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

Revenue:	Three Months Ended June 30,			
	2009	% of Revenue	2008	% Change
Contract drilling.....	\$ 5,172,998	35%	\$ 7,625,356	(32)%
Oil and gas production.....	6,891,644	47	11,179,620	(38)
Gas transmission, compression and processing	<u>2,599,229</u>	<u>18</u>	<u>2,536,560</u>	2
Total.....	<u>\$14,663,871</u>	<u>100%</u>	<u>\$21,341,536</u>	(31)

Our revenue mix for the second quarter of 2009 reflects the impact of declining commodity prices and reduced drilling activity on our strategy for transitioning to a more production based business. During the 2009 second quarter, our oil and gas sales accounted for 47% of total revenues, compared to 52% of total revenues for the second quarter of 2008 and 46% for the year as a whole. In view of our reduction in capital expenditures for 2009, we do not expect this trend to reverse without a significant recovery in commodity prices.

Contract drilling revenues reflect the size and timing of our drilling partnership initiatives. Although we receive the proceeds from private placements in sponsored partnerships as customers' drilling deposits under our program drilling contracts, we recognize revenues from the interests of outside investors in these programs on the completed contract method as the wells are drilled, rather than when funds are received. During 2008, we sponsored a program for participation in 89 wells on non-operated properties known as the HRE fields, spanning six counties in West Virginia and Virginia. Our contract drilling revenues in the second quarter of 2009 reflect the completion of drilling operations for that program and the commencement of operations for our 2009 drilling partnership, which participated in three horizontal wells through the end of the second quarter. We plan to drill up to an additional 50 horizontal wells on our operated properties through our 2009 drilling partnership during the balance of the year and the first quarter of 2010.

Production revenues for the second quarter of 2009 reflect an increase of 5.4% in production output to 1,002 Mmcfe, compared to 950 Mmcfe in the year-earlier period, offset by a 35% decline in natural gas prices, 55% in oil prices and 60% for sales of natural gas liquids. Our volumetric growth reflects strong performance from our horizontal wells and the commencement of production from our Haley's Mill field in western Kentucky during August 2008. Approximately 45% of our natural gas production in the current quarter was sold under fixed-price physical delivery contracts, and the balance primarily at prices determined monthly under formulas based on prevailing market indices. Realized natural gas prices in the 2009 second quarter averaged \$7.68 per Mcf for our Appalachian production and \$6.47 per Mcf overall, compared to an average overall realization of \$9.88 per Mcf in the second quarter of 2008.

Gas transmission, compression and processing revenues for the current quarter were driven by fees totaling \$820,856 for moving our drilling program investors' share of gas through the field-wide portions of the Gathering System and \$397,939 for third-party deliveries through the open-access portion of the system, along with \$232,202 in related processing fees for liquids extraction through our Rogersville plant, which is co-owned with Seminole Energy. This component of revenues also includes contributions of \$72,210 from gas utility sales. We expect our sale of a 50% interest in the Gathering System under our APA with Seminole to result in a significant contraction in our total gas transmission, compression and processing revenues beginning in the third quarter of 2009, with further reductions following any exercise of the Seminole Option. See "Recent Developments."

Expenses. The following table shows the components of our direct and other expenses for the three months ended June 30, 2009 and 2008. Percentages listed in the table reflect margins for each component of direct expenses and percentages of total revenue for each component of other expenses. Certain non-cash expenses for the 2009 interim periods reflect adjustments for the adoption of derivative fair value accounting for our 6% notes as of January 1, 2009. The impact of these adjustments is discussed below and in Note 2 to the accompanying condensed consolidated financial statements.

Direct Expenses:	Three Months Ended June 30,			
	2009	Margin	2008	Margin
Contract drilling.....	\$ 3,873,266	25%	\$ 5,756,997	25%
Oil and gas production.....	2,614,094	62	3,107,095	72
Gas transmission, compression and processing	<u>1,025,408</u>	61	<u>957,548</u>	62
Total direct expenses.....	<u>7,512,768</u>	49	<u>9,821,640</u>	54
Other Expenses:	(Restated)	% Revenue		% Revenue
Selling, general and administrative.....	2,552,740	17%	3,442,094	16%
Options, warrants and deferred compensation.....	319,192	2	234,803	1
Depreciation, depletion and amortization	3,687,621	25	3,261,192	15
Bad debt expense	—	N/A	59,000	—
Interest expense, net of interest income.....	2,409,257	16	1,346,550	6
Fair value loss on derivative financial instruments.....	4,995	—	—	N/A
Other, net	<u>216,377</u>	1	<u>34,632</u>	—
Total other expenses.....	<u>\$ 9,190,182</u>		<u>\$ 8,378,271</u>	

Contract drilling expenses reflect the level and timing of drilling initiatives conducted through our sponsored partnerships. These expenses decreased by 33% on a period-over-period basis and represented 75% of contract drilling revenues in both periods. Margins for contract drilling operations reflect our cost-plus pricing model, which we adopted in 2006 to address price volatility for drilling services, equipment and steel casing requirements.

Production expenses represent lifting costs, field operating and maintenance expenses, related overhead, severance and other production taxes, third-party transportation fees and processing costs. The decrease in production expenses on a period-over-period basis primarily reflects lower severance taxes and the adoption of various cost-cutting measures for our field operations. Our margins in both periods reflect cost savings realized from ownership of our Appalachian Gathering System. Historically, this eliminated transportation and processing fees for our share of Leatherwood, Straight Creek, Fonde and Stone Mountain production delivered through the system. With the sale of a 50% interest in these facilities during July 2009 under our APA with Seminole, our overall production expenses in future periods will be impacted by higher transportation costs, which will be further increased from the sale of our remaining 50% interest in the Gathering System upon any exercise of the Seminole Option. See “Recent Developments.”

Gas transmission, compression and processing expenses in the second quarter of 2009 were 39% of associated revenues, compared to 38% in the same quarter last year. These expenses do not include capitalized costs of approximately \$500,000 in the current quarter for extensions of our field-wide gas gathering systems and additions to dehydration and compression capacity required to bring new wells on line. Our gas transmission and compression expenses as well as capitalized costs for this part of our business will be substantially reduced by our sale of a 50% interest in our Gathering System, with further reductions if the Seminole Option is exercised for our retained interest in these facilities.

Selling, general and administrative (*SG&A*) expenses are comprised primarily of selling and promotional costs for our sponsored drilling partnerships and general overhead costs. Although our *SG&A* expenses in the current quarter decreased by 26% from the same period last year due to the timing of partnership sales, they represented 17% of revenues in the current quarter, compared to 16% in the second quarter of 2008.

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

Depreciation, depletion and amortization (*DD&A*) is recognized under the units-of-production method, based on the estimated proved developed reserves of the underlying oil and gas properties, and on a straight-line basis over the useful life of other property and equipment. The increase in *DD&A* charges reflects additions to our oil and gas properties, gas gathering systems and related equipment.

Cash interest expense for the 2009 second quarter increased nominally from the year-earlier period, reflecting the impact of lower variable rates on higher debt levels under our revolving credit facility. Draws under the facility since the middle of 2008 were used primarily to support ongoing drilling and infrastructure initiatives. The reduction in our credit facility debt from proceeds from the sale of a half interest in our Gathering System during July 2009 and from any subsequent exercise of the Seminole Option, in addition to improving our liquidity, will provide considerable savings on future interest expense. Non-cash interest expense of \$955,627 for the second quarter of 2009 reflects the application of the effective interest method for accretion of the debt discount on the embedded conversion feature of our 6% notes, which have of face amount of \$37,000,000. See “Liquidity and Capital Resources.”

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

Net Income (Loss) and EPS. We recognized a net loss of \$1,935,158 in the second quarter of 2009, as restated, compared to net income of \$1,521,262 realized in the same quarter last year, reflecting the foregoing factors. Basic earnings (loss) per share (*EPS*) was \$(0.07) based on 26,968,646 weighted average common shares outstanding in the current quarter, compared to basic *EPS* of \$0.06 on 26,346,506 weighted average common shares outstanding in the second quarter of 2008. Adjustments for derivative treatment of our 6% convertible notes accounted for \$960,622 of our restated net loss, or \$(0.03) per share, for the second quarter of 2009.

Results of Operations – Six Months Ended June 30, 2009 and 2008

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

<u>Revenue:</u>	<u>Six Months Ended June 30,</u>			
	<u>2009</u>	<u>% of Revenue</u>	<u>2008</u>	<u>% Change</u>
Contract drilling.....	\$ 12,496,750	39%	\$ 14,227,474	(12)%
Oil and gas production.....	13,958,863	44	19,669,054	(29)
Gas transmission, compression and processing.....	<u>5,404,211</u>	<u>17</u>	<u>5,094,652</u>	6
Total.....	<u>\$31,859,824</u>	<u>100%</u>	<u>\$ 38,991,180</u>	(18)

Our contract drilling revenues in the first half of 2009 reflect the completion of drilling operations for our 2008 drilling partnership, which participated in 89 wells on non-operated properties in West Virginia and Virginia, as well as the commencement of operations for our 2009 drilling partnership, which participated in three horizontal wells through the end of the second quarter. We plan to drill up to an additional 50 horizontal wells on our operated properties through our 2009 drilling partnership during the balance of the year and the first quarter of 2010.

Production revenues for the first six months of 2009 reflect an 11% increase in production output to 2,040 Mmcfe, compared to 1,831 Mmcfe in the year-earlier period, offset by a 28% decline in natural gas prices and 59% in sales prices for both oil and natural gas liquids. Our volumetric growth, while negatively impacted by the reduction in drilling activity in the current period, reflects strong performance from last year's horizontal drilling initiatives and the commencement of production from our Haley's Mill field in August 2008. Approximately 45% of our natural gas production in the first half of 2009 was sold under fixed-price contracts, and the balance at index-based pricing. Realized natural gas prices in the current period averaged \$7.89 per Mcf for our Appalachian production and \$6.61 per Mcf overall, compared to an average overall realization of \$9.21 per Mcf in the first half of 2008.

Gas transmission, compression and processing revenues for the current period were driven by fees totaling \$1,657,467 for moving our drilling program investors' share of gas through the field-wide portions of our Appalachian Gathering System and \$827,392 for third-party deliveries through the open-access portion of the system, along with \$340,767 in related processing fees for liquids extraction through our Rogersville plant. This component of revenues also includes contributions of \$329,135 from gas utility sales.

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

<u>Direct Expenses:</u>	<u>Six Months Ended June 30,</u>			
	<u>2009</u>	<u>Margin</u>	<u>2008</u>	<u>Margin</u>
Contract drilling.....	\$ 9,414,692	25%	\$10,876,846	24%
Oil and gas production.....	4,939,059	65	5,872,050	70
Gas transmission, compression and processing.....	<u>1,994,325</u>	63	<u>2,047,794</u>	60
Total direct expenses.....	<u>16,348,076</u>	49	<u>18,796,690</u>	52
<u>Other Expenses:</u>	<u>(Restated)</u>	<u>% Revenue</u>		<u>% Revenue</u>
Selling, general and administrative.....	5,803,005	18%	6,730,577	17%
Options, warrants and deferred compensation.....	737,465	2	372,482	1
Depreciation, depletion and amortization.....	7,306,491	23	6,132,952	16
Bad debt expense.....	—	N/A	406,840	1
Interest expense, net of interest income.....	4,681,449	15	2,602,810	7
Gain on derivative.....	(9,324)	N/A	—	N/A
Other, net.....	<u>295,918</u>	1	<u>28,355</u>	—
Total other expenses.....	<u>\$18,815,004</u>		<u>\$16,274,016</u>	

Contract drilling expenses decreased by 13% on a period-over-period basis and represented 75% of contract drilling revenues in the first half of 2009, compared to 76% in the year-earlier period. Our contract drilling activities in the current period were limited to the completion of drilling on non-operated HRE properties in West Virginia and Virginia for last year's drilling partnership and the commencement of operations for our 2009 drilling partnership, which participated in three horizontal wells through the end of the second quarter.

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

Gas transmission, compression and processing expenses in the first half of 2009 were 37% of associated revenues, compared to 40% in the same period last year. These expenses do not include capitalized costs of approximately \$1.3 million in the current period for extensions of our field-wide gas gathering systems and additions to dehydration and compression capacity required to bring new wells on line.

SG&A expenses in the current period decreased 14% from the same period last year. This primarily reflects the reduced level of drilling partnership sales, which are subject to considerable fluctuation and generally ramp up in the second half of the year. As a percentage of revenues, SG&A expenses increased to 18% in the first half of 2009, compared to 17% of revenues in the year-earlier period.

Non-cash charges for options, warrants and deferred compensation reflect the fair value method of accounting for employee stock options. Under this method, employee stock options are valued at the grant date using the Black-Scholes valuation model, and the compensation cost is recognized ratably over the vesting period. We also recognized an accrual of \$307,274 for deferred compensation cost in the current period.

The increase in DD&A for the current period reflects additions to our oil and gas properties, gas gathering systems and related equipment. We anticipate reductions in our DD&A rates of approximately 5% from the sale of a half interest in our Gathering System and approximately 10% following any exercise of the Seminole Option. See "Recent Developments."

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

Cash interest expense for the first half of 2009 increased nominally from the year-earlier period, reflecting lower variable rates under our revolving credit facility on higher debt levels under our revolving credit facility. Draws under the facility since the middle of 2008 were used primarily to support our ongoing drilling initiatives and enhancements of our field-wide gas gathering systems. Non-cash interest expense of \$1,864,594 for the first six months of 2009 reflects the accretion of the debt discount on our 6% convertible notes.

Net Income (Loss) and EPS. We recognized a net loss of \$3,366,497 in the six months of 2009, as restated, compared to net income of \$1,684,451 realized in the same period last year, reflecting the foregoing factors. Basic EPS was \$(0.06) on 26,820,718 weighted average common shares outstanding in the current period, compared to EPS of \$0.13 based on 26,291,159 weighted average common shares outstanding in the first half of 2008. Adjustments for derivative treatment of our 6% convertible notes accounted for \$1,855,270 of our restated net loss, or \$(0.07) per share, for the first six months of 2009.

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

Liquidity and Capital Resources

Liquidity. Net cash of \$3,243,065 was provided by operating activities in the first half of 2009. During the period, we used \$6,500,659 in investing activities, most of which reflects net additions to our oil and gas properties and gathering systems. These investments were funded in part with net cash of \$9,917,714 from financing activities, primarily consisting of advances under our revolving credit facility. As a result of these activities, cash increased from \$981,899 at December 31, 2008 to \$7,642,019 at June 30, 2009.

As of June 30, 2009, we had working capital of \$5,135,844, compared to a working capital deficit of \$5,519,114 at December 31, 2008. This reflects wide fluctuations in our current assets and liabilities from the timing of customer deposits and expenditures under drilling contracts with our sponsored partnerships, as well as a substantial increase in our cash position from draws under our credit facility. Since these fluctuations are normalized over relatively short time periods, we do not consider working capital to be a reliable measure of liquidity.

Capital Resources. Our business involves significant capital requirements. The rate of production from oil and gas properties declines as reserves are depleted. Without successful development activities, our proved reserves would decline as oil and gas is produced from our proved developed reserves. We also have substantial annual drilling commitments under various leases and farmouts for our Appalachian properties, including an annual 25-well commitment for our Leatherwood field. Our long-term performance and profitability is dependent not only on

meeting these commitments and recovering existing oil and gas reserves, but also on our ability to find or acquire additional reserves and fund their development on terms that are economically and operationally advantageous.

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

While we are committed to continue expanding our reserves and production through the drillbit, we have addressed the challenging conditions in our industry by reducing our 2009 capital spending budget to \$15 million, allocated primarily to drilling. This is in line with our anticipated cash flow from operations and may be adjusted during the year in response to market developments. To meet our 2009 drilling commitments and objectives with limited reliance on additional draws under our credit facility, we are returning to our established partnership structure and sales network, which raised over \$34 million for a non-operated program last year. We expect to maintain a 20% interest in this year's program, which will increase to 35% after program payout. With our critical infrastructure in place, this will allow us to continue delivering organic growth, although at lower rates than we could otherwise achieve.

We have a senior secured revolving credit facility maintained by DPI under a credit agreement with KeyBank National Association, as administrative agent for the lenders. The credit agreement provides for revolving term loans and letters of credit in an aggregate amount up to \$125 million, with a borrowing base of \$80 million at December 31, 2008 and June 30, 2009. As of June 30, 2009, the credit facility was fully drawn, and the interest rate amounted to 5.5%. The facility is secured by liens on our proved oil and gas properties. Obligations under the facility have a scheduled maturity in September 2011 and are guaranteed by NGAS.

On June 2, 2009, we entered into an amendment to the credit agreement to establish a semi-annual redetermination of our borrowing base and provide various modifications to permit the sale of interests in our Gathering System under the APA with Seminole and upon any exercise of the Seminole Option. See "Recent Developments." The amendment provides for the following modifications to the credit agreement, which became effective on July 15, 2009 upon the closing of the sale under the APA:

- Redetermination of the borrowing base at \$55 million, which included a \$10 million reduction to reflect the release of our Gathering System assets from the collateral package under the credit agreement;
- Change in the maximum interest rate for borrowings under the credit agreement to 2.25% above the administrative agent's prime rate;
- Waiver of current ratio financial covenant under the credit agreement until September 30, 2009, and
- Adjustments to our other financial covenants under the credit agreement through December 31, 2010.

Under the terms of the credit agreement amendment, our proceeds of \$28 million from the sale of a 50% undivided interest in the Gathering System were applied to reduce our outstanding borrowings under the credit facility. As of the date of this report, we have \$46 million outstanding under the facility, with \$9 million of credit availability. The credit agreement amendment also provides for the further repayment of our outstanding borrowings with the additional proceeds from any exercise of the Seminole Option. The purchase price under the Seminole Option is \$22 million, subject to certain adjustments. If the Seminole Option is exercised, the purchase price will be payable \$7.5 million at closing and the balance over 30 months under a promissory note issuable by Seminole Energy, bearing interest at 8% per annum and secured by a second mortgage lien on the underlying Gathering System assets. See "Recent Developments – Option for Sale of Retained Gathering System Interest."

We have an outstanding series of 6% convertible notes due December 15, 2010 in the aggregate principal amount of \$37 million. The notes are convertible into our common shares at a conversion price of \$12.94. In the event of a default under the notes or any change of control, the holders may require us to redeem the notes at a default rate equal to 125% of their principal amount or a change of control rate equal to the greater of 110% of their principal amount or the consideration that would be received by the holders for the underlying shares in the change of control transaction. Any notes that are neither redeemed nor converted prior to maturity will be repayable in cash or in common shares, valued for that purpose at 92.5% of their prevailing market price.

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

We have addressed the general economic downturn and current unsettled conditions in natural gas markets by monetizing our Gathering System, reducing our capital expenditure budget and returning to our established drilling partnership structure for participation in our development initiatives. To realize our long-term goals for growth in revenues and reserves, however, we will continue to be dependent on the credit and capital markets or other financing alternatives. Any prolonged constriction in the capital markets could require us to sell assets or pursue other financing or strategic arrangements to meet those objectives and to repay or refinance our long-term debt at maturity.

Forward Looking Statements

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

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

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

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, 2009 under these instruments.

<u>Year</u>	<u>Operating Leases</u>			<u>Long Term Debt</u>
	<u>Equipment</u>	<u>Premises</u>	<u>Total</u>	
Remainder of 2009	\$ 1,044,619	\$ 123,527	\$ 1,168,146	\$ 43,385
2010	2,020,158	247,815	2,267,973	30,473,146 ⁽¹⁾
2011	1,794,697	252,389	2,047,086	80,093,557 ⁽²⁾
2012	591,469	255,973	847,442	2,157,461
2013 and thereafter	<u>51,929</u>	<u>21,355</u>	<u>73,284</u>	<u>198,818</u>
Total	<u>\$ 5,502,872</u>	<u>\$ 901,059</u>	<u>\$ 6,403,931</u>	<u>\$ 112,966,367</u>

(1) Excludes the unamortized debt discount of \$6,616,451 at June 30, 2009 attributable to the embedded conversion feature of our 6% convertible notes in the principal amount of \$37,000,000.

(2) Does not reflect the \$28 million reduction in our credit facility borrowings from proceeds of the sale of a 50% interest in our Gathering System on July 15, 2009.

Critical Accounting Policies and Estimates

General. The preparation of financial statements requires management to utilize estimates and make judgments that affect the reported amounts of assets, liabilities, revenues and expenses and related disclosure of contingent assets and liabilities. These estimates are based on historical experience and on various other assumptions that management believes to be reasonable under the circumstances. The estimates are evaluated by management on an ongoing basis, and the results of these evaluations form a basis for making decisions about the carrying value of assets and liabilities that are not readily apparent from other sources. Although actual results may differ from these estimates under different assumptions or conditions, management believes that the estimates used in the preparation of our financial statements are reasonable. The critical accounting policies affecting these aspects of our financial reporting are summarized or referenced in Notes 1 and 2 to the consolidated financial statements included in this 10-Q/A. Policies involving the more significant judgments and estimates used in the preparation of our consolidated financial statements are summarized below.

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

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

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

Item 3. Quantitative and Qualitative Disclosures about Market Risk

Commodity Price Risk

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

Financial Market Risks

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

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

Item 4. Controls and Procedures

Management's Responsibility for Financial Statements

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

Disclosure Controls and Procedures

Our management, with the participation of our chief executive officer and chief financial officer, evaluated the effectiveness of our disclosure controls and procedures, as defined in Rule 13a-15(e) under the Exchange Act, as of the end of the period covered by this report. Based on management's evaluation as of June 30, 2009 and as of December 31, 2009 in connection with the filing of this 10-Q/A, our chief executive officer and chief financial officer have concluded that our disclosure controls and procedures are effective to ensure that material information about our business and operations is recorded, processed, summarized and publicly reported within the time periods required under the Exchange Act, and that this information is accumulated and communicated to our management to allow timely decisions about required disclosures.

Management's Report on Internal Control over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as defined in Rule 13a-15(f) under the Exchange Act. Management assessed the effectiveness of our internal control over financial reporting as of June 30, 2009 and as of December 31, 2009 in connection with the filing of this 10-Q/A, using the criteria established under *Internal Control – Integrated Framework*, issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on that assessment, management concluded that our internal control over financial reporting was effective based on those criteria as of June 30, 2009 and December 31, 2009.

Changes in Internal Control over Financial Reporting

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

Part II -- Item 6

Exhibit

<u>Number</u>	<u>Description of Exhibit</u>
31.1	Certification of Chief Executive Officer pursuant to Exchange Act Rule 13a-14(a), as adopted under Section 302 of the Sarbanes-Oxley Act of 2002.
31.2	Certification of Chief Financial Officer pursuant to Exchange Act Rule 13a-14(a), as adopted under Section 302 of the Sarbanes-Oxley Act of 2002.
32.1	Certification of Chief Executive Officer pursuant to Exchange Act Rule 13a-14(b), as adopted under Section 906 of the Sarbanes-Oxley Act of 2002.
32.2	Certification of Chief Financial Officer pursuant to Exchange Act Rule 13a-14(b), as adopted under Section 906 of the Sarbanes-Oxley Act of 2002.

SIGNATURES

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

NGAS RESOURCES, INC.

Date: December 31, 2009

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

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

In connection with the amended quarterly report of NGAS Resources, Inc. on Form 10-Q/A for the quarter ended June 30, 2009, as filed with the Securities Exchange Commission on the date hereof under the Securities Exchange Act of 1934, the undersigned certifies pursuant to Rule 13a-14(a) or 15d-14(a) under the Exchange Act that:

1. I have reviewed this amended quarterly report on Form 10-Q/A 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 periods 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 periods 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

December 31, 2009

**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 amended quarterly report of NGAS Resources, Inc. on Form 10-Q/A for the quarter ended June 30, 2009, as filed with the Securities Exchange Commission on the date hereof under the Securities Exchange Act of 1934, the undersigned certifies pursuant to Rule 13a-14(a) or 15d-14(a) under the Exchange Act that:

1. I have reviewed this amended quarterly report on Form 10-Q/A 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/ MICHAEL P. WINDISCH

Michael P. Windisch,
Chief Financial Officer

December 31, 2009

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

In connection with the amended quarterly report of NGAS Resources, Inc. on Form 10-Q/A for the quarter ended June 30, 2009, as filed with the Securities Exchange Commission on the date hereof under the Securities Exchange Act of 1934, the undersigned, William S. Daugherty, certifies pursuant to Rule 13a-14(b) or 15d-14(b) under the Exchange Act that:

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

/s/ WILLIAM S. DAUGHERTY

William S. Daugherty,
Chairman, Chief Executive Officer and President

December 31, 2009

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

In connection with the quarterly report of NGAS Resources, Inc. on Form 10-Q for the quarter ended June 30, 2009, as filed with the Securities Exchange Commission on the date hereof under the Securities Exchange Act of 1934, the undersigned, Michael P. Windisch, certifies pursuant to Rule 13a-14(b) or 15d-14(b) under the Exchange Act that:

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

/s/ MICHAEL P. WINDISCH

Michael P. Windisch,
Chief Financial Officer

December 31, 2009