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

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**FORM 10-Q**

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**QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15 (d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the quarterly period ended September 30, 2009

OR

**TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from \_\_\_\_\_ to \_\_\_\_\_

Commission File Number 1-8182

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**PIONEER DRILLING COMPANY**

(Exact name of registrant as specified in its charter)

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**TEXAS**  
(State or other jurisdiction of  
incorporation or organization)

**74-2088619**  
(I.R.S. Employer  
Identification Number)

**1250 N.E. Loop 410, Suite 1000, San Antonio, Texas**  
(Address of principal executive offices)

**78209**  
(Zip Code)

**210-828-7689**  
(Registrant's telephone number, including area code)

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Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes  No

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive 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 whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer," and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer

Accelerated filer

Non-accelerated filer

Smaller reporting company

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

As of October 23, 2009, there were 50,306,552 shares of common stock, par value \$0.10 per share, of the registrant issued and outstanding.

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## PART I. FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTSPIONEER DRILLING COMPANY AND SUBSIDIARIES  
CONDENSED CONSOLIDATED BALANCE SHEETS

	September 30, 2009 (unaudited)	December 31, 2008 (audited)
	(In thousands)	
<b>ASSETS</b>		
Current assets:		
Cash and cash equivalents	\$ 53,305	\$ 26,821
Receivables:		
Trade, net of allowance for doubtful accounts	31,293	76,176
Insurance recoveries	18,363	5,951
Income taxes	11,164	5,034
Unbilled	10,008	12,262
Deferred income taxes	4,336	6,270
Inventory	4,855	3,874
Prepaid expenses and other current assets	3,250	8,902
Total current assets	<u>136,574</u>	<u>145,290</u>
Property and equipment, at cost	922,384	858,491
Less accumulated depreciation and amortization	<u>305,130</u>	<u>230,929</u>
Net property and equipment	617,254	627,562
Intangible assets, net of amortization	26,539	29,969
Other long-term assets	<u>18,626</u>	<u>21,658</u>
Total assets	<u>\$ 798,993</u>	<u>\$ 824,479</u>
<b>LIABILITIES AND SHAREHOLDERS' EQUITY</b>		
Current liabilities:		
Accounts payable	\$ 16,680	\$ 21,830
Current portion of long-term debt	2,093	17,298
Prepaid drilling contracts	—	1,171
Accrued expenses:		
Payroll and related employee costs	7,517	13,592
Insurance premiums and deductibles	10,178	11,569
Insurance claims and settlements	18,363	5,951
Other	<u>8,721</u>	<u>9,507</u>
Total current liabilities	63,552	80,918
Long-term debt, less current portion	260,259	262,115
Other long-term liabilities	6,054	6,413
Deferred income taxes	<u>65,325</u>	<u>60,915</u>
Total liabilities	<u>395,190</u>	<u>410,361</u>
Commitments and contingencies		
Shareholders' equity:		
Preferred stock, 10,000,000 shares authorized; none issued and outstanding	—	—
Common stock \$.10 par value; 100,000,000 shares authorized; 50,306,552 shares and 49,997,578 shares issued and outstanding at September 30, 2009 and December 31, 2008, respectively	5,031	5,000
Additional paid-in capital	307,218	301,923
Treasury stock, at cost; 5,174 shares and no shares at September 30, 2009 and December 31, 2008, respectively	(31)	—
Accumulated earnings	93,609	108,440
Accumulated other comprehensive loss	<u>(2,024)</u>	<u>(1,245)</u>
Total shareholders' equity	403,803	414,118
Total liabilities and shareholders' equity	<u>\$ 798,993</u>	<u>\$ 824,479</u>

See accompanying notes to condensed consolidated financial statements.



PIONEER DRILLING COMPANY AND SUBSIDIARIES  
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS

(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2009	2008	2009	2008
	(In thousands, except per share data)			
<b>Revenues:</b>				
Drilling services	\$ 48,084	\$124,297	\$165,170	\$333,587
Production services	<u>26,282</u>	<u>49,948</u>	<u>79,156</u>	<u>106,602</u>
Total revenue	<u>74,366</u>	<u>174,245</u>	<u>244,326</u>	<u>440,189</u>
<b>Costs and expenses:</b>				
Drilling services	35,315	70,342	107,880	198,115
Production services	16,638	25,025	50,260	53,871
Depreciation and amortization	26,952	24,225	78,467	61,924
Selling, general and administrative	8,892	12,840	27,870	32,712
Bad debt (recovery) expense	<u>(1,409)</u>	<u>(260)</u>	<u>(1,713)</u>	<u>(216)</u>
Total costs and expenses	<u>86,388</u>	<u>132,172</u>	<u>262,764</u>	<u>346,406</u>
Income (loss) from operations	<u>(12,022)</u>	<u>42,073</u>	<u>(18,438)</u>	<u>93,783</u>
<b>Other (expense) income:</b>				
Interest expense	(1,839)	(3,773)	(5,555)	(9,612)
Interest income	43	205	182	995
Other	<u>222</u>	<u>(1,551)</u>	<u>847</u>	<u>(1,389)</u>
Total other expense	<u>(1,574)</u>	<u>(5,119)</u>	<u>(4,526)</u>	<u>(10,006)</u>
Income (loss) before income taxes	(13,596)	36,954	(22,964)	83,777
Income tax benefit (expense)	<u>4,406</u>	<u>(12,760)</u>	<u>8,133</u>	<u>(28,619)</u>
Net earnings (loss)	<u>\$ (9,190)</u>	<u>\$ 24,194</u>	<u>\$ (14,831)</u>	<u>\$ 55,158</u>
Earnings (loss) per common share—Basic	<u>\$ (0.18)</u>	<u>\$ 0.49</u>	<u>\$ (0.30)</u>	<u>\$ 1.11</u>
Earnings (loss) per common share—Diluted	<u>\$ (0.18)</u>	<u>\$ 0.48</u>	<u>\$ (0.30)</u>	<u>\$ 1.09</u>
Weighted average number of shares outstanding—Basic	<u>49,845</u>	<u>49,791</u>	<u>49,831</u>	<u>49,780</u>
Weighted average number of shares outstanding—Diluted	<u>49,845</u>	<u>50,449</u>	<u>49,831</u>	<u>50,426</u>

See accompanying notes to condensed consolidated financial statements.

PIONEER DRILLING COMPANY AND SUBSIDIARIES  
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

(Unaudited)

	Nine Months Ended September 30,	
	2009	2008
	(In thousands)	
<b>Cash flows from operating activities:</b>		
Net earnings (loss)	\$ (14,831)	\$ 55,158
Adjustments to reconcile net earnings (loss) to net cash provided by operating activities:		
Depreciation and amortization	78,467	61,924
Allowance for doubtful accounts	(1,237)	270
Gain on dispositions of property and equipment	(84)	(512)
Stock-based compensation expense	5,561	2,924
Deferred income taxes	7,527	10,700
Change in other assets	1,061	355
Change in non-current liabilities	(1,169)	(329)
Changes in current assets and liabilities:		
Receivables	42,208	(29,447)
Inventory	(876)	(1,501)
Prepaid expenses & other current assets	5,651	(1,687)
Accounts payable	(2,553)	4,194
Income tax payable	—	5,107
Prepaid drilling contracts	(1,171)	1,514
Accrued expenses	(8,253)	17,085
<b>Net cash provided by operating activities</b>	<b><u>110,301</u></b>	<b><u>125,755</u></b>
<b>Cash flows from investing activities:</b>		
Acquisition of production services business of WEDGE	—	(313,606)
Acquisition of production services business of Competition	—	(26,770)
Acquisition of production services business of Paltec	—	(6,520)
Purchases of property and equipment	(67,058)	(99,794)
Purchase of auction rate preferred securities	—	(16,475)
Proceeds from sale of property and equipment	608	2,712
Proceeds from insurance recoveries	36	2,638
<b>Net cash used in investing activities</b>	<b><u>(66,414)</u></b>	<b><u>(457,815)</u></b>
<b>Cash flows from financing activities:</b>		
Debt repayments	(17,060)	(44,404)
Proceeds from issuance of debt	—	319,500
Debt issuance costs	(77)	(3,319)
Proceeds from exercise of options	—	672
Purchase of treasury stock	(31)	—
Excess tax benefit (reductions) for stock option exercises	(235)	250
<b>Net cash (used in) provided by financing activities</b>	<b><u>(17,403)</u></b>	<b><u>272,699</u></b>
<b>Net increase (decrease) in cash and cash equivalents</b>	<b>26,484</b>	<b>(59,361)</b>
<b>Beginning cash and cash equivalents</b>	<b>26,821</b>	<b>76,703</b>
<b>Ending cash and cash equivalents</b>	<b><u>\$ 53,305</u></b>	<b><u>\$ 17,342</u></b>
<b>Supplementary disclosure:</b>		
Interest paid	\$ 5,426	\$ 8,668
Income tax (refunded) paid	\$ (9,234)	\$ 11,436

See accompanying notes to condensed consolidated financial statements.

PIONEER DRILLING COMPANY AND SUBSIDIARIES  
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

**1. Nature of Operations and Summary of Significant Accounting Policies**

***Business and Basis of Presentation***

Pioneer Drilling Company and subsidiaries provide drilling and production services to our customers in select oil and natural gas exploration and production regions in the United States and Colombia. Our Drilling Services Division provides contract land drilling services with its fleet of 71 drilling rigs in the following locations:

<u>Drilling Division Locations</u>	<u>Rig Count</u>
South Texas	17
East Texas	21
North Dakota	7
North Texas	4
Utah	6
Oklahoma	6
Appalachia	3
Colombia / International	7

As of October 23, 2009, 27 drilling rigs are operating under drilling contracts, one of which is earning revenues through early termination fees on its contract with a term that expires in December 2009. We have 38 drilling rigs that are idle and six drilling rigs have been placed in storage or "cold stacked" in our Oklahoma drilling division due to low demand for drilling rigs in that region. We are actively marketing all our idle drilling rigs both domestically and internationally in Latin America. During the second quarter of 2009, we established our Appalachian drilling division and now have three drilling rigs operating in the Marcellus Shale region. We have five drilling rigs located in Colombia that are operating under drilling contracts and we are marketing two additional drilling rigs for international expansion in Latin America.

Our Production Services Division provides a broad range of well services to oil and gas drilling and producing companies, including workover services, wireline services, and fishing and rental services. Our production services operations are managed regionally and are concentrated in the major United States onshore oil and gas producing regions in the Gulf Coast, Mid-Continent, Rocky Mountain and Appalachian states. We have a premium fleet of 74 workover rigs consisting of sixty-nine 550 horsepower rigs, four 600 horsepower rigs, and one 400 horsepower rig. As of October 23, 2009, 65 workover rigs have crews assigned and are either operating or are being actively marketed. The remaining nine workover rigs in our fleet are idle with no crews assigned. We provide wireline services with a fleet of 61 wireline units and rental services with approximately \$15 million of fishing and rental tools.

The accompanying unaudited condensed consolidated financial statements include the accounts of Pioneer Drilling Company and its wholly owned subsidiaries. All intercompany balances and transactions have been eliminated in consolidation. The accompanying unaudited condensed consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America for interim financial information and with the instructions to Form 10-Q and Rule 10-01 of Regulation S-X. Accordingly, they do not include all of the information and footnotes required by generally accepted accounting principles for complete financial statements. In the opinion of our management, all adjustments (consisting of normal, recurring accruals) necessary for a fair presentation have been included. In preparing the accompanying unaudited condensed consolidated financial statements, we make various estimates and assumptions that affect the amounts of assets and liabilities we report as of the dates of the balance sheets and income and expenses we report for the periods shown in the income statements and statements of cash flows. Our actual results could differ significantly from those estimates. Material estimates that are particularly susceptible to significant changes in the near term relate to our recognition of revenues and costs for turnkey contracts, our estimate of the allowance for doubtful accounts, our estimate of the liability relating to the self-insurance portion of our health and workers' compensation insurance, our estimate of asset impairments, our estimate of deferred taxes and our determination of depreciation and amortization expense. The condensed consolidated balance sheet as of December 31, 2008 has been derived from our audited financial statements. We suggest that you read these condensed consolidated financial statements together with the consolidated financial statements and the related notes included in our annual report on Form 10-K for the fiscal year ended December 31, 2008.

In preparing the accompanying unaudited condensed consolidated financial statements, we have reviewed, as we have determined necessary, events that have occurred after September 30, 2009, through the filing of this Form 10-Q on November 5, 2009.

## ***Recently Issued Accounting Standards***

***Accounting Standards Codification.*** The Financial Accounting Standards Board's (FASB) Accounting Standards Codification (ASC) became effective on July 1, 2009. At that date, the ASC became FASB's officially recognized source of authoritative U.S. generally accepted accounting principles (GAAP) applicable to all public and non-public non-governmental entities, superseding existing FASB Statements of Financial Accounting Standards (SFAS) and other authoritative guidance issued by the American Institute of Certified Public Accountants (AICPA) and Emerging Issues Task Force (EITF). Rules and interpretive releases of the SEC under the authority of federal securities laws are also sources of authoritative GAAP for SEC registrants. All other accounting literature is considered non-authoritative. The switch to the ASC affects the way companies refer to U.S. GAAP in financial statements and accounting policies. Citing particular content in the ASC involves specifying the unique numeric path to the content through the Topic, Subtopic, Section and Paragraph structure.

***Noncontrolling Interests in Consolidated Financial Statements.*** In December 2007, the FASB issued new authoritative accounting guidance under FASB ASC Topic 810 (formerly SFAS No. 160) which establishes accounting and reporting standards for the non-controlling interest in a subsidiary and for the deconsolidation of a subsidiary. ASC Topic 810 clarifies that a non-controlling interest in a subsidiary, which is sometimes referred to as minority interest, is an ownership interest in the consolidated entity that should be reported as a component of equity in the consolidated financial statements. Among other requirements, ASC 810 requires consolidated net income to be reported at amounts that include the amounts attributable to both the parent and the non-controlling interest. It also requires disclosure, on the face of the consolidated income statement, of the amounts of consolidated net income attributable to the parent and to the non-controlling interest. ASC Topic 810 is effective for fiscal years beginning on or after December 15, 2008. The adoption of ASC topic 810 on January 1, 2009 did not have a material impact on our financial position or results of operations and financial condition.

***Business Combinations.*** On January 1, 2009, new authoritative accounting guidance became effective under ASC Topic 805 (formerly SFAS No. 141R) which applies to all transactions and other events in which one entity obtains control over one or more other businesses. ASC Topic 805 requires an acquirer, upon initially obtaining control of another entity, to recognize the assets, liabilities and any non-controlling interest in the acquiree at fair value as of the acquisition date. Contingent consideration is required to be recognized and measured at fair value on the date of acquisition rather than at a later date when the amount of that consideration may be determinable beyond a reasonable doubt. This fair value approach replaces the cost-allocation process required under the previous authoritative accounting guidance (formerly SFAS No. 141) whereby the cost of an acquisition was allocated to the individual assets acquired and liabilities assumed based on their estimated fair value. ASC Topic 805 requires acquirers to expense acquisition-related costs as incurred rather than allocating such costs to the assets acquired and liabilities assumed, as was previously the case under SFAS No. 141. Under ASC Topic 805, the requirements of ASC Topic 420 (formerly SFAS No. 146) relating to the accounting for costs associated with exit or disposal activities, would have to be met in order to accrue for a restructuring plan in purchase accounting. Pre-acquisition contingencies are to be recognized at fair value, unless it is a non-contractual contingency that is not likely to materialize, in which case, nothing should be recognized in purchase accounting and, instead, that contingency would be subject to the probable and estimable recognition criteria of ASC Topic 450 which provides accounting guidance for contingencies. ASC Topic 805 had no impact on our financial position or results of operations and financial condition, since we have not had any business combinations closing on or after the January 1, 2009 effective date.

***Disclosures about Derivative Instruments and Hedging Activities.*** On January 1, 2009, new authoritative accounting guidance became effective under ASC Topic 815 (formerly SFAS No. 161) which changes the disclosure requirements for derivative instruments and hedging activities. Entities are required to provide enhanced disclosures about (a) how and why an entity uses derivative instruments, (b) how derivative instruments and related hedged items are accounted for under ASC Topic 815, and (c) how derivative instruments and related hedged items affect an entity's financial position, financial performance, and cash flows. The guidance in ASC Topic 815 is effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008, with early application encouraged. This authoritative accounting guidance encourages, but does not require, comparative disclosures for earlier periods at initial adoption. We do not have any derivative instruments and the January 1, 2009 adoption of this new accounting guidance under ASC Topic 815 had no impact on our financial statement disclosures.

***Fair Value Measurements and Disclosures.*** Effective for accounting periods ending after June 15, 2009, new authoritative accounting guidance under ASC Topic 820 (formerly FASB Staff Position FAS 157-4) provides additional guidance for estimating fair value when the volume and level of activity for the asset or liability have significantly decreased and provides additional guidance on disclosure requirements. ASC Topic 820 also includes guidance on identifying circumstances that indicate a transaction is not orderly. The adoption of the new authoritative accounting guidance under ASC Topic 820 during our quarter ending June 30, 2009 did not have a material impact on our financial position or results of operations and financial condition.

***Other-than-temporary Impairments.*** Effective for accounting periods ending after June 15, 2009, new authoritative accounting guidance under ASC Topic 320 (formerly FASB Staff Position FAS 115-2 and 124-2) modifies the indicator of other-than-temporary impairment for debt securities. Additionally, ASC Topic 320 changes the amount of an other-than-temporary impairment that is recognized in earnings when there are credit losses on a debt security that management does not intend to sell and it is more-likely-than-not that the entity will not have to sell prior to recovery of the noncredit impairment. In those situations, the portion of the total

impairment that is attributable to the credit loss would be recognized in earnings, and the remaining difference between the debt

security's amortized cost basis and its fair value would be included in other comprehensive income. The adoption of this new authoritative accounting guidance under ASC Topic 320 during our quarter ending June 30, 2009 did not have a material impact on our financial position or results of operations and financial condition.

*Interim Disclosures about Fair Value of Financial Instruments.* Effective for accounting periods ending after June 15, 2009, new authoritative accounting guidance under ASC Topic 825 (formerly FASB Staff Position FAS 107-1 and APB 28-1) requires disclosures about fair value of financial instruments in quarterly reports as well as in annual reports and applies to certain investments and long-term debt. The adoption of this new authoritative accounting guidance under ASC Topic 825 during our quarter ending June 30, 2009 did not have a material impact on our financial position or results of operations and financial condition.

*Subsequent Events.* For accounting periods ending after June 15, 2009, new authoritative accounting guidance became effective under ASC Topic 855 (formerly SFAS No. 165) which modifies the definition of what qualifies as a subsequent event—those events or transactions that occur following the balance sheet date, but before the financial statements are issued, or are available to be issued—and requires companies to disclose the date through which it has evaluated subsequent events and the basis for determining that date. The adoption of ASC Topic 855 during the quarter ended June 30, 2009 did not have a material impact on our financial position or results of operations and financial condition.

*Multiple Deliverable Revenue Arrangements.* In October 2009, the FASB issued Accounting Standards Update, 2009-13, Revenue Recognition (Topic 605) *Multiple Deliverable Revenue Arrangements – A Consensus of the FASB Emerging Issues Task Force*. This update provides application guidance on whether multiple deliverables exist, how the deliverables should be separated and how the consideration should be allocated to one or more units of accounting. This update establishes a selling price hierarchy for determining the selling price of a deliverable. The selling price used for each deliverable will be based on vendor-specific objective evidence, if available, third-party evidence if vendor-specific objective evidence is not available, or estimated selling price if neither vendor-specific or third-party evidence is available. We will be required to apply this guidance prospectively for revenue arrangements entered into or materially modified after January 1, 2011; however, earlier application is permitted. We do not expect the adoption of this new guidance to have a material impact on our financial position or results of operations.

### ***Drilling Contracts***

Our drilling contracts generally provide for compensation on either a daywork, turnkey or footage basis. Contract terms generally depend on the complexity and risk of operations, the on-site drilling conditions, the type of equipment used and the anticipated duration of the work to be performed. Generally, our contracts provide for the drilling of a single well and typically permit the customer to terminate on short notice. However, we have entered into more longer-term drilling contracts during periods of high rig demand. In addition, we have entered into longer-term drilling contracts for our newly constructed rigs. As of October 23, 2009, we had five contracts with terms of six months to three years in duration, of which two will expire by December 31, 2009, one will expire by April 30, 2010, one will expire by December 31, 2010 and one will expire by June 30, 2012.

### ***Foreign Currencies***

Our functional currency for our foreign subsidiary in Colombia is the U.S. dollar. Nonmonetary assets and liabilities are translated at historical rates and monetary assets and liabilities are translated at exchange rates in effect at the end of the period. Income statement accounts are translated at average rates for the period. Gains and losses from remeasurement of foreign currency financial statements into U.S. dollars and from foreign currency transactions are included in other income or expense.

### ***Restricted Cash***

As of September 30, 2009, we had restricted cash in the amount of \$2.6 million held in an escrow account to be used for future payments in connection with the acquisition of Prairie Investors d/b/a Competition Wireline ("Competition"). The former owner of Competition will receive annual installments of \$0.7 million payable over the remaining four years from the escrow account. Restricted cash of \$0.7 million and \$1.9 million is recorded in other current assets and other long-term assets, respectively. The associated obligation of \$0.7 million and \$1.9 million is recorded in accrued expenses and other long-term liabilities, respectively.

On August 28, 2008, we deposited \$0.9 million into a trust account in accordance with the terms of the severance agreement in connection with the resignation of our former Chief Financial Officer. This balance was distributed to the former Chief Financial Officer on March 3, 2009.

### ***Inventories***

Inventories primarily consist of drilling rig replacement parts and supplies held for use by our Drilling Services Division's operations and supplies held for use by our Production Services Division's operations. Inventories are valued at the lower of cost (first in, first out or actual) or market value.

## ***Investments***

Other long-term assets include investments in tax exempt, auction rate preferred securities (“ARPS”). Our ARPSs are classified with other long-term assets on our condensed consolidated balance sheet as of September 30, 2009 because of our inability to determine the recovery period of our investments.

At September 30, 2009, we held \$15.9 million (par value) of ARPSs, which are variable-rate preferred securities and have a long-term maturity with the interest rate being reset through “Dutch auctions” that are held every 7 days. The ARPSs have historically traded at par because of the frequent interest rate resets and because they are callable at par at the option of the issuer. Interest is paid at the end of each auction period. Our ARPSs are AAA/Aaa rated securities, collateralized by municipal bonds and backed by assets that are equal to or greater than 200% of the liquidation preference. Until February 2008, the auction rate securities market was highly liquid. Beginning mid-February 2008, we experienced several “failed” auctions, meaning that there was not enough demand to sell all of the securities that holders desired to sell at auction. The immediate effect of a failed auction is that such holders cannot sell the securities at auction and the interest rate on the security resets to a maximum auction rate. We have continued to receive interest payments on our ARPSs in accordance with their terms. We may not be able to access the funds we invested in our ARPSs without a loss of principal, unless a future auction is successful or the issuer calls the security pursuant to redemption prior to maturity. We have no reason to believe that any of the underlying municipal securities that collateralize our ARPSs are presently at risk of default. We believe we will ultimately recover the par value of the ARPS without a loss, primarily due to the collateral securing the ARPSs and our estimate of the discounted cash flows that we expect to collect. We do not currently intend to sell our ARPSs at a loss. Also, we believe it is more-likely-than-not that we will not have to sell our ARPS prior to recovery, since our liquidity needs are expected to be met with cash flows from operating activities and our senior secured revolving credit facility. See Note 3 “Long-term Debt” below regarding compliance with the covenants in our credit agreement.

Our ARPSs are reported at amounts that reflect our estimate of fair value. ASC Topic 820 (formerly SFAS No. 157), provides a hierarchical framework associated with the level of subjectivity used in measuring assets and liabilities at fair value. To estimate the fair values of our ARPSs, we used inputs defined by ASC Topic 820 as level 3 inputs which are unobservable for the asset or liability and are developed based on the best information available in the circumstances. We estimate the fair value of our ARPSs based on discounted cash flow models and secondary market comparisons of similar securities. In addition, during the quarter ended June 30, 2009, we adopted the new accounting guidance under ASC Topic 320 when we evaluated the fair value of our ARPS and evaluated whether the fair value discount represented an other-than-temporary impairment.

Our ARPSs are designated as available-for-sale and are reported at fair market value with the related unrealized gains or losses, included in accumulated other comprehensive income (loss), net of tax, a component of shareholders’ equity. The estimated fair value of our ARPSs at September 30, 2009 was \$12.7 million compared with a par value of \$15.9 million. The \$3.2 million difference represents a fair value discount due to the current lack of liquidity which is considered temporary and has been recorded as an unrealized loss, net of tax, in accumulated other comprehensive income (loss). We recorded \$2.0 million of this fair value discount during the year ended December 31, 2008 and the remaining \$1.2 million was recorded during the nine months ended September 30, 2009. There was no portion of the fair value discount attributable to credit losses. We would recognize an impairment charge in our statement of operations if the fair value of our investments falls below the cost basis and is judged to be other-than-temporary or is judged to be attributable to credit losses.

## ***Income Taxes***

Pursuant to ASC Topic 740 (formerly SFAS No. 109), we follow the asset and liability method of accounting for income taxes, under which we recognize deferred tax assets and liabilities for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax basis. We measure our deferred tax assets and liabilities by using the enacted tax rates we expect to apply to taxable income in the years in which we expect to recover or settle those temporary differences. Under ASC Topic 740, we reflect in income the effect of a change in tax rates on deferred tax assets and liabilities in the period during which the change occurs.

### Comprehensive Income (Loss)

Comprehensive income (loss) is comprised of net income and other comprehensive loss. Other comprehensive loss includes the change in the fair value of our ARPSs, net of tax, for the three and nine months ended September 30, 2009 and 2008. The following table sets forth the components of comprehensive income (loss):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2009	2008	2009	2008
Net income (loss)	\$(9,190)	\$24,194	\$(14,831)	\$55,158
Other comprehensive loss—unrealized loss on ARPS securities	(10)	(256)	(779)	(1,206)
Comprehensive income (loss)	\$(9,200)	\$23,938	\$(15,610)	\$53,952

### Stock-based Compensation

We recognize compensation cost for stock-based compensation based on the grant-date fair value estimated in accordance with ASC Topic 718 (formerly SFAS No. 123R) and we utilize the graded vesting method. Compensation costs of approximately \$3.3 million and \$0.8 million for stock options were recognized in selling, general and administrative expense and operating costs, respectively, for the nine months ended September 30, 2009. We receive a tax deduction for certain stock option exercises during the period the options are exercised, generally for the excess of the fair market value of our stock on the date of exercise over the exercise price of the options. In accordance with ASC Topic 718, we reported all excess tax benefits resulting from the exercise of stock options as financing cash flows in our consolidated statement of cash flows. There were no stock options exercised during the nine months ended September 30, 2009.

We estimate the fair value of each option grant on the date of grant using a Black-Scholes options-pricing model. The following table summarizes the assumptions used in the Black-Scholes option-pricing model for the three and nine months ended September 30, 2009 and 2008:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2009	2008	2009	2008
Weighted average expected volatility	61%	44%	58%	44%
Weighted-average risk-free interest rates	2.5%	2.8%	2.1%	2.6%
Weighted-average expected life in years	5.00	3.74	5.48	3.74
Options granted	42,000	1,057,098	1,526,550	1,402,098
Weighted-average grant-date fair value	\$ 2.84	\$ 6.11	\$ 2.09	\$ 5.77

The assumptions above are based on multiple factors, including historical exercise patterns of homogeneous groups with respect to exercise and post-vesting employment termination behaviors, expected future exercising patterns for these same homogeneous groups and volatility of our stock price. As we have not declared dividends since we became a public company, we did not use a dividend yield. In each case, the actual value that will be realized, if any, will depend on the future performance of our common stock and overall stock market conditions. There is no assurance the value an optionee actually realizes will be at or near the value we have estimated using the Black-Scholes options-pricing model.

Restricted common stock awards vest over a 3 year period. The fair value of restricted common stock is based on the closing price of our common stock on the date of the grant. We amortize the fair value of the restricted common stock awards to compensation expense using the graded vesting method. For the nine months ended September 30, 2009, 326,748 restricted common stock awards were granted with a weighted-average grant date price of \$4.23. Compensation costs of approximately \$1.3 million and \$0.2 for restricted common stock awards were recognized in selling, general and administrative expense and operating costs, respectively, for the nine months ended September 30, 2009.

Effective January 1, 2009, we adopted the new authoritative accounting guidance under FASB ASC Topic 260 (formerly Staff Position No. EITF 03-6-1) which requires restricted common stock granted under our stock-based compensation plans to be treated as participating securities under the two-class method of determining basic earnings per common share. Basic earnings per common share for prior periods are to be adjusted to conform to accounting guidance under ASC Topic 260. The adoption of ASC Topic 260 did not have any effect on the calculation of basic earnings per common share for the three and nine month periods ended September 30, 2009 and 2008.

### **Related-Party Transactions**

Our Chief Executive Officer, President of Drilling Services Division, Senior Vice President of Drilling Services Division—Marketing, and a Vice President of Drilling Services Division—Operations occasionally own a 1% to 5% working interest in oil and gas wells that we drill for one of our customers. These individuals did not own a working interest in any wells that we drilled for this customer during both the nine months ended September 30, 2009 and 2008.

In connection with the acquisitions of the production services businesses from WEDGE Group Incorporated (“WEDGE”) and Competition on March 1, 2008, we have leases for various operating and office facilities with entities that are owned by former WEDGE employees and Competition employees that are now employees of our company. Rent expense for the nine months ended September 30, 2009 was approximately \$0.5 million for these related party leases. In addition, we have non-compete agreements with several former WEDGE employees that are now employees of our company. These non-compete agreements are recorded as intangible assets with a cost, net of accumulated amortization, of \$0.9 million as of September 30, 2009. See Note 2 “Acquisitions” below for further information.

We had aggregate purchases of \$0.4 million of goods and services during the nine months ended September 30, 2009 from twelve vendors that are owned by company employees or family members of company employees.

### **Reclassifications**

Certain amounts in the condensed consolidated financial statements for the prior year have been reclassified to conform to the current year’s presentation.

## **2. Acquisitions**

On March 1, 2008, we acquired the production services business from WEDGE which provided well services, wireline services and fishing and rental services with a fleet of 62 workover rigs, 45 wireline units and approximately \$13 million of fishing and rental equipment through its facilities in Texas, Kansas, North Dakota, Colorado, Utah and Oklahoma. The aggregate purchase price for the acquisition was approximately \$314.7 million, which consisted of assets acquired of \$340.8 million and liabilities assumed of \$26.1 million. The aggregate purchase price includes \$3.4 million of costs incurred to acquire the production services business from WEDGE. We financed the acquisition with approximately \$3.2 million of cash on hand and \$311.5 million of debt incurred under our senior secured revolving credit facility described below in Note 3 “Long-term Debt”.

The following table summarizes the allocation of the purchase price and related acquisition costs to the estimated fair value of the assets acquired and liabilities assumed as of the date of acquisition (amounts in thousands):

Cash acquired	\$ 1,168
Other current assets	22,102
Property and equipment	138,493
Intangible asset and other assets	66,118
Goodwill	112,869
Total assets acquired	<u>\$340,750</u>
Current liabilities	\$ 10,655
Long-term debt	1,462
Other long-term liabilities	13,949
Total liabilities assumed	<u>\$ 26,066</u>
Net assets acquired	<u>\$314,684</u>

The following unaudited pro forma consolidated summary financial information gives effect of the acquisition of the production services business from WEDGE as though it was effective as of January 1, 2008. Pro forma adjustments primarily relate to additional depreciation, amortization and interest costs. The pro forma information reflects our company’s historical data and historical data from the acquired production services business from WEDGE for the period indicated. The pro forma data may not be indicative of the results we would have achieved had we completed the acquisition on January 1, 2008, or what we may achieve in the future and should be read in conjunction with the accompanying historical financial statements.

	<b>Pro Forma Nine Months Ended September 30, 2008</b>
Total revenues	\$ 463,840
Net earnings	\$ 55,539
Earnings per common share	
Basic	\$ 1.12
Diluted	\$ 1.10

On March 1, 2008, immediately following the acquisition of the production services business from WEDGE, we acquired the production services business from Competition which provided wireline services with a fleet of 6 wireline units through its facilities in Montana. The aggregate purchase price for the Competition acquisition was approximately \$30.0 million, which consisted of assets acquired of \$30.1 million and liabilities assumed of \$0.1 million. The aggregate purchase price includes \$0.4 million of costs incurred to acquire the production services business from Competition. We financed the acquisition with \$26.7 million cash on hand and a note payable due to the prior owner for \$3.3 million. Goodwill of \$5.3 million and intangible assets and other assets of \$18.0 million were recorded in connection with the acquisition.

On August 29, 2008, we acquired the wireline services business from Paltec, Inc. The aggregate purchase price was \$7.8 million which we financed with \$6.5 million in cash and a seller note of \$1.3 million. Intangible and other assets of \$4.3 million and goodwill of \$0.1 million were recorded in connection with the acquisition.

On October 1, 2008, we acquired the well services business from Pettus Well Service. The aggregated purchase price was \$3.0 million which we financed with \$2.8 million in cash and a sellers note of \$0.2 million. Intangible and other assets of \$1.2 million and goodwill of \$0.1 million were recorded in connection with the acquisition.

The acquisitions of the production services businesses from WEDGE, Competition, Paltec and Pettus were accounted for as acquisitions of businesses. The purchase price allocations for these production services businesses were finalized as of December 31, 2008. Goodwill was recognized as part of the WEDGE, Competition, Paltec and Pettus acquisitions since the purchase price exceeded the estimated fair value of the assets acquired and liabilities assumed. The goodwill was related to the acquired workforces, expected synergies between our Drilling Services Division and our Production Services Division and the ability to expand our service offerings. These acquisitions occurred between March 1, 2008 and October 1, 2008, when production service revenues, margins and cash flows and our market capitalization were at historically high levels. Our goodwill impairment analysis performed at December 31, 2008 led us to conclude that there would be no remaining implied value attributable to our goodwill and accordingly, we recorded a non-cash charge of \$118.6 million for a full impairment of goodwill relating to these acquisitions. We also performed an impairment analysis at December 31, 2008 which resulted in an impairment charge of \$52.8 million and reduction in the intangible asset carrying value of customer relationships relating to these acquisitions. These impairment charges were primarily related to significant adverse changes in the economic and business climate that began during the fourth quarter of the year ended December 31, 2008.

### 3. Long-term Debt

Long-term debt as of September 30, 2009 consists of the following (amounts in thousands):

Senior secured credit facility	\$257,500
Subordinated notes payable	4,587
Other	265
	<u>262,352</u>
Less current portion	<u>(2,093)</u>
	<u>\$260,259</u>

#### *Senior Secured Revolving Credit Facility*

On February 29, 2008, we entered into a credit agreement with Wells Fargo Bank, N.A. and a syndicate of lenders (the "Initial Credit Agreement"). On October 5, 2009, we entered into a First Amendment to the Initial Credit Agreement (the "Amended Credit Agreement").

*Initial Credit Agreement* – The Initial Credit Agreement provided for a senior secured revolving credit facility, with sub-limits for letters of credit and swing-line loans, of up to an aggregate principal amount of \$400 million, all of which would have matured on February 28, 2013. The Initial Credit Agreement contained customary mandatory prepayments in respect of asset dispositions, debt

incurrences and equity issuances which prepayments were applied to reduce outstanding revolving and swing-line loans and letter of credit exposure without a permanent reduction of commitments. Our obligations under the Initial Credit Agreement were secured by substantially all of our domestic assets (excluding any equity interests in, and any assets of, Pioneer Global Holdings, Inc. and its subsidiaries, which are the entities that comprise our international operations) and were guaranteed by certain of our domestic subsidiaries (excluding Pioneer Global Holdings, Inc.). Borrowings under the Initial Credit Agreement bore interest, at our option, at the bank prime rate or at the LIBOR rate, plus an applicable per annum margin in each case. The applicable per annum margin was determined based upon our leverage ratio in accordance with a pricing grid in the Initial Credit Agreement. The per annum margin for LIBOR rate borrowings ranged from 1.50% to 2.50% and the per annum margin for bank prime rate borrowings ranged from 0.50% to 1.50%. The LIBOR margin and bank prime rate margin in effect at September 30, 2009 were 2.00% and 1.00%, respectively. A commitment fee was due quarterly based on the average daily unused amount of the commitments of the lenders under the Initial Credit Agreement. In addition, a fronting fee was due for each letter of credit issued and a quarterly letter of credit fee was due based on the average undrawn amount of letters of credit outstanding during such period. Borrowings under the Initial Credit Agreement were used to fund the WEDGE acquisition and were available for acquisitions, working capital and other general corporate purposes.

*Amended Credit Agreement*—Effective October 5, 2009, our Amended Credit Agreement provides for a senior secured revolving credit facility, with sub-limits for letters of credit and swing-line loans, of up to an aggregate principal amount of \$325 million, all of which mature on August 31, 2012. The Amended Credit Agreement contains customary mandatory prepayments in respect of asset dispositions, debt incurrences and equity issuances, and commencing with the fiscal year ending December 31, 2009, if the senior consolidated leverage ratio is greater than 2.50 to 1.00 at the end of any fiscal year, the Amended Credit Agreement requires mandatory prepayments equal to 50% of our excess cash flows. Borrowings and commitments under the Amended Credit Agreement will be reduced concurrently with the application of certain mandatory prepayments by the amount of such mandatory prepayment. The aggregate availability under the Amended Credit Agreement shall in no event be required to be reduced to less than \$200,000,000 as a result of such mandatory prepayments. Our obligations under the Amended Credit Agreement are secured by substantially all of our domestic assets (including equity interests in Pioneer Global Holdings, Inc. and 65% of the outstanding equity interests of any first-tier foreign subsidiaries owned by Pioneer Global Holdings, Inc., but excluding any equity interest in, and any assets of, Pioneer Services Holdings, LLC) and are guaranteed by certain of our domestic subsidiaries, including Pioneer Global Holdings, Inc. Borrowings under the Amended Credit Agreement bear interest, at our option, at the bank prime rate or at the LIBOR rate, plus an applicable per annum margin in each case. The applicable per annum margin is determined based upon our leverage ratio in accordance with a pricing grid in the Amended Credit Agreement. The per annum margin for LIBOR rate borrowings ranges from 3.50% to 6.00% and the per annum margin for bank prime rate borrowings ranges from 2.50% to 5.00%. The LIBOR margin and bank prime rate margin in effect at October 23, 2009 are 3.5% and 2.5%, respectively. A commitment fee is due quarterly based on the average daily unused amount of the commitments of the lenders under the Amended Credit Agreement. In addition, a fronting fee is due for each letter of credit issued and a quarterly letter of credit fee is due based on the average undrawn amount of letters of credit outstanding during such period. Borrowings under the Amended Credit Agreement are available for acquisitions, working capital and other general corporate purposes.

The financial covenants contained in our Initial Credit Agreement and Amended Credit Agreement include the following:

- A maximum total consolidated leverage ratio that cannot exceed:
  - 2.75 to 1.00 as of the end of the fiscal quarter ended September 30, 2009;
  - 4.25 to 1.00 as of the end of the fiscal quarter ending December 31, 2009;
  - 5.00 to 1.00 as of the end of any fiscal quarter ending March 31, 2010 through June 30, 2011;
  - 4.75 to 1.00 as of the end of the fiscal quarter ending September 30, 2011;
  - 4.50 to 1.00 as of the end of the fiscal quarter ending December 31, 2011;
  - 4.25 to 1.00 as of the end of the fiscal quarter ending March 31, 2012; and
  - 4.00 to 1.00 as of the end of any fiscal quarter ending June 30, 2012 and thereafter.
- A maximum senior consolidated leverage ratio, which excludes unsecured and subordinated debt, that cannot exceed:
  - 4.25 to 1.00 as of the end of the fiscal quarter ending December 31, 2009;
  - 5.00 to 1.00 as of the end of the fiscal quarters ending March 31, 2010 and June 30, 2010;
  - 4.75 to 1.00 as of the end of the fiscal quarter ending September 30, 2010;
  - 4.50 to 1.00 as of the end of the fiscal quarter ending December 31, 2010;
  - 4.25 to 1.00 as of the end of the fiscal quarter ending March 31, 2011;
  - 4.00 to 1.00 as of the end of the fiscal quarter ending June 30, 2011;
  - 3.75 to 1.00 as of the end of the fiscal quarter ending September 30, 2011;
  - 3.50 to 1.00 as of the end of the fiscal quarter ending December 31, 2011;

- 3.25 to 1.00 as of the end of the fiscal quarter ending March 31, 2012; and
- 3.00 to 1.00 as of the end of any fiscal quarter ended June 30, 2012 and thereafter.

- A minimum interest coverage ratio that cannot be less than:
  - 3.00 to 1.00 as of the end of the fiscal quarters ending September 30, 2009 and December 31, 2009;
  - 2.00 to 1.00 as of the end of any fiscal quarter ending March 31, 2010 through December 31, 2011; and
  - 3.00 to 1.00 as of the end of any fiscal quarter ending March 31, 2012 and thereafter.
- If our senior consolidated leverage ratio is greater than 2.25 to 1.00 at the end of any fiscal quarter, a minimum asset coverage ratio that cannot be less than 1.25 to 1.00 for the quarter ended September 30, 2009 (as provided in our Initial Credit Agreement) and a minimum asset coverage ratio that cannot be less than 1.00 to 1.00 for any fiscal quarter ending on or before December 31, 2011, and 1.10 to 1.00 for any fiscal quarter ending March 31, 2012 and thereafter (as provided in the Amended Credit Agreement). If our senior consolidated leverage ratio is greater than 2.25 to 1.00 and our asset coverage ratio is less than 1.00 to 1.00, then borrowings outstanding under the Amended Credit Agreement will be limited to the sum of 80% of eligible accounts receivable, 80% of the orderly liquidation value of eligible equipment and 40% of the net book value of certain other fixed assets.

The Amended Credit Agreement restricts capital expenditures unless (a) after giving effect to such capital expenditure, no event of default would exist under the Amended Credit Agreement and availability under the Amended Credit Agreement would be equal to or greater than \$25 million and (b) if the senior consolidated leverage ratio as of the last day of the most recent reported fiscal quarter was equal to or greater than 2.50 to 1.00, such capital expenditure would not cause the sum of all capital expenditures to exceed:

- \$52 million for the second half of fiscal year 2009;
- \$65 million for fiscal year 2010; and
- \$80 million for each fiscal year thereafter.

The capital expenditure thresholds for each period noted above may be increased by:

- the first \$25 million of any aggregate equity issuance proceeds received during such period and 25% of any equity issuance proceeds received in excess of \$25 million during such period; and
- 25% of any debt incurrence proceeds received during such period.

In addition, any unused portion of the capital expenditure threshold up to \$30 million can be carried over from the immediate preceding fiscal year.

At September 30, 2009, we were in compliance with our financial covenants. Our total consolidated leverage ratio was 2.32 to 1.00, our interest coverage ratio was 13.08 to 1.00 and our asset coverage ratio was 1.39 to 1.00. The senior consolidated leverage ratio was not a part of our Initial Credit Agreement so it was not applicable at September 30, 2009. The Amended Credit Agreement has additional restrictive covenants that, among other things, limit the incurrence of additional debt, investments, liens, dividends, acquisitions, redemptions of capital stock, prepayments of indebtedness, asset dispositions, mergers and consolidations, transactions with affiliates, hedging contracts, sale leasebacks and other matters customarily restricted in such agreements. In addition, the Amended Credit Agreement contains customary events of default, including without limitation, payment defaults, breaches of representations and warranties, covenant defaults, cross-defaults to certain other material indebtedness in excess of specified amounts, certain events of bankruptcy and insolvency, judgment defaults in excess of specified amounts, failure of any guaranty or security document supporting the credit agreement and change of control.

#### *Subordinated Notes Payable and Other*

In addition to amounts outstanding under the senior secured revolving credit facility, long-term debt includes subordinated notes payable to certain employees that are former shareholders of the production services businesses that were acquired by WEDGE prior to our acquisition of WEDGE on March 1, 2008, a subordinated note payable to an employee that is a former shareholder of Competition, two subordinated notes payable to certain employees that are former shareholders of Paltec, Inc. and Pettus Well Service. These subordinated notes payable have interest rates ranging from 5.4% to 14%, require quarterly or annual payments of principal and interest and have final maturity dates ranging from November 2010 to March 2013. The aggregate outstanding balance of these subordinated notes payable was \$4.6 million as of September 30, 2009.

Other debt represents financing arrangements for computer software with an outstanding balance of \$0.3 million at September 30, 2009.

### Fair Value Measurement

The fair value of our long-term debt is estimated using a discounted cash flow analysis, based on rates that we believe we would currently pay for similar types of debt instruments. This discounted cash flow analysis based on observable inputs for similar types of debt instruments represents level 2 inputs as defined by ASC Topic 820 (formerly SFAS No. 157). The following table presents the supplemental fair value information about long-term debt at September 30, 2009 and December 31, 2008 (amounts in thousands):

	September 30, 2009		December 31, 2008	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Total debt	\$262,352	\$252,067	\$279,413	\$250,943

### 4. Commitments and Contingencies

In connection with our expansion into international markets, our foreign subsidiaries have obtained bonds for bidding on drilling contracts, performing under drilling contracts, and remitting customs and importation duties. We have guaranteed payments of \$27.2 million relating to our performance under these bonds.

On July 9, 2009, we reached a settlement in a wrongful death lawsuit filed against our Drilling Services Division in 2008. We agreed to pay the family of the deceased \$16.0 million, all but \$1.0 million of which will be covered by our insurance carriers. The \$1.0 million of settlement costs, which were paid by us, are included in our Drilling Service Division's operating costs for the nine months ended September 30, 2009. Our insurance carriers have paid \$1.0 million as of September 30, 2009 and will pay the remainder of the settlement obligation to the family of the deceased in installments from October 2009 through December 2009. The settlement costs that are payable by our insurance carriers are reflected on our condensed consolidated balance sheet at September 30, 2009 as \$14.0 million of "accrued expenses – insurance claims and settlements" with an offsetting \$14.0 million reflected as "receivables—insurance recoveries."

Due to the nature of our business, we are, from time to time, involved in litigation or subject to disputes or claims related to our business activities, including workers' compensation claims and employment-related disputes. Legal costs relating to these matters are expensed as incurred. In the opinion of our management, none of the pending litigation, disputes or claims against us will have a material adverse effect on our financial condition, results of operations or cash flow from operations.

### 5. Earnings (Loss) Per Common Share

The following table presents a reconciliation of the numerators and denominators of the basic earnings (loss) per share and diluted earnings (loss) per share computations (amounts in thousands, except per share data):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2009	2008	2009	2008
<b>Basic</b>				
Net earnings (loss)	\$ (9,190)	\$24,194	\$ (14,831)	\$55,158
Weighted average shares	49,845	49,791	49,831	49,780
Earnings (loss) per share	\$ (0.18)	\$ 0.49	\$ (0.30)	\$ 1.11
<b>Diluted</b>				
Net earnings (loss)	\$ (9,190)	\$24,194	\$ (14,831)	\$55,158
Weighted average shares:				
Outstanding	49,845	49,791	49,831	49,780
Diluted effect of stock options	—	658	—	646
	49,845	50,449	49,831	50,426
Earnings (loss) per share	\$ (0.18)	\$ 0.48	\$ (0.30)	\$ 1.09

Outstanding stock options and restricted common stock awards representing 254,115 and 188,313 shares of common stock were excluded from the diluted loss per share calculations for the three and nine month periods ended September 30, 2009, respectively, because the effect of their inclusion would be antidilutive, or would decrease the reported loss per share.

## 6. Equity Transactions

Employees, former employees and directors did not exercise any stock options during the nine months ended September 30, 2009. Employees and former employees exercised stock options for the purchase of 143,054 shares of common stock during the nine months ended September 30, 2008 at prices ranging from \$3.70 to \$10.31 per share.

Employees and directors were awarded 326,748 shares of restricted common stock with a weighted-average grant date price of \$4.23 during the nine months ended September 30, 2009 and 178,261 shares of restricted common stock with a weighted-average of \$17.07 for the nine months ended September 30, 2008.

## 7. Segment Information

At September 30, 2009, we had two operating segments referred to as the Drilling Services Division and the Production Services Division which is the basis management uses for making operating decisions and assessing performance. Prior to our acquisitions of the production services businesses from WEDGE and Competition on March 1, 2008, all our operations related to the Drilling Services Division and we reported these operations in a single operating segment. The acquisitions of the production services businesses from WEDGE and Competition resulted in the formation of our Production Services Division. See Note 2 “Acquisitions” above for further information.

*Drilling Services Division*—Our Drilling Services Division provides contract land drilling services with its fleet of 71 drilling rigs that are assigned to the following regions:

Drilling Division Locations	Rig Count
South Texas	17
East Texas	21
North Dakota	7
North Texas	4
Utah	6
Oklahoma	6
Appalachia	3
Colombia / International	7

*Production Services Division*—Our Production Services Division provides a broad range of well services to oil and gas drilling and producing companies, including workover services, wireline services, and fishing and rental services. Our production services operations are managed regionally and are concentrated in the major United States onshore oil and gas producing regions in the Gulf Coast, Mid-Continent, Rocky Mountain and Appalachian states. We have a premium fleet of 74 workover rigs consisting of sixty-nine 550 horsepower rigs, four 600 horsepower rigs, and one 400 horsepower rig. We provide wireline services with a fleet of 61 wireline units and rental services with approximately \$15 million of fishing and rental tools.

The following tables set forth certain financial information for our two operating segments and corporate for the three months ended September 30, 2009 and 2008 (amounts in thousands):

	<u>As of and for the Three Months Ended September 30, 2009</u>			
	<u>Drilling Services Division</u>	<u>Production Services Division</u>	<u>Corporate</u>	<u>Total</u>
Identifiable assets	\$ 540,413	\$ 228,832	\$ 29,748	\$ 798,993
Revenues	\$ 48,084	\$ 26,282	\$ —	\$ 74,366
Operating costs	35,315	16,638	—	51,953
Segment margin	\$ 12,769	\$ 9,644	\$ —	\$ 22,413
Depreciation and amortization	\$ 20,649	\$ 5,929	\$ 374	\$ 26,952
Capital expenditures	\$ 16,876	\$ 2,298	\$ 67	\$ 19,241

	As of and for the Three Months Ended September 30, 2008			
	Drilling Services Division	Production Services Division	Corporate	Total
Identifiable assets	\$ 545,863	\$ 388,687	\$ 25,526	\$ 960,076
Revenues	\$ 124,297	\$ 49,948	\$ —	\$ 174,245
Operating costs	70,342	25,025	—	95,367
Segment margin	\$ 53,955	\$ 24,923	\$ —	\$ 78,878
Depreciation and amortization	\$ 16,754	\$ 7,368	\$ 103	\$ 24,225
Capital expenditures	\$ 29,560	\$ 16,893	\$ 918	\$ 47,371

The following tables set forth certain financial information for our two operating segments and corporate for the nine months ended September 30, 2009 and 2008 (amounts in thousands):

	As of and for the Nine Months Ended September 30, 2009			
	Drilling Services Division	Production Services Division	Corporate	Total
Identifiable assets	\$ 540,413	\$ 228,832	\$ 29,748	\$ 798,993
Revenues	\$ 165,170	\$ 79,156	\$ —	\$ 244,326
Operating costs	107,880	50,260	—	158,140
Segment margin	\$ 57,290	\$ 28,896	\$ —	\$ 86,186
Depreciation and amortization	\$ 59,774	\$ 17,556	\$ 1,137	\$ 78,467
Capital expenditures	\$ 53,867	\$ 9,929	\$ 665	\$ 64,461

	As of and for the Nine Months Ended September 30, 2008			
	Drilling Services Division	Production Services Division	Corporate	Total
Identifiable assets	\$ 545,863	\$ 388,687	\$ 25,526	\$ 960,076
Revenues	\$ 333,587	\$ 106,602	\$ —	\$ 440,189
Operating costs	198,115	53,871	—	251,986
Segment margin	\$ 135,472	\$ 52,731	\$ —	\$ 188,203
Depreciation and amortization	\$ 48,900	\$ 12,739	\$ 285	\$ 61,924
Capital expenditures	\$ 72,673	\$ 26,875	\$ 1,228	\$ 100,776

The following table reconciles the segment profits reported above to income from operations as reported on the condensed consolidated statements of operations (amounts in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2009	2008	2009	2008
Segment margin	\$ 22,413	\$ 78,878	\$ 86,186	\$ 188,203
Depreciation and amortization	(26,952)	(24,225)	(78,467)	(61,924)
Selling, general and administrative	(8,892)	(12,840)	(27,870)	(32,712)
Bad debt recovery (expense)	1,409	260	1,713	216
Income (loss) from operations	\$ (12,022)	\$ 42,073	\$ (18,438)	\$ 93,783

The following table sets forth certain financial information for our international operations in Colombia which is included in our Drilling Services Division (amounts in thousands):

	As of and for the		As of and for the	
	Three Months Ended September 30,		Nine Months Ended September 30,	
	2009	2008	2009	2008
Identifiable assets	\$ 113,605	\$ 110,513	\$ 113,605	\$ 110,513
Revenues	\$ 14,525	\$ 13,813	\$ 39,321	\$ 33,539

#### 8. Subsequent Event

At December 31, 2008, we established an allowance for doubtful accounts of \$1.3 million relating to a customer's past due account receivable balance based on our best estimate of credit losses. The customer has sold certain assets, and on October 29, 2009, we received payment in full of the past due account receivable balance. We recorded the associated bad debt recovery in the quarter ended September 30, 2009.

## ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Statements we make in the following discussion that express a belief, expectation or intention, as well as those that are not historical fact, are forward-looking statements that are subject to risks, uncertainties and assumptions. Our actual results, performance or achievements, or industry results, could differ materially from those we express in the following discussion as a result of a variety of factors, including general economic and business conditions and industry trends, the continued strength or weakness of the contract land drilling industry in the geographic areas in which we operate, decisions about onshore exploration and development projects to be made by oil and gas companies, the highly competitive nature of our business, the availability, terms and deployment of capital, future compliance with covenants under our senior secured revolving credit facility, the availability of qualified personnel, and changes in, or our failure or inability to comply with, government regulations, including those relating to the environment. We have discussed many of these factors in more detail elsewhere in this report and in our Annual Report on Form 10-K for the year ended December 31, 2008. These factors are not necessarily all the important factors that could affect us. Unpredictable or unknown factors we have not discussed in this report or in our Annual Report on Form 10-K for the year ended December 31, 2008 could also have material adverse effect on actual results of matters that are the subject of our forward-looking statements. All forward-looking statements speak only as the date on which they are made and we undertake no duty to update or revise any forward-looking statements. We advise our shareholders that they should (1) be aware that important factors not referred to above could affect the accuracy of our forward-looking statements and (2) use caution and common sense when considering our forward-looking statements.

### **Company Overview**

Pioneer Drilling Company provides drilling services and production services to independent and major oil and gas exploration and production companies throughout the United States and internationally in Colombia. Our company was incorporated in 1979 as the successor to a business that had been operating since 1968. Our business has grown through acquisitions and through organic growth. Over the last 10 years, we have significantly expanded our drilling rig fleet by adding 35 rigs through acquisitions and by adding 31 rigs through the construction of rigs from new and used components. On March 1, 2008, we significantly expanded our service offerings when we acquired the production services businesses of WEDGE Group Incorporated ("WEDGE") for \$314.7 million and Prairie Investors d/b/a Competition Wireline ("Competition") for \$30.0 million which provide well services, wireline services and fishing and rental services. We funded the WEDGE acquisition primarily with \$311.5 million of borrowings under our secured revolving credit facility. As of October 23, 2009, the senior secured revolving credit facility had an outstanding balance of \$257.5 million, all of which matures in August 2012. Drilling services and production services are fundamental to establishing and maintaining the flow of oil and natural gas throughout the productive life at a well site and enable us to meet multiple needs of our customers.

### **Business Segments**

We currently conduct our operations through two operating segments: our Drilling Services Division and our Production Services Division. The following is a description of these two operating segments. Financial information about our operating segments is included in Note 7, *Segment Information*, of the Notes to Condensed Consolidated Financial Statements, included in Part I, Item 1, *Financial Statements*, of this Quarterly Report on Form 10-Q.

- *Drilling Services Division*—Our Drilling Services Division provides contract land drilling services with its fleet of 71 drilling rigs in the following locations:

<u>Drilling Division Locations</u>	<u>Rig Count</u>
South Texas	17
East Texas	21
North Dakota	7
North Texas	4
Utah	6
Oklahoma	6
Appalachia	3
Colombia / International	7

As of October 23, 2009, 27 drilling rigs are operating under drilling contracts, one of which is earning revenues through early termination fees on its contract with a term that expires in December 2009. We have 38 drilling rigs that are idle and six drilling rigs have been placed in storage or "cold stacked" in our Oklahoma drilling division due to low demand for drilling rigs in that region. We are actively marketing all our idle drilling rigs both domestically and internationally in Latin America. During the second quarter of 2009, we established our Appalachian drilling division and now have three drilling rigs operating in the Marcellus Shale region. We have five drilling rigs located in Colombia that are operating under drilling contracts and



we are marketing two additional drilling rigs for international expansion in Latin America. In addition to our drilling rigs, we provide the drilling crews and most of the ancillary equipment needed to operate our drilling rigs. We obtain our contracts for drilling oil and natural gas wells either through competitive bidding or through direct negotiations with customers. Our drilling contracts generally provide for compensation on either a daywork, turnkey or footage basis. Contract terms generally depend on the complexity and risk of operations, the on-site drilling conditions, the type of equipment used and the anticipated duration of the work to be performed.

- *Production Services Division*—Our Production Services Division provides a broad range of well services to oil and gas drilling and producing companies, including workover services, wireline services, and fishing and rental services. Our production services operations are managed regionally and are concentrated in the major United States onshore oil and gas producing regions in the Gulf Coast, Mid-Continent, Rocky Mountain and Appalachian states. We provide our services to a diverse group of oil and gas companies. The primary production services we offer are the following:
  - *Well Services.* Existing and newly-drilled wells require a range of services to establish and maintain production over their useful lives. We use our fleet of 74 workover rigs in seven division locations to provide these required services, including maintenance of existing wells, workover of existing wells, completion of newly-drilled wells, and plugging and abandonment of wells at the end of their useful lives. We have a premium workover rig fleet consisting of sixty-nine 550 horsepower rigs, four 600 horsepower rigs, and one 400 horsepower rig. As of October 23, 2009, 65 workover rigs have crews assigned and are either operating or are being actively marketed. The remaining nine workover rigs in our fleet are idle with no crews assigned.
  - *Wireline Services.* In order for oil and gas companies to better understand the reservoirs they are drilling or producing, they require logging services to accurately characterize reservoir rocks and fluids. When a producing well is completed, they also must perforate the production casing to establish a flow path between the reservoir and the wellbore. We use our fleet of 61 truck mounted wireline units in 19 division locations to provide these important logging and perforating services. We provide both open and cased-hole logging services, including the latest pulsed-neutron technology. In addition, we provide services which allow oil and gas companies to evaluate the integrity of wellbore casing, recover pipe, or install bridge plugs.
  - *Fishing and Rental Services.* During drilling operations, oil and gas companies are often required to rent unique equipment such as power swivels, foam air units, blow-out preventers, air drilling equipment, pumps, tanks, pipe, tubing, and fishing tools. We have approximately \$15 million of fishing and rental tools that we provide out of four locations in Texas and Oklahoma.

Pioneer Drilling Company's corporate office is located at 1250 N.E. Loop 410, Suite 1000, San Antonio, Texas 78209. Our phone number is (210) 828-7689 and our website address is [www.pioneerdrilg.com](http://www.pioneerdrilg.com). We make available free of charge though our website our Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K, and all amendments to those reports as soon as reasonably practicable after such material is electronically filed with the Securities and Exchange Commission (the "SEC"). Information on our website is not incorporated into this report or otherwise made part of this report.

### ***Market Conditions in Our Industry***

Since late 2008, there has been substantial volatility and a decline in oil and natural gas prices due to the deteriorating global economic environment. In addition, there has been substantial uncertainty in the capital markets and access to financing is uncertain. These conditions have adversely affected our business environment. Our customers have curtailed their drilling programs and reduced their production activities, which has resulted in a decrease in demand for drilling and production services and a reduction in day rates and utilization. In addition, certain of our customers could experience an inability to pay suppliers in the event they are unable to access the capital markets to fund their business operations.

Demand for oilfield services offered by our industry is a function of our customers' willingness to make operating and capital expenditures to explore for, develop and produce hydrocarbons, which in turn is affected by current and expected levels of oil and natural gas prices. From 2004 through 2008, domestic exploration and production spending increased as oil and natural gas prices increased. In response to the significant decline in oil and natural gas prices and the deteriorating global economic environment in late 2008, exploration and production companies announced cuts in their exploration budgets for 2009. These reductions in oil and gas exploration budgets resulted in a reduction in our rig utilization and revenue rates on new contracts during the nine months ended September 30, 2009. Rig utilization and revenue rates are expected to remain at depressed levels for the remainder of 2009. In addition, we may experience a shift to more turnkey and footage drilling contracts from daywork drilling contracts. For additional information concerning the effects of the volatility in oil and gas prices and uncertainty in capital markets, see Item 1A—"Risk Factors" in Part I of our Annual Report on Form 10-K for the year ended December 31, 2008.

On October 23, 2009 the spot price for West Texas Intermediate crude oil was \$80.05, the spot price for Henry Hub natural gas was \$4.89 and the Baker Hughes land rig count was 1,003, a 46% decrease from 1,867 on October 24, 2008. The table below presents average weekly spot prices of West Texas Intermediate crude oil and Henry Hub natural gas, the average weekly domestic land rig count per the Baker Hughes land rig count, and the average monthly domestic workover rig count for the nine months ended September 30, 2009, and each of the previous five years ended September 30, 2009:

	Nine Months Ended September 30, 2009	Years ended September 30,				
		2009	2008	2007	2006	2005
Oil (West Texas Intermediate)	\$ 57.29	\$57.38	\$108.31	\$64.87	\$66.19	\$53.72
Natural Gas (Henry Hub)	\$ 3.77	\$ 4.39	\$ 8.96	\$ 6.85	\$ 7.97	\$ 7.36
U.S. Land Rig Count	1,029	1,226	1,764	1,646	1,479	1,203
U.S. Workover Rig Count	1,777	1,965	2,499	2,383	2,334	2,172

Increased expenditures for exploration and production activities generally lead to increased demand for our drilling services and production services. Over the past several years until late 2008, rising oil and natural gas prices and the corresponding increase in onshore oil and natural gas exploration and production spending led to expanded drilling and well service activity as reflected by the increases in the U.S. land rig counts and U.S. workover rig counts as noted in the table above. The decline in oil and natural gas prices since late 2008 has led to decreased oil and natural gas exploration and production spending and a corresponding decrease in drilling and well services activities as reflected by the decrease in the U.S. land rig counts and the U.S. workover rig counts as noted in the table above.

Exploration and production spending is generally categorized as either a capital expenditure or an operating expenditure. Activities designed to add hydrocarbon reserves are classified as capital expenditures, while those associated with maintaining or accelerating production are categorized as operating expenditures. Our business is influenced substantially by both operating and capital expenditures by exploration and production companies.

Capital expenditures by oil and gas companies tend to be relatively sensitive to volatility in oil or natural gas prices because project decisions are tied to a return on investment spanning a number of years. As such, capital expenditure economics often require the use of commodity price forecasts which may prove inaccurate in the amount of time required to plan and execute a capital expenditure project (such as the drilling of a deep well). When commodity prices are depressed for even a short period of time, capital expenditure projects are routinely deferred until prices return to an acceptable level.

In contrast, both mandatory and discretionary operating expenditures are more stable than capital expenditures for exploration. Mandatory operating expenditure projects involve activities that cannot be avoided in the short term, such as regulatory compliance, safety, contractual obligations and certain projects to maintain the well and related infrastructure in operating condition. Discretionary operating expenditure projects may not be critical to the short-term viability of a lease or field, but these projects are less sensitive to commodity price volatility as compared to capital expenditures for exploration. Discretionary operating expenditure work is evaluated according to a simple short-term payout criterion which is far less dependent on commodity price forecasts.

### Strategy

In past years, our strategy was to become a premier land drilling company through steady and disciplined growth. We executed this strategy by acquiring and building a high quality drilling rig fleet that operates in active drilling markets in the United States. Our long-term strategy is to maintain and leverage our position as a leading land drilling company and evolve into a premier multi-service, international oilfield services provider. The key elements of this long-term strategy include:

- *Expand our Operations into International Markets*—In early 2007, we announced our intention to expand internationally and began negotiating drilling contracts in Colombia. We currently have five drilling rigs located in Colombia that are operating under drilling contracts and we are marketing two additional drilling rigs for international expansion in Latin America.

- *Pursue Opportunities into Other Oilfield Services*—We strive to mitigate the cyclical risk in oilfield services by complementing our drilling services with certain production services. Effective March 1, 2008, we acquired the production services businesses of WEDGE and Competition which provide well services, wireline services and fishing and rental services. We now have a fleet of 74 workover rigs, 61 wireline units and approximately \$15 million of fishing and rental tools equipment that operate out of facilities in Texas, Kansas, North Dakota, Colorado, Utah, Montana, Pennsylvania, Louisiana and Oklahoma. We expanded our Production Services Division with the acquisitions of Paltec, Inc. (Paltec) in August 2008 and Pettus Well Service (Pettus) in October 2008, both operating in Texas.
- *Continue Growth with Select Capital Deployment*—We intend to continue growing our business by making selective acquisitions, continuing new-build programs and / or upgrading our existing assets. Our capital investment decisions are determined by strategic fit and an analysis of the projected return on capital employed on each of those alternatives. During the second quarter of 2009, we established our Appalachian drilling division and now have three drilling rigs operating in the Marcellus Shale region. We completed construction of a 2000 horsepower drilling rig that began operations in June 2009 in our North Dakota drilling division under a contract with a three year term. In addition, we opened four new wireline locations in 2009 and we took delivery of two new wireline units during the first quarter of 2009.

With the declines in oil and natural gas prices due to the deteriorating global economic environment since late 2008 and the reductions in our rig utilization and revenue rates on new contracts in 2009, our near-term strategy is focused on maintaining adequate liquidity. Management has initiated certain cost reduction measures including workforce and wage rate reductions that will reduce operating expenses during the downturn in the industry cycle. Budgeted capital expenditures for 2009 represent routine capital expenditures necessary to keep our equipment in safe and efficient working order and discretionary capital expenditures of new equipment or upgrades of existing equipment when necessary to obtain new contracts. In addition, our marketing initiatives are focused on identifying regional opportunities and evaluating more turnkey drilling contract opportunities. We believe this near-term strategy will position us to take advantage of business opportunities and continue our long-term growth strategy.

## Liquidity and Capital Resources

### *Sources of Capital Resources*

Our principal sources of liquidity consist of: (i) cash and cash equivalents (which equaled \$53.3 million as of September 30, 2009); (ii) cash generated from operations; and (iii) the unused portion of our senior secured revolving credit facility which has borrowing availability of \$56.0 million as of October 23, 2009. On February 29, 2008, we entered into a credit agreement with Wells Fargo Bank, N.A. and a syndicate of lenders (the “Initial Credit Agreement”). On October 5, 2009, we entered into a First Amendment to the Initial Credit Agreement (the “Amended Credit Agreement”). There are no limitations on our ability to access the full borrowing availability under the senior secured revolving credit facility other than maintaining compliance with the covenants in the Amended Credit Agreement. Additional information regarding these covenants is provided in the *Debt Requirements* section below. Our principal liquidity requirements have been for working capital needs, capital expenditures and acquisitions. In addition, when appropriate, we may consider equity or debt offerings to meet our liquidity needs.

*Initial Credit Agreement*—The Initial Credit Agreement provided for a senior secured revolving credit facility, with sub-limits for letters of credit and swing-line loans, of up to an aggregate principal amount of \$400 million, all of which would have matured on February 28, 2013. The Initial Credit Agreement contained customary mandatory prepayments in respect of asset dispositions, debt incurrences and equity issuances which prepayments were applied to reduce outstanding revolving and swing-line loans and letter of credit exposure without a permanent reduction of commitments. Our obligations under the Initial Credit Agreement were secured by substantially all of our domestic assets (excluding any equity interests in, and any assets of, Pioneer Global Holdings, Inc. and its subsidiaries which are the entities that comprise our international operations) and were guaranteed by certain of our domestic subsidiaries (excluding Pioneer Global Holdings, Inc.). Borrowings under the Initial Credit Agreement bore interest, at our option, at the bank prime rate or at the LIBOR rate, plus an applicable per annum margin in each case. The applicable per annum margin was determined based upon our leverage ratio in accordance with a pricing grid in the Initial Credit Agreement. The per annum margin for LIBOR rate borrowings ranged from 1.50% to 2.50% and the per annum margin for bank prime rate borrowings ranged from 0.50% to 1.50%. The LIBOR margin and bank prime rate margin in effect at September 30, 2009 were 2.00% and 1.00%, respectively. A commitment fee was due quarterly based on the average daily unused amount of the commitments of the lenders under the Initial Credit Agreement. In addition, a fronting fee was due for each letter of credit issued and a quarterly letter of credit fee was due based on the average undrawn amount of letters of credit outstanding during such period. Borrowings under the Initial Credit Agreement were used to fund the WEDGE acquisition and were available for acquisitions, working capital and other general corporate purposes.

*Amended Credit Agreement*—Effective October 5, 2009, our Amended Credit Agreement provides for a senior secured revolving credit facility, with sub-limits for letters of credit and swing-line loans, of up to an aggregate principal amount of \$325 million, all of which mature on August 31, 2012. The Amended Credit Agreement contains customary mandatory prepayments in respect of asset dispositions, debt incurrences and equity issuances, and commencing with the fiscal year ending December 31, 2009, if the senior consolidated leverage ratio is greater than 2.50 to 1.00 at the end of any fiscal year, the Amended Credit Agreement requires mandatory prepayments equal to 50% of our excess cash flows. Borrowings and commitments under the Amended Credit



Agreement will be reduced concurrently with the application of certain mandatory prepayments by the amount of such mandatory prepayment. The aggregate availability under the Amended Credit Agreement shall in no event be required to be reduced to less than \$200,000,000 as a result of such mandatory prepayments. Our obligations under the Amended Credit Agreement are secured by substantially all of our domestic assets (including equity interests in Pioneer Global Holdings, Inc. and 65% of the outstanding equity interests of any first-tier foreign subsidiaries owned by Pioneer Global Holdings, Inc., but excluding any equity interest in, and any assets of, Pioneer Services Holdings, LLC) and are guaranteed by certain of our domestic subsidiaries, including Pioneer Global Holdings, Inc. Borrowings under the Amended Credit Agreement bear interest, at our option, at the bank prime rate or at the LIBOR rate, plus an applicable per annum margin in each case. The applicable per annum margin is determined based upon our leverage ratio in accordance with a pricing grid in the Amended Credit Agreement. The per annum margin for LIBOR rate borrowings ranges from 3.50% to 6.00% and the per annum margin for bank prime rate borrowings ranges from 2.50% to 5.00%. The LIBOR margin and bank prime rate margin in effect at October 23, 2009 are 3.5% and 2.5%, respectively. A commitment fee is due quarterly based on the average daily unused amount of the commitments of the lenders under the Amended Credit Agreement. In addition, a fronting fee is due for each letter of credit issued and a quarterly letter of credit fee is due based on the average undrawn amount of letters of credit outstanding during such period. Borrowings under the Amended Credit Agreement are available for acquisitions, working capital and other general corporate purposes. Additional information regarding capital expenditure restrictions under the Amended Credit Agreement is provided in the *Debt Requirements* section below.

At September 30, 2009, we held \$15.9 million (par value) of investments comprised of tax exempt, auction rate preferred securities (“ARPSs”), which are variable-rate preferred securities and have a long-term maturity with the interest rate being reset through “Dutch auctions” that are held every 7 days. The ARPSs have historically traded at par because of the frequent interest rate resets and because they are callable at par at the option of the issuer. Interest is paid at the end of each auction period. Our ARPSs are AAA/Aaa rated securities, collateralized by municipal bonds and backed by assets that are equal to or greater than 200% of the liquidation preference. Until February 2008, the auction rate securities market was highly liquid. Beginning mid-February 2008, we experienced several “failed” auctions, meaning that there was not enough demand to sell all of the securities that holders desired to sell at auction. The immediate effect of a failed auction is that such holders cannot sell the securities at auction and the interest rate on the security resets to a maximum auction rate. We have continued to receive interest payments on our ARPSs in accordance with their terms. Unless a future auction is successful or the issuer calls the security pursuant to redemption prior to maturity, we may not be able to access the funds we invested in our ARPSs without a loss of principal. We have no reason to believe that any of the underlying municipal securities that collateralize our ARPSs are presently at risk of default. We believe we will ultimately recover the par value of the ARPS without loss, primarily due to the collateral securing the ARPSs and our estimate of the discounted cash flows that we expect to collect. We do not currently intend to sell our ARPSs at a loss. Also, we believe it is more-likely-than-not that we will not have to sell our ARPS prior to recovery, since our liquidity needs are expected to be met with cash flows from operating activities and our senior secured revolving credit facility. Our ARPSs are designated as available-for-sale and are reported at fair market value with the related unrealized gains or losses, included in accumulated other comprehensive income (loss), net of tax, a component of shareholders’ equity. The estimated fair value of our ARPSs at September 30, 2009 was \$12.7 million compared with a par value of \$15.9 million. The \$3.2 million difference represents a fair value discount due to the current lack of liquidity which is considered temporary and has been recorded as an unrealized loss, net of tax, in accumulated other comprehensive income (loss). There was no portion of the fair value discount attributable to credit losses. We would recognize an impairment charge in our statement of operations if the fair value of our investments falls below the cost basis and is judged to be other-than-temporary or is judged to be attributable to credit losses. Our ARPSs are classified with other long-term assets on our condensed consolidated balance sheet as of September 30, 2009 because of our inability to determine the recovery period of our investments.

#### *Uses of Capital Resources*

For the nine months ended September 30, 2009, we had \$64.5 million of additions to our property and equipment. For the remainder of fiscal year 2009, our budgeted capital expenditures are approximately \$35.0 million, comprised of new rig and equipment expenditures of approximately \$1.5 million, routine capital expenditures of approximately \$12.0 million, and non-routine capital expenditures of approximately \$21.5 million. We expect to fund these capital expenditures primarily from operating cash flow in excess of our working capital and other normal cash flow requirements and availability under our senior secured revolving credit facility. In addition, when appropriate, we may consider equity or debt offerings to meet our liquidity needs. Based on our near-term strategy to maintain adequate liquidity, budgeted capital expenditures for 2009 represent routine capital expenditures necessary to keep our equipment in safe and efficient working order and discretionary capital expenditures of new equipment or upgrades of existing equipment when necessary to obtain new contracts.

#### *Working Capital*

Our working capital was \$73.0 million at September 30, 2009, compared to \$64.4 million at December 31, 2008. Our current ratio, which we calculate by dividing our current assets by our current liabilities, was 2.1 at September 30, 2009 compared to 1.8 at December 31, 2008.

Our operations have historically generated cash flows sufficient to meet our requirements for debt service and normal capital expenditures. However, during periods when higher percentages of our drilling contracts are turnkey and footage contracts, our short-

term working capital needs could increase.

The changes in the components of our working capital were as follows:

	September 30, 2009	December 31, 2008	Change
Cash and cash equivalents	\$ 53,305	\$ 26,821	\$ 26,484
Receivables			
Trade, net	31,293	76,176	(44,883)
Insurance recoveries	18,363	5,951	12,412
Income taxes	11,164	5,034	6,130
Unbilled	10,008	12,262	(2,254)
Deferred income taxes	4,336	6,270	(1,934)
Inventory	4,855	3,874	981
Prepaid expenses and other current	3,250	8,902	(5,652)
Current assets	<u>136,574</u>	<u>145,290</u>	<u>(8,716)</u>
Accounts payable	16,680	21,830	(5,150)
Current portion of long-term debt	2,093	17,298	(15,205)
Prepaid drilling contracts	—	1,171	(1,171)
Accrued expenses:			
Payroll and related employee costs	7,517	13,592	(6,075)
Insurance premiums and deductibles	10,178	11,569	(1,391)
Insurance claims and settlements	18,363	5,951	12,412
Other	8,721	9,507	(786)
Current liabilities	<u>63,552</u>	<u>80,918</u>	<u>(17,366)</u>
Working capital	<u>\$ 73,022</u>	<u>\$ 64,372</u>	<u>\$ 8,650</u>

The increase in cash and cash equivalents was primarily due to cash provided by operations of \$110.3 million offset by \$67.1 million of property and equipment expenditures and \$17.1 million of debt payments.

The decreases in our trade receivables and unbilled revenues as of September 30, 2009 as compared to December 31, 2008 were primarily due to the decrease in revenues of \$96.3 million, or 56%, for the quarter ended September 30, 2009 as compared to the quarter ended December 31, 2008.

The increases in both our receivables—insurance recoveries and accrued expenses—insurance claims and settlements as of September 30, 2009 as compared to December 31, 2008 are primarily due to lawsuit settlement costs that are payable by our insurance carriers. We settled a lawsuit in July 2009 for \$16.0 million, all but \$1.0 million of which will be covered by our insurance carriers. As of September 30, 2009, we have paid \$1.0 million and our insurance carriers have paid another \$1.0 million of the lawsuit settlement obligation. Our insurance carriers will pay the remaining \$14.0 million of the settlement obligation in installments from October 2009 through December 2009. These settlement costs are reflected on our condensed consolidated balance sheet at September 30, 2009 as \$14.0 million of accrued expenses – insurance claims and settlements with an offsetting \$14.0 million reflected as receivables—insurance recoveries.

The increase in our income taxes receivable as of September 30, 2009 as compared to December 31, 2008 is primarily due to net operating losses realized during 2009.

The decrease in prepaid expenses and other current assets at September 30, 2009 as compared to December 31, 2008 is primarily due to a decrease in prepaid insurance. We renew and prepay most of our insurance premiums in late October of each year and some in April of each year. As of September 30, 2009, we had amortization of eleven of these October insurance premiums, as compared to two months of amortization as of December 31, 2008. In addition, prepaid expenses and other current assets decreased by \$0.9 million relating to funds held in a trust account that were distributed to our former Chief Financial Officer on March 3, 2009 in accordance with the terms of the severance agreement.

The decrease in accounts payable at September 30, 2009 as compared to December 31, 2008 is due to the decline in demand for drilling, workover, wireline and fishing and rental services during the quarter ended September 30, 2009 as compared to the quarter ended December 31, 2008, which resulted in decreased purchases from vendors.

The outstanding balance under our senior secured credit facility is not due until maturity on August 31, 2012. However, when cash and working capital is sufficient, we may make principal payments to reduce the outstanding debt balance prior to maturity. The current portion of long-term debt at December 31, 2008 included principal payments of \$15 million that were made after December 31, 2008 to reduce the outstanding balance of our senior secured revolving credit facility. We have not made any principal payments to reduce the outstanding balance of our senior secured revolving credit facility after September 30, 2009. Therefore, no portion of the outstanding balance of our senior secured revolving credit facility is included in the current portion of long-term debt at September 30, 2009. The current portion of long-term debt at September 30, 2009 relates to \$2.1 million of debt payments under our subordinated notes payable and other debt that are due within the next year.

Prepaid drilling contracts represent amounts billed for mobilization revenues in excess of revenue recognized for certain drilling contracts in Colombia. Mobilization billings, and costs incurred for the mobilization, are deferred and recognized over the term of the related drilling contracts. As of September 30, 2009, the initial terms of these drilling contracts had concluded and all associated mobilization revenues had been recognized.

The decrease in accrued payroll and related employee costs was primarily due to a decrease of \$3.6 million in accrued employee bonuses as of September 30, 2009, as compared to December 31, 2008. Annual employee bonuses for the year ended December 31, 2008 were paid in early March 2009. The remaining portion of the decrease in accrued payroll and related employee costs is primarily due to workforce reductions that occurred during the nine months ended September 30, 2009.

The decrease in accrued expenses – insurance premiums and deductibles at September 30, 2009 as compared to December 31, 2008 is due to the declines in our Drilling Services and Production Services utilization and the resulting reduced workforce during the quarter ended September 30, 2009 as compared to the quarter ended December 31, 2008. The reduction in our workforce lead to fewer workers compensation claims which reduced our obligations for the deductibles under these insurance policies.

The decrease in accrued expenses – other at September 30, 2009 as compared to December 31, 2008 is primarily due to decreases in professional fee accruals and property tax accruals. We accrue property taxes throughout the year and make most of our required property tax payments in January.

#### *Long-Term Debt*

Long-term debt as of September 30, 2009 consists of the following (amounts in thousands):

Senior secured credit facility	\$257,500
Subordinated notes payable	4,587
Other	265
	<u>262,352</u>
Less current portion	<u>(2,093)</u>
	<u>\$260,259</u>

### Contractual Obligations

The following table includes all our contractual obligations of the types specified below at September 30, 2009 (amounts in thousands):

Contractual Obligations	Payments Due by Period				
	Total	Less than 1 year	2-3 years	4-5 years	More than 5 years
Long-term debt	\$262,352	\$ 2,093	\$259,609	\$ 650	\$ —
Interest on long-term debt	28,917	10,038	18,834	45	—
Purchase obligations	15,973	15,973	—	—	—
Operating leases	6,493	2,042	2,908	1,531	12
Restricted cash obligation	2,600	650	1,300	650	—
Other	100	100	—	—	—
<b>Total</b>	<b>\$316,435</b>	<b>\$ 30,896</b>	<b>\$282,651</b>	<b>\$ 2,876</b>	<b>\$ 12</b>

Long-term debt consists of \$257.5 million outstanding under our senior secured credit facility, \$4.6 million outstanding under subordinated notes payable to certain employees that are former shareholders of previously acquired production services businesses and other debt of \$0.3 million. The outstanding balance under our senior secured credit facility is not due until maturity on August 31, 2012 as provided in the Amended Credit Agreement. We may make principal payments to reduce the outstanding debt balance prior to maturity when cash and working capital is sufficient.

Interest payment obligations on our senior secured credit facility are estimated based on interest rates that are in effect on October 23, 2009 and the remaining principal balance of \$257.5 million to be paid at maturity in August 2012. Interest payment obligations on our subordinated notes payable are based on interest rates ranging from 5.4% to 14%, with quarterly payments of principal and interest and final maturity dates ranging from November 2010 to March 2013.

Purchase obligations primarily relate to drilling rig and well servicing rig upgrades, acquisitions or new construction.

Operating leases consist of lease agreements with terms in excess of one year for office space, operating facilities, equipment and personal property.

As of September 30, 2009, we had restricted cash in the amount of \$2.6 million held in an escrow account to be used for future payments in connection with the acquisition of Competition. The former owner of Competition will receive annual installments of \$0.7 million payable over a five year term from the escrow account.

### Debt Requirements

The financial covenants contained in our Initial Credit Agreement and Amended Credit Agreement include the following:

- A maximum total consolidated leverage ratio that cannot exceed:
  - 2.75 to 1.00 as of the end of the fiscal quarter ended September 30, 2009;
  - 4.25 to 1.00 as of the end of the fiscal quarter ending December 31, 2009;
  - 5.00 to 1.00 as of the end of any fiscal quarter ending March 31, 2010 through June 30, 2011;
  - 4.75 to 1.00 as of the end of the fiscal quarter ending September 30, 2011;
  - 4.50 to 1.00 as of the end of the fiscal quarter ending December 31, 2011;
  - 4.25 to 1.00 as of the end of the fiscal quarter ending March 31, 2012; and
  - 4.00 to 1.00 as of the end of any fiscal quarter ending June 30, 2012 and thereafter.
- A maximum senior consolidated leverage ratio, which excludes unsecured and subordinated debt, that cannot exceed:
  - 4.25 to 1.00 as of the end of the fiscal quarter ending December 31, 2009;
  - 5.00 to 1.00 as of the end of the fiscal quarters ending March 31, 2010 and June 30, 2010;
  - 4.75 to 1.00 as of the end of the fiscal quarter ending September 30, 2010;
  - 4.50 to 1.00 as of the end of the fiscal quarter ending December 31, 2010;
  - 4.25 to 1.00 as of the end of the fiscal quarter ending March 31, 2011;
  - 4.00 to 1.00 as of the end of the fiscal quarter ending June 30, 2011;

- 3.75 to 1.00 as of the end of the fiscal quarter ending September 30, 2011;
- 3.50 to 1.00 as of the end of the fiscal quarter ending December 31, 2011;
- 3.25 to 1.00 as of the end of the fiscal quarter ending March 31, 2012; and
- 3.00 to 1.00 as of the end of any fiscal quarter ended June 30, 2012 and thereafter.
- A minimum interest coverage ratio that cannot be less than:
  - 3.00 to 1.00 as of the end of the fiscal quarters ending September 30, 2009 and December 31, 2009;
  - 2.00 to 1.00 as of the end of any fiscal quarter ending March 31, 2010 through December 31, 2011; and
  - 3.00 to 1.00 as of the end of any fiscal quarter ending March 31, 2012 and thereafter.
- If our senior consolidated leverage ratio is greater than 2.25 to 1.00 at the end of any fiscal quarter, a minimum asset coverage ratio that cannot be less than 1.25 to 1.00 for the quarter ended September 30, 2009 (as provided in our Initial Credit Agreement) and a minimum asset coverage ratio that cannot be less than 1.00 to 1.00 for any fiscal quarter ending on or before December 31, 2011, and 1.10 to 1.00 for any fiscal quarter ending March 31, 2012 and thereafter (as provided in the Amended Credit Agreement). If our senior consolidated leverage ratio is greater than 2.25 to 1.00 and our asset coverage ratio is less than 1.00 to 1.00, then borrowings outstanding under the Amended Credit Agreement will be limited to the sum of 80% of eligible accounts receivable, 80% of the orderly liquidation value of eligible equipment and 40% of the net book value of certain other fixed assets.

The Amended Credit Agreement restricts capital expenditures unless (a) after giving effect to such capital expenditure, no event of default would exist under the Amended Credit Agreement and availability under the Amended Credit Agreement would be equal to or greater than \$25 million and (b) if the senior consolidated leverage ratio as of the last day of the most recent reported fiscal quarter was equal to or greater than 2.50 to 1.00, such capital expenditure would not cause the sum of all capital expenditures to exceed:

- \$52 million for the second half of fiscal year 2009;
- \$65 million for fiscal year 2010; and
- \$80 million for each fiscal year thereafter.

The capital expenditure thresholds for each period noted above may be increased by:

- the first \$25 million of any aggregate equity issuance proceeds received during such period and 25% of any equity issuance proceeds received in excess of \$25 million during such period; and
- 25% of any debt incurrence proceeds received during such period.

In addition, any unused portion of the capital expenditure threshold up to \$30 million can be carried over from the immediate preceding fiscal year.

At September 30, 2009, we were in compliance with our financial covenants. Our total consolidated leverage ratio was 2.32 to 1.00, our interest coverage ratio was 13.08 to 1.00 and our asset coverage ratio was 1.39 to 1.00. The senior consolidated leverage ratio was not a part of our Initial Credit Agreement so it was not applicable at September 30, 2009. The Amended Credit Agreement has additional restrictive covenants that, among other things, limit the incurrence of additional debt, investments, liens, dividends, acquisitions, redemptions of capital stock, prepayments of indebtedness, asset dispositions, mergers and consolidations, transactions with affiliates, hedging contracts, sale leasebacks and other matters customarily restricted in such agreements. In addition, the Amended Credit Agreement contains customary events of default, including without limitation, payment defaults, breaches of representations and warranties, covenant defaults, cross-defaults to certain other material indebtedness in excess of specified amounts, certain events of bankruptcy and insolvency, judgment defaults in excess of specified amounts, failure of any guaranty or security document supporting the credit agreement and change of control.

## Results of Operations

Effective March 1, 2008, we acquired the production services businesses of WEDGE and Competition which provide well services, wireline services and fishing and rental services. The acquisitions of the production services businesses of WEDGE and Competition resulted in the formation of our new operating segment, the Production Services Division. We consolidated the results of these acquisitions from the day they were acquired. These acquisitions affect the comparability from period to period of our historical results, and our historical results may not be indicative of our future results.

### Statement of Operations Analysis

The following table provides information for our operations for the three and nine months ended September 30, 2009 and 2008 (amounts in thousands, except average number of drilling rigs, utilization rate and revenue days information):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2009	2008	2009	2008
<b>Drilling Services Division:</b>				
Revenues	\$48,084	\$124,297	\$165,170	\$333,587
Operating costs	<u>35,315</u>	<u>70,342</u>	<u>107,880</u>	<u>198,115</u>
Drilling Services Division margin	<u>\$12,769</u>	<u>\$ 53,955</u>	<u>\$ 57,290</u>	<u>\$135,472</u>
Average number of drilling rigs	71.0	67.7	70.6	67.1
Utilization rate	35%	96%	41%	90%
Revenue days	2,271	6,017	7,805	16,528
Average revenues per day	\$21,173	\$ 20,658	\$ 21,162	\$ 20,183
Average operating costs per day	<u>15,550</u>	<u>11,691</u>	<u>13,822</u>	<u>11,987</u>
Drilling Services Division margin per day	<u>\$ 5,623</u>	<u>\$ 8,967</u>	<u>\$ 7,340</u>	<u>\$ 8,196</u>
<b>Production Services Division:</b>				
Revenues	\$26,282	\$ 49,948	\$ 79,156	\$106,602
Operating costs	<u>16,638</u>	<u>25,025</u>	<u>50,260</u>	<u>53,871</u>
Production Services Division margin	<u>\$ 9,644</u>	<u>\$ 24,923</u>	<u>\$ 28,896</u>	<u>\$ 52,731</u>
<b>Combined</b>				
Revenues	\$74,366	\$174,245	\$244,326	\$440,189
Operating costs	<u>51,953</u>	<u>95,367</u>	<u>158,140</u>	<u>251,986</u>
Combined margin	<u>\$22,413</u>	<u>\$ 78,878</u>	<u>\$ 86,186</u>	<u>\$188,203</u>
EBITDA	<u>\$15,152</u>	<u>\$ 64,747</u>	<u>\$ 60,876</u>	<u>\$154,318</u>

We present Drilling Services Division margin, Production Services Division margin, combined margin and earnings before interest, taxes, depreciation and amortization (EBITDA) information because we believe it provides investors and our management additional information to assist them in assessing our business and performance in comparison to other companies in our industry. Since Drilling Services Division margin, Production Services Division margin, combined margin and EBITDA are “non-GAAP” financial measure under the rules and regulations of the SEC, we are providing the following reconciliation of combined margin and EBITDA to net (loss) earnings, which is the nearest comparable GAAP financial measure.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2009	2008	2009	2008
(amounts in thousands)				
Reconciliation of combined margin and EBITDA to net (loss) earnings:				
Combined margin	\$ 22,413	\$ 78,878	\$ 86,186	\$ 188,203
Selling, general and administrative	(8,892)	(12,840)	(27,870)	(32,712)
Bad debt recovery (expense)	1,409	260	1,713	216
Other (expense) income	222	(1,551)	847	(1,389)
EBITDA	15,152	64,747	60,876	154,318
Depreciation and amortization	(26,952)	(24,225)	(78,467)	(61,924)
Interest expense, net	(1,796)	(3,568)	(5,373)	(8,617)
Income tax benefit (expense)	4,406	(12,760)	8,133	(28,619)
Net (loss) earnings	<u>\$ (9,190)</u>	<u>\$ 24,194</u>	<u>\$(14,831)</u>	<u>\$ 55,158</u>

Our Drilling Services Division's revenues decreased by \$76.2 million, or 61%, for the quarter ended September 30, 2009, as compared to the corresponding quarter in 2008, due to a 62% decrease in revenue days that resulted from a decline in our rig utilization rate from 96% to 35%. In contrast to the decrease in our Drilling Services Division's revenues, our average contract drilling revenues per day increased by \$515, or 2%. This increase in average drilling revenues per day is attributable to higher average drilling revenues per day for our Colombian operations which represented a larger portion of our drilling revenues for 2009 as compared to 2008. Our average drilling revenues per day for our domestic operations decreased by 8% for the quarter ended September 30, 2009, since the demand for drilling rigs has decreased during 2009 as compared to 2008. The decrease in our average drilling revenues per day for our domestic operations is less than expected because a significant portion of our domestic drilling rigs were operating or were on standby under longer-term drilling contracts that were entered into when drilling rig demand was high and revenues per day were at historically high levels.

For the nine months ended September 30, 2009, our Drilling Services Division's revenues decreased by \$168.4 million, or 50%, as compared to the corresponding period in 2008, due to a 53% decrease in revenue days that resulted from a decline in our rig utilization rate from 90% to 41%. In contrast to the decrease in our Drilling Services Division's revenues, our average contract drilling revenues per day increased by \$979, or 5%. This increase in average drilling revenues per day is attributable to higher average drilling revenues per day for our Colombian operations which represented a larger portion of our drilling revenues for 2009 as compared to 2008. Our average drilling revenues per day for our domestic operations decreased by 4% for the nine months ended September 30, 2009, since the demand for drilling rigs has decreased during 2009 as compared to 2008. The decrease in our average drilling revenues per day for our domestic operations is less than expected because a significant portion of our domestic drilling rigs were operating or were on standby under longer-term drilling contracts that were entered into when drilling rig demand was high and revenues per day were at historically high levels.

Demand for drilling rigs influences the types of drilling contracts we are able to obtain. As demand for drilling rigs decreases, daywork rates move down and we may switch to performing more turnkey drilling contracts to maintain higher utilization rates and improve our Drilling Services Division's margins. We completed five turnkey drilling contracts during the quarter ended September 30, 2009 as compared to two turnkey drilling contracts completed during the quarter ended September 30, 2008. The following table provides percentages of our drilling revenues by drilling contract type for the three and nine months ended September 30, 2009 and 2008:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2009	2008	2009	2008
Daywork drilling contracts	74%	93%	90%	91%
Turnkey drilling contracts	26%	2%	10%	3%
Footage drilling contracts	—	5%	—	6%

Our Drilling Services Division's operating costs declined by \$35.0 million, or 50%, for the quarter ended September 30, 2009, as compared to the corresponding quarter in 2008, primarily due to a 62% decrease in revenue days that resulted from a decline in our rig utilization rate from 96% to 35%. In contrast to the decrease in our Drilling Services Division's operating costs, our average operating costs per day increased by \$3,859, or 33%, primarily due to higher average drilling costs per day for our Colombian operations which represented a larger portion of our drilling costs for 2009 as compared to 2008. In addition, average operating costs per day increased due to fixed overhead costs associated with division offices, supervisory level employees, insurance and property taxes. Since we had a significant decrease in revenue days, these fixed overhead costs result in an increase in average operating costs

per revenue day.

For the nine months ended September 30, 2009, our Drilling Services Division's operating costs declined by \$90.2 million, or 46%, as compared to the corresponding period in 2008, primarily due to a 53% decrease in revenue days that resulted from a decline in our rig utilization rate from 90% to 41%. In contrast to the decrease in our Drilling Services Division's operating costs, our average operating costs per day increased by \$1,835, or 15%, primarily due to higher average drilling costs per day for our Colombian operations which represented a larger portion of our drilling costs for 2009 as compared to 2008. In addition, average operating costs per day increased due to fixed overhead costs associated with division offices, supervisory level employees, insurance and property taxes. Since we had a significant decrease in revenue days, these fixed overhead costs result in an increase in average operating costs per revenue day.

Our Production Services Division's revenue decreased by \$23.7 million, or 47%, and operating costs decreased by \$8.4 million, or 34%, for the quarter ended September 30, 2009, as compared to the corresponding quarter in 2008, due to lower demand for well services, wireline services and fishing and rental services.

For the nine months ended September 30, 2009, our Production Services Division's revenue decreased by \$27.4 million, or 26%, while operating costs decreased by \$3.6 million, or 7%, as compared to the corresponding nine months in 2008. Our Production Services Division experienced decreases in its revenue and operating cost due to lower demand for well services, wireline services and fishing and rental services during the nine months ended September 30, 2009, as compared to the corresponding period in 2008. This decrease in revenues and operating costs due to lower demand was partially offset by the timing impact of the WEDGE and Competition acquisitions on March 1, 2008 which created our Production Services Division. A full nine months of Production Services Division operations are reflected in the operating results for the nine months ended September 30, 2009, as compared to seven months of operating results for the corresponding period in 2008.

Our selling, general and administrative expense for the quarter ended September 30, 2009 decreased by approximately \$3.9 million, or 31%, as compared to the corresponding quarter in 2008, primarily due to a \$2.1 million decrease in professional and consulting expenses and a \$2.0 million decrease in compensation related expenses related to bonus accrual and workforce reductions. The overall decrease in selling, general and administrative expense was partially offset by increases in insurance expenses.

For the nine months ended September 30, 2009, our selling, general and administrative expense decreased by approximately \$4.8 million, or 15%, as compared to the corresponding period in 2008. Professional and consulting expenses decreased by \$4.2 million and compensation related expenses decreased by \$1.3 million for the nine months ended September 30, 2009, as compared to the corresponding period in 2008. The overall decrease in selling, general and administrative expense was partially offset by increases in insurance expenses and selling, general and administrative expenses relating to our Production Services Division. As noted above, a full nine months of Production Services Division operations are reflected in the results of operations for the nine months ended September 30, 2009, as compared to seven months of operating results for the nine months ended September 30, 2008.

Bad debt recovery increased for the quarter and nine month periods ended September 30, 2009 as compared to the corresponding periods in 2008 primarily due to the collection of a customer's past due account receivable balance for which we had previously established a \$1.3 million allowance for doubtful accounts in December 2008.

Our other income for the quarter ended September 30, 2009 increased by \$1.8 million as compared to the corresponding quarter in 2008, primarily due to foreign currency translation gains and losses relating to our operations in Colombia. We recorded foreign currency translation gains of \$43,000 for the quarter ended September 30, 2009, and foreign currency translation losses of \$1.6 million for the quarter ended September 30, 2008.

For the nine months ended September 30, 2009, our other income increased by \$2.2 million as compared to the corresponding period in 2008, primarily due to foreign currency translation gains and losses relating to our operations in Colombia. We recorded foreign currency translation gains of \$0.3 for the nine months ended September 30, 2009, and foreign currency translation losses of \$1.7 million for the nine months ended September 30, 2008.

Our depreciation and amortization expenses increased by \$2.7 million, or 11%, for the quarter ended September 30, 2009, as compared to the corresponding quarter in 2008. This increase resulted primarily from the increase in the fleet size of our drilling rigs, workover rigs and wireline units. The 2009 additions to each of our fleets mostly consisted of newly constructed equipment.

For the nine months ended September 30, 2009, our depreciation and amortization expenses increased by \$16.5 million, or 27%, as compared to the corresponding period in 2008. This increase resulted primarily from the increase in the fleet size of our drilling rigs, workover rigs and wireline units. The 2009 additions to each fleet consisted primarily of newly constructed equipment. The increase also related to additional depreciation and amortization expense for our new Production Services Division. As noted above, a full nine months of Production Services Division operations are reflected in the results of operations for the nine months ended September 30, 2009, as compared to seven months of operating results for the nine months ended September 30, 2008.

Our interest expense is primarily related to interest due on the amounts outstanding under our senior secured revolving credit facility. Our interest expense decreased \$1.8 million for the quarter ended September 30, 2009, as compared to the corresponding quarter in 2008, and decreased \$3.2 million for the nine months ended September 30, 2009, as compared to the corresponding period in 2008. These decreases are due to reductions in the amounts outstanding under our senior secured revolving credit facility and due to decreases in the LIBOR and bank prime base rates used to determine our effective borrowing rate per our Initial Credit Agreement and Amended Credit Agreement. Borrowings under the senior secured revolving credit facility were first used to fund the acquisitions of the production services businesses of WEDGE and Competition on March 1, 2008. Since operating results for the nine months ended September 30, 2009 reflect a full nine months of interest expense as compared to seven months of interest expense for the nine months ended September 30, 2008, the overall decrease in interest expense for the nine months ended September 30, 2009 is partially offset by an increase in interest expense due to the timing of these borrowings.

Our effective income tax rates for the quarter and nine months periods ended September 30, 2009 differ from the federal statutory rate in the United States of 35% primarily due to pretax income recognized in foreign jurisdictions with a lower effective tax rate, the release of valuation allowance relating to foreign net operating loss carryforwards, state income taxes and other permanent differences.

#### *Inflation*

Due to the increased rig count in each of our market areas over the past several years, availability of personnel to operate our rigs was limited. In April 2005, January 2006, May 2006 and September 2008, we raised wage rates for our drilling rig personnel by an average of 6%, 6%, 14% and 6%, respectively. We were able to pass these wage rate increases on to our customers based on contract terms. In February 2009, we reduced wage rates for drilling rig personnel to offset the wage rate increases from September 2008. In September 2009, we had additional wage rate reductions for drilling rig personnel of approximately 15%.

During the fiscal years ended December 31, 2007 and 2008, we experienced increases in costs for rig repairs and maintenance and costs of rig upgrades and new rig construction, due to the increased industry-wide demand for equipment, supplies and service. We estimate these costs increased by 10% to 15% during the fiscal years ended December 31, 2007 and 2008. We have not experienced similar cost increases during 2009 and do not expect similar cost increases during the remainder of fiscal year ending December 31, 2009.

#### *Off Balance Sheet Arrangements*

We do not currently have any off balance sheet arrangements.

#### *Critical Accounting Policies and Estimates*

*Revenue and cost recognition*—Our Drilling Services Division earns revenues by drilling oil and gas wells for our customers under daywork, turnkey or footage contracts, which usually provide for the drilling of a single well. We recognize revenues on daywork contracts for the days completed based on the dayrate each contract specifies. We recognize revenues from our turnkey and footage contracts on the percentage-of-completion method based on our estimate of the number of days to complete each contract. Individual contracts are usually completed in less than 60 days. The risks to us under a turnkey contract and, to a lesser extent, under footage contracts, are substantially greater than on a contract drilled on a daywork basis. Under a turnkey contract, we assume most of the risks associated with drilling operations that are generally assumed by the operator in a daywork contract, including the risks of blowout, loss of hole, stuck drill pipe, machinery breakdowns and abnormal drilling conditions, as well as risks associated with subcontractors' services, supplies, cost escalations and personnel operations.

Our management has determined that it is appropriate to use the percentage-of-completion method, as defined in the Financial Accounting Standards Board (FASB) Accounting Standards Codification (ASC) Topic 605 (formerly American Institute of Certified Public Accountants' Statement of Position 81-1), to recognize revenue on our turnkey and footage contracts. Although our turnkey and footage contracts do not have express terms that provide us with rights to receive payment for the work that we perform prior to drilling wells to the agreed-on depth, we use this method because, as provided in applicable accounting literature, we believe we achieve a continuous sale for our work-in-progress and believe, under applicable state law, we ultimately could recover the fair value of our work-in-progress even in the event we were unable to drill to the agreed-on depth in breach of the applicable contract. However, in the event we were unable to drill to the agreed-on depth in breach of the contract, ultimate recovery of that value would be subject to negotiations with the customer and the possibility of litigation.

If a customer defaults on its payment obligation to us under a turnkey or footage contract, we would need to rely on applicable law to enforce our lien rights, because our turnkey and footage contracts do not expressly grant to us a security interest in the work we have completed under the contract and we have no ownership rights in the work-in-progress or completed drilling work, except any rights arising under the applicable lien statute on foreclosure. If we were unable to drill to the agreed-on depth in breach of the contract, we also would need to rely on equitable remedies outside of the contract, including quantum meruit, available in applicable courts to recover the fair value of our work-in-progress under a turnkey or footage contract.



We accrue estimated contract costs on turnkey and footage contracts for each day of work completed based on our estimate of the total costs to complete the contract divided by our estimate of the number of days to complete the contract. Contract costs include labor, materials, supplies, repairs and maintenance, operating overhead allocations and allocations of depreciation and amortization expense. In addition, the occurrence of uninsured or under-insured losses or operating cost overruns on our turnkey and footage contracts could have a material adverse effect on our financial position and results of operations. Therefore, our actual results for a contract could differ significantly if our cost estimates for that contract are later revised from our original cost estimates for a contract in progress at the end of a reporting period which was not completed prior to the release of our financial statements.

With most drilling contracts, we receive payments contractually designated for the mobilization of rigs and other equipment. Payments received, and costs incurred for the mobilization services are deferred and recognized on a straight line basis over the contract term of certain drilling contracts. Costs incurred to relocate rigs and other drilling equipment to areas in which a contract has not been secured are expensed as incurred. Reimbursements that we receive for out-of-pocket expenses are recorded as revenue and the out-of-pocket expenses for which they relate are recorded as operating costs.

The asset "unbilled receivables" represents revenues we have recognized in excess of amounts billed on drilling contracts and production services in progress. The asset "prepaid expenses and other current assets" includes deferred mobilization costs for certain drilling contracts. The liability "prepaid drilling contracts" represents deferred mobilization revenues for certain drilling contracts and amounts collected on contracts in excess of revenues recognized.

Our Production Services Division earns revenues for well services, wireline services and fishing and rental services pursuant to master services agreements based on purchase orders, contracts or other persuasive evidence of an arrangement with the customer that include fixed or determinable prices. Production service revenue is recognized when the service has been rendered and collectibility is reasonably assured.

*Long-lived Assets and Intangible Assets*—We evaluate for potential impairment of long-lived assets and intangible assets subject to amortization when indicators of impairment are present, as defined in ASC Topic 360 (formerly SFAS No. 144). Circumstances that could indicate a potential impairment include significant adverse changes in industry trends, economic climate, legal factors, and an adverse action or assessment by a regulator. More specifically, significant adverse changes in industry trends include significant declines in revenue rates, utilization rates, oil and natural gas market prices and industry rig counts for drilling rigs and workover rigs. In performing the impairment evaluation, we estimate the future undiscounted net cash flows relating to long-lived assets and intangible assets grouped at the lowest level that cash flows can be identified. For our Production Services Division, our long-lived assets and intangible assets are grouped at the reporting unit level which is one level below the operating segment level. For our Drilling Services Division, we perform an impairment evaluation and estimate future undiscounted cash flows for individual drilling rig assets. If the sum of the estimated future undiscounted net cash flows is less than the carrying amount of the long-lived assets and intangible assets for these asset grouping levels, then we would recognize an impairment charge. The amount of an impairment charge would be measured as the difference between the carrying amount and the fair value of these assets. The assumptions used in the impairment evaluation for long-lived assets and intangible assets are inherently uncertain and require management judgment.

We performed an impairment analysis of our long-lived assets and intangible assets at December 31, 2008, due to significant adverse changes in the economic and business climate that resulted in decreases in estimated revenues, margins and cash flows. Essentially all our intangible assets were recorded in connection with the acquisitions of the production services businesses from WEDGE, Competition, Pettus and Paltec when revenues, margins and cash flows were at historically high levels earlier in 2008. We determined that the sum of the estimated future undiscounted net cash flows was less than the carrying amount of the long-lived assets and intangible assets in each reporting unit at December 31, 2008. Our long-lived asset and intangible asset impairment analysis for the reporting units in our Production Services Division resulted in no impairment charge to property and equipment and a non-cash impairment charge of \$52.8 million to the carrying value of our intangible assets for customers relationships for the year ended December 31, 2008. For our Drilling Services Division, we did not record an impairment charge on any long-lived assets for the year ended December 31, 2008. The assumptions used in the impairment evaluation for long-lived assets and intangible assets are inherently uncertain and require management judgment. This impairment charge did not have an impact on our liquidity or debt covenants; however, it was a reflection of the overall downturn in our industry and decline in our projected cash flows.

*Goodwill*—Goodwill results from business acquisitions and represents the excess of acquisition costs over the fair value of the net assets acquired. We account for goodwill and other intangible assets under the provisions of ASC Topic 350 (formerly SFAS No. 142). Goodwill is tested for impairment annually as of December 31 or more frequently if events or changes in circumstances indicate that the asset might be impaired. Circumstances that could indicate a potential impairment include a significant adverse change in the economic or business climate, a significant adverse change in legal factors, an adverse action or assessment by a regulator, unanticipated competition, loss of key personnel and the likelihood that a reporting unit or significant portion of a reporting unit will be sold or otherwise disposed of. These circumstances could lead to our net book value exceeding our market capitalization which is another indicator of a potential impairment in goodwill. SFAS No. 142 requires a two-step process for testing impairment. First, the fair value of each reporting unit is compared to its carrying value to determine whether an indication of impairment exists. Goodwill was initially recorded for our Production Services Division operating segment and was allocated to its three reporting units which are well services, wireline services and fishing and rental services. Second, if impairment is indicated, then the fair value of



the reporting unit's goodwill is determined by allocating the unit's fair value to its assets and liabilities (including any unrecognized intangible assets) as if the reporting unit had been acquired in a business combination on the impairment test date. The amount of impairment for goodwill is measured as the excess of the carrying value of the reporting unit over its fair value.

When estimating fair values of a reporting unit for our goodwill impairment test, we use a combination of an income approach and a market approach which incorporates both management's views and those of the market. The income approach provides an estimated fair value based on each reporting unit's anticipated cash flows that are discounted using a weighted average cost of capital rate. The market approach provides an estimated fair value based on our market capitalization that is computed using the 30-day average market price of our common stock and the number of shares outstanding as of the impairment test date. The estimated fair values computed using the income approach and the market approach are then equally weighted and combined into a single fair value. The primary assumptions used in the income approach are estimated cash flows and weighted average cost of capital. Estimated cash flows are primarily based on projected revenues, operating costs and capital expenditures and are discounted based on comparable industry average rates for weighted average cost of capital. We utilized discount rates based on weighted average cost of capital ranging from 15.8% to 16.7% when we estimated fair values of our reporting units as of December 31, 2008. The primary assumptions used in the market approach is the allocation of total market capitalization to each reporting unit, which is based on projected EBITDA percentages for each reporting unit, and control premiums, which are based on comparable industry averages. We utilized a 30% control premium when we estimated fair values of our reporting units as of December 31, 2008. To ensure the reasonableness of the estimated fair values of our reporting units, we performed a reconciliation of our total market capitalization to the total estimated fair value of all our reporting units. The assumptions used in estimating fair values of reporting units and performing the goodwill impairment test are inherently uncertain and require management judgment.

Our common stock price per share declined in market value from \$13.30 at September 30, 2008, to \$5.57 at December 31, 2008, which resulted in our net book value exceeding our market capitalization during most of this time period. We believed the decline in the market price of our common stock resulted from a significant adverse change in the economic and business climate as financial markets reacted to the credit crisis facing major lending institutions and worsening conditions in the overall economy during the fourth quarter of the year ended December 31, 2008. During the same time, there were significant declines in oil and natural gas prices which lead to declines in production service revenues, margins and cash flows. We considered the impact of these significant adverse changes in the economic and business climate as we performed our annual impairment assessment of goodwill as of December 31, 2008. The estimated fair values of our reporting units were negatively impacted by significant reductions in estimated cash flows for the income approach component and a significant reduction in our market capitalization for the market approach component of our fair value estimation process. Our goodwill was initially recorded in connection with the acquisitions of the production services businesses from WEDGE, Competition, Pettus and Paltec, all of which occurred between March 1, 2008 and October 1, 2008, when production service revenues, margins and cash flows and our market capitalization were at historically high levels.

Our goodwill impairment analysis as of December 31, 2008 lead us to conclude that there would be no remaining implied value attributable to our goodwill and accordingly, we recorded a non-cash charge of \$118.6 million to our operating results for the year ended December 31, 2008, for the full impairment of our goodwill. Therefore, we had no remaining goodwill reflected on our consolidated balance sheet as of December 31, 2008. Our goodwill impairment analysis would have lead to the same full impairment conclusion if we increased or decreased our discount rates or control premiums by 10% when estimating the fair values of our reporting units. This impairment charge is not expected to have an impact on our liquidity or debt covenants; however, it is a reflection of the overall downturn in our industry and decline in our projected cash flows.

*Deferred taxes*—We provide deferred taxes for the basis differences in our property and equipment between financial reporting and tax reporting purposes and other costs such as compensation, foreign net operating loss carryforwards, employee benefit and other accrued liabilities which are deducted in different periods for financial reporting and tax reporting purposes. For property and equipment, basis differences arise from differences in depreciation periods and methods and the value of assets acquired in a business acquisition where we acquire an entity rather than just its assets. For financial reporting purposes, we depreciate the various components of our drilling rigs, workover rigs and wireline units over 2 to 25 years and refurbishments over 3 to 5 years, while federal income tax rules require that we depreciate drilling rigs, workover rigs, wireline units and refurbishments over 5 years. Therefore, in the first 5 years of our ownership of a drilling rig, workover rig or wireline unit, our tax depreciation exceeds our financial reporting depreciation, resulting in our providing deferred taxes on this depreciation difference. After 5 years, financial reporting depreciation exceeds tax depreciation, and the deferred tax liability begins to reverse.

*Accounting estimates*—We consider the recognition of revenues and costs on turnkey and footage contracts to be critical accounting estimates. On these types of contracts, we are required to estimate the number of days needed for us to complete the contract and our total cost to complete the contract. Our actual costs could substantially exceed our estimated costs if we encounter problems such as lost circulation, stuck drill pipe or an underground blowout on contracts still in progress subsequent to the release of the financial statements. We receive payment under turnkey and footage contracts when we deliver to our customer a well completed to the depth specified in the contract, unless the customer authorizes us to drill to a more shallow depth. Since 1995, we have completed all our turnkey or footage contracts. Although our initial cost estimates for turnkey and footage contracts do not include cost estimates for risks such as stuck drill pipe or loss of circulation, we believe that our experienced management team, our



knowledge of geologic formations in our areas of operations, the condition of our drilling equipment and our experienced crews have previously enabled us to make reasonable cost estimates and complete contracts according to our drilling plan. While we do bear the risk of loss for cost overruns and other events that are not specifically provided for in our initial cost estimates, our pricing of turnkey and footage contracts takes such risks into consideration. When we encounter, during the course of our drilling operations, conditions unforeseen in the preparation of our original cost estimate, we increase our cost estimate to complete the contract. If we anticipate a loss on a contract in progress at the end of a reporting period due to a change in our cost estimate, we accrue the entire amount of the estimated loss, including all costs that are included in our revised estimated cost to complete that contract, in our consolidated statement of operations for that reporting period. During the nine months ended September 30, 2009, we did not experience a loss on any turnkey and footage contracts completed. We are more likely to encounter losses on turnkey and footage contracts in periods in which revenue rates are lower for all types of contracts. During periods of reduced demand for drilling rigs, our overall profitability on turnkey and footage contracts has historically exceeded our profitability on daywork contracts.

Revenues and costs during a reporting period could be affected for contracts in progress at the end of a reporting period which have not been completed before our financial statements for that period are released. We had no turnkey or footage contracts in progress at September 30, 2009. Our unbilled receivables totaled \$10.0 million at September 30, 2009. Of that amount accrued, \$9.6 million related to the revenue recognized but not yet billed on daywork drilling contracts in progress at September 30, 2009 and \$0.4 million related to unbilled receivables for our Production Services Division.

We estimate an allowance for doubtful accounts based on the creditworthiness of our customers as well as general economic conditions. We evaluate the creditworthiness of our customers based on commercial credit reports, trade references, bank references, financial information, production information and any past experience we have with the customer. Consequently, any change in those factors could affect our estimate of our allowance for doubtful accounts. In some instances, we require new customers to establish escrow accounts or make prepayments. We typically invoice our customers at 15-day intervals during the performance of daywork contracts and upon completion of the daywork contract. Turnkey and footage contracts are invoiced upon completion of the contract. Our typical contract provides for payment of invoices in 10 to 30 days. We generally do not extend payment terms beyond 30 days and have not extended payment terms beyond 90 days for any of our contracts in the last three fiscal years. We had an allowance for doubtful accounts of \$0.3 million at September 30, 2009 and \$1.6 millions at December 31, 2008.

Our determination of the useful lives of our depreciable assets, which directly affects our determination of depreciation expense and deferred taxes is also a critical accounting estimate. A decrease in the useful life of our property and equipment would increase depreciation expense and reduce deferred taxes. We provide for depreciation of our drilling, production, transportation and other equipment on a straight-line method over useful lives that we have estimated and that range from 2 to 25 years. We record the same depreciation expense whether a drilling rig, workover rig or wireline unit is idle or working. Our estimates of the useful lives of our drilling, production, transportation and other equipment are based on our more than 35 years of experience in the oilfield services industry with similar equipment.

As of September 30, 2009, we had foreign deferred tax assets consisting of foreign net operating losses and other tax benefits available to reduce future taxable income in a foreign jurisdiction. In assessing the realizability of our foreign deferred tax assets, we only recognize a tax benefit to the extent of taxable income that we expect to earn in the foreign jurisdiction in future periods. Due to declines in oil and natural gas prices and the downturn in our industry since late 2008, we anticipate drilling rig utilization and revenue rates will remain at depressed levels for the remainder of 2009. Consequently, we have a valuation allowance of \$4.9 million that fully offsets our foreign deferred tax assets. The foreign net operating loss has an indefinite carryforward period. The foreign net operating loss is primarily due to the special income tax benefits permitted by the Colombian government that allows us to recover 140% of the cost of certain imported assets.

Our accrued insurance premiums and deductibles as of September 30, 2009 include accruals for costs incurred under the self-insurance portion of our health insurance of approximately \$1.4 million and our workers' compensation, general liability and auto liability insurance of approximately \$8.9 million. We have a deductible of \$125,000 per covered individual per year under the health insurance. We have a deductible of \$500,000 per occurrence under our workers' compensation insurance, except in North Dakota, where we do not have a deductible. We have deductibles of \$250,000 and \$100,000 per occurrence under our general liability insurance and auto liability insurance, respectively. We accrue for these costs as claims are incurred based on historical claim development data, and we accrue the costs of administrative services associated with claims processing. We also evaluate our workers' compensation claim cost estimates based on estimates provided by a professional actuary.

#### *Recently Issued Accounting Standards*

*Accounting Standards Codification.* The Financial Accounting Standards Board's (FASB) Accounting Standards Codification (ASC) became effective on July 1, 2009. At that date, the ASC became FASB's officially recognized source of authoritative U.S. generally accepted accounting principles (GAAP) applicable to all public and non-public non-governmental entities, superseding existing FASB Statements of Financial Accounting Standards (SFAS) and other authoritative guidance issued by the American Institute of Certified Public Accountants (AICPA) and Emerging Issues Task Force (EITF). Rules and interpretive releases of the SEC under the authority of federal securities laws are also sources of authoritative GAAP for SEC registrants. All other accounting



literature is considered non-authoritative. The switch to the ASC affects the way companies refer to U.S. GAAP in financial statements and accounting policies. Citing particular content in the ASC involves specifying the unique numeric path to the content through the Topic, Subtopic, Section and Paragraph structure.

*Noncontrolling Interests in Consolidated Financial Statements.* In December 2007, the FASB issued new authoritative accounting guidance under FASB ASC Topic 810 (former SFAS No. 160) which establishes accounting and reporting standards for the non-controlling interest in a subsidiary and for the deconsolidation of a subsidiary. ASC Topic 810 clarifies that a non-controlling interest in a subsidiary, which is sometimes referred to as minority interest, is an ownership interest in the consolidated entity that should be reported as a component of equity in the consolidated financial statements. Among other requirements, ASC 810 requires consolidated net income to be reported at amounts that include the amounts attributable to both the parent and the non-controlling interest. It also requires disclosure, on the face of the consolidated income statement, of the amounts of consolidated net income attributable to the parent and to the non-controlling interest. ASC Topic 810 is effective for fiscal years beginning on or after December 15, 2008. The adoption of ASC topic 810 on January 1, 2009 did not have a material impact on our financial position or results of operations and financial condition.

*Business Combinations.* On January 1, 2009, new authoritative accounting guidance became effective under ASC Topic 805 (formerly SFAS No. 141R) which applies to all transactions and other events in which one entity obtains control over one or more other businesses. ASC Topic 805 requires an acquirer, upon initially obtaining control of another entity, to recognize the assets, liabilities and any non-controlling interest in the acquiree at fair value as of the acquisition date. Contingent consideration is required to be recognized and measured at fair value on the date of acquisition rather than at a later date when the amount of that consideration may be determinable beyond a reasonable doubt. This fair value approach replaces the cost-allocation process required under the previous authoritative accounting guidance (formerly SFAS No. 141) whereby the cost of an acquisition was allocated to the individual assets acquired and liabilities assumed based on their estimated fair value. ASC Topic 805 requires acquirers to expense acquisition-related costs as incurred rather than allocating such costs to the assets acquired and liabilities assumed, as was previously the case under SFAS No. 141. Under ASC Topic 805, the requirements of ASC Topic 420 (formerly SFAS No. 146) relating to the accounting for costs associated with exit or disposal activities, would have to be met in order to accrue for a restructuring plan in purchase accounting. Pre-acquisition contingencies are to be recognized at fair value, unless it is a non-contractual contingency that is not likely to materialize, in which case, nothing should be recognized in purchase accounting and, instead, that contingency would be subject to the probable and estimable recognition criteria of ASC Topic 450 which provides accounting guidance for contingencies. ASC Topic 805 had no impact on our financial position or results of operations and financial condition, since we have not had any business combinations closing on or after the January 1, 2009 effective date.

*Disclosures about Derivative Instruments and Hedging Activities.* On January 1, 2009, new authoritative accounting guidance became effective under ASC Topic 815 (formerly SFAS No. 161) which changes the disclosure requirements for derivative instruments and hedging activities. Entities are required to provide enhanced disclosures about (a) how and why an entity uses derivative instruments, (b) how derivative instruments and related hedged items are accounted for under ASC Topic 815, and (c) how derivative instruments and related hedged items affect an entity's financial position, financial performance, and cash flows. The guidance in ASC Topic 815 is effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008, with early application encouraged. This authoritative accounting guidance encourages, but does not require, comparative disclosures for earlier periods at initial adoption. We do not have any derivative instruments and the January 1, 2009 adoption of this new accounting guidance under ASC Topic 815 had no impact on our financial statement disclosures.

*Fair Value Measurements and Disclosures.* Effective for accounting periods ending after June 15, 2009, new authoritative accounting guidance under ASC Topic 820 (formerly FASB Staff Position FAS 157-4) provides additional guidance for estimating fair value when the volume and level of activity for the asset or liability have significantly decreased and provides additional guidance on disclosure requirements. ASC Topic 820 also includes guidance on identifying circumstances that indicate a transaction is not orderly. The adoption of the new authoritative accounting guidance under ASC Topic 820 during our quarter ending June 30, 2009 did not have a material impact on our financial position or results of operations and financial condition.

*Other-than-temporary Impairments.* Effective for accounting periods ending after June 15, 2009, new authoritative accounting guidance under ASC Topic 320 (formerly FASB Staff Position FAS 115-2 and 124-2) modifies the indicator of other-than-temporary impairment for debt securities. Additionally, ASC Topic 320 changes the amount of an other-than-temporary impairment that is recognized in earnings when there are credit losses on a debt security that management does not intend to sell and it is more-likely-than-not that the entity will not have to sell prior to recovery of the noncredit impairment. In those situations, the portion of the total impairment that is attributable to the credit loss would be recognized in earnings, and the remaining difference between the debt security's amortized cost basis and its fair value would be included in other comprehensive income. The adoption of this new authoritative accounting guidance under ASC Topic 320 during our quarter ending June 30, 2009 did not have a material impact on our financial position or results of operations and financial condition.

*Interim Disclosures about Fair Value of Financial Instruments.* Effective for accounting periods ending after June 15, 2009, new authoritative accounting guidance under ASC Topic 825 (formerly FASB Staff Position FAS 107-1 and APB 28-1) requires disclosures about fair value of financial instruments in quarterly reports as well as in annual reports and applies to certain

investments and long-term debt. The adoption of this new authoritative accounting guidance under ASC Topic 825 during our quarter ending June 30, 2009 did not have a material impact on our financial position or results of operations and financial condition.

*Subsequent Events.* For accounting periods ending after June 15, 2009, new authoritative accounting guidance became effective under ASC Topic 855 (formerly SFAS No. 165) which modifies the definition of what qualifies as a subsequent event—those events or transactions that occur following the balance sheet date, but before the financial statements are issued, or are available to be issued—and requires companies to disclose the date through which it has evaluated subsequent events and the basis for determining that date. The adoption of ASC Topic 855 during the quarter ended June 30, 2009 did not have a material impact on our financial position or results of operations and financial condition.

*Multiple Deliverable Revenue Arrangements.* In October 2009, the FASB issued Accounting Standards Update, 2009-13, Revenue Recognition (Topic 605) *Multiple Deliverable Revenue Arrangements – A Consensus of the FASB Emerging Issues Task Force*. This update provides application guidance on whether multiple deliverables exist, how the deliverables should be separated and how the consideration should be allocated to one or more units of accounting. This update establishes a selling price hierarchy for determining the selling price of a deliverable. The selling price used for each deliverable will be based on vendor-specific objective evidence, if available, third-party evidence if vendor-specific objective evidence is not available, or estimated selling price if neither vendor-specific or third-party evidence is available. We will be required to apply this guidance prospectively for revenue arrangements entered into or materially modified after January 1, 2011; however, earlier application is permitted. We do not expect the adoption of this new guidance to have a material impact on our financial position or results of operations.

### ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

#### *Interest Rate Risk*

We are subject to interest rate market risk on our variable rate debt. As of September 30, 2009, we had \$257.5 million outstanding under our senior secured revolving credit facility subject to variable interest rate risk. The impact of a 1% increase in interest rates on this amount of debt would result in increased interest expense of approximately \$0.6 million and a decrease in net income of approximately \$0.4 million during a quarterly period.

At September 30, 2009, we held \$15.9 million (par value) of investments comprised of tax exempt, auction rate preferred securities (“ARPSs”), which are variable-rate preferred securities and have a long-term maturity with the interest rate being reset through “Dutch auctions” that are held every 7 days. The ARPSs have historically traded at par because of the frequent interest rate resets and because they are callable at par at the option of the issuer. Interest is paid at the end of each auction period. Our ARPSs are AAA/Aaa rated securities, collateralized by municipal bonds and backed by assets that are equal to or greater than 200% of the liquidation preference. Until February 2008, the auction rate securities market was highly liquid. Beginning mid-February 2008, we experienced several “failed” auctions, meaning that there was not enough demand to sell all of the securities that holders desired to sell at auction. The immediate effect of a failed auction is that such holders cannot sell the securities at auction and the interest rate on the security resets to a maximum auction rate. We have continued to receive interest payments on our ARPSs in accordance with their terms. Unless a future auction is successful or the issuer calls the security pursuant to redemption prior to maturity, we may not be able to access the funds we invested in our ARPSs without a loss of principal. We have no reason to believe that any of the underlying municipal securities that collateralize our ARPSs are presently at risk of default. We believe we will ultimately recover the par value of the ARPS without a loss, primarily due to the collateral securing the ARPSs and our estimate of the discounted cash flows that we expect to collect. We do not currently intend to sell our ARPSs at a loss. Also, we believe it is more-likely-than-not that we will not have to sell our ARPS prior to recovery, since our liquidity needs are expected to be met with cash flows from operating activities and our senior secured revolving credit facility. Our ARPSs are designated as available-for-sale and are reported at fair market value with the related unrealized gains or losses, included in accumulated other comprehensive income (loss), net of tax, a component of shareholders’ equity. The estimated fair value of our ARPSs at September 30, 2009 was \$12.7 million compared with a par value of \$15.9 million. The \$3.2 million difference represents a fair value discount due to the current lack of liquidity which is considered temporary and has been recorded as an unrealized loss, net of tax, in accumulated other comprehensive income (loss). There was no portion of the fair value discount attributable to credit losses. We would recognize an impairment charge in our statement of operations if the fair value of our investments falls below the cost basis and is judged to be other-than-temporary or is judged to be attributable to credit losses. Our ARPSs are classified with other long-term assets on our condensed consolidated balance sheet as of September 30, 2009 because of our inability to determine the recovery period of our investments.

#### *Foreign Currency Risk*

While the U.S. dollar is the functional currency for reporting purposes for our Colombian operations, we enter into transactions denominated in Colombian pesos. Nonmonetary assets and liabilities are translated at historical rates and monetary assets and liabilities are translated at exchange rates in effect at the end of the period. Income statement accounts are translated at average rates for the period. As a result, Colombian Peso denominated transactions are affected by changes in exchange rates. We generally accept the exposure to exchange rate movements without using derivative financial instruments to manage this risk. Therefore, both positive and negative movements in the Colombian Peso currency exchange rate against the U.S. dollar has and will continue to affect the reported amount of revenues, expenses, profit, and assets and liabilities in the Company’s consolidated financial statements.

#### ITEM 4. CONTROLS AND PROCEDURES

In accordance with Exchange Act Rules 13a-15 and 15d-15, we carried out an evaluation, under the supervision and with the participation of management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of our disclosure controls and procedures as of the end of the period covered by this Quarterly Report on Form 10-Q. Based on that evaluation, our Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures were effective as of September 30, 2009 to provide reasonable assurance that information required to be disclosed in our reports filed or submitted under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission's rules and forms and that such information is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure.

There has been no change in our internal control over financial reporting that occurred during the three months ended September 30, 2009 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

#### PART II. OTHER INFORMATION

##### ITEM 1. Legal Proceedings

We are involved in litigation arising in the ordinary course of our business. Although the amount of any liability that could arise with respect to these actions cannot be accurately predicted, in management's opinion, any such liability will not have a material adverse effect on our business, financial condition or operating results.

##### ITEM 1A. Risk Factors

Not applicable.

##### ITEM 2. Unregistered Sales of Equity Securities and Use of Proceeds

We did not make any unregistered sales of equity securities during the quarter ended September 30, 2009.

<u>Period</u>	<u>Total Number of Shares Purchased (1)</u>	<u>Average Price Paid per Share (2)</u>	<u>Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs</u>	<u>Maximum Number of Shares that May Yet Be Purchased Under the Plans or Programs</u>
July 1 - July 31	—	\$ —	—	—
August 1 - August 31	5,174	\$ 5.96	—	—
September 1 - September 30	—	\$ —	—	—
Total	5,174	\$ 5.96	—	—

- (1) The shares indicated consist of shares of our common stock tendered by employees to the Company during the three months ended September 30, 2009, to satisfy the employees' tax withholding obligations in connection with the vesting and release of restricted shares, which we repurchased based on the fair market value on the date the relevant transaction occurs.
- (2) The calculation of the average price paid per share does not give effect to any fees, commissions or other costs associated with the repurchase of such shares

ITEM 3. Defaults Upon Senior Securities

Not applicable.

ITEM 4. Submission of Matters to a Vote of Security Holders

Not applicable.

ITEM 5. Other Information

Not applicable.

ITEM 6. EXHIBITS

The following exhibits are filed as part of this report or incorporated by reference herein:

- 2.1 \* - Securities Purchase Agreement, dated January 31, 2008, by and among Pioneer Drilling Company, WEDGE Group Incorporated, WEDGE Energy Holdings, L.L.C., WEDGE Oil & Gas Services, L.L.C., Timothy Daley, John Patterson and Patrick Grissom (Form 8-K dated February 1, 2008 (File No. 1-8182, Exhibit 2.1))
- 2.2 \* - Letter Agreement, dated February 29, 2008, amending the Securities Purchase Agreement, dated January 31, 2008, by and among Pioneer Drilling Company, WEDGE Group Incorporated, WEDGE Energy Holdings, L.L.C., WEDGE Oil & Gas Services, L.L.C., Timothy Daley, John Patterson and Patrick Grissom (Form 8-K dated March 3, 2008 (File No. 1-8182, Exhibit 2.1))
- 3.1 \* - Restated Articles of Incorporation of Pioneer Drilling Company (Form 10-K for the year ended December 31, 2008 (File No. 1-8182, Exhibit 3.1)).
- 3.2 \* - Amended and Restated Bylaws of Pioneer Drilling Company (Form 8-K dated December 15, 2008 (File No. 1-8182, Exhibit 3.1)).
- 4.1 \* - Form of Certificate representing Common Stock of Pioneer Drilling Company (Form S-8 filed November 18, 2003 (Reg. No. 333-110569, Exhibit 4.3)).
- 10.1 \* - First Amendment to Credit Agreement, dated as of October 5, 2009, among Pioneer Drilling Company, the lenders party thereto, and Wells Fargo Bank, N.A., as administrative agent, issuing lender and swing line lender (Form 8-K dated October 5, 2009 (File No. 1-8182, Exhibit 10.1))
- 31.1 \*\* - Certification by Wm. Stacy Locke, President and Chief Executive Officer, pursuant to Rule 13a-14 (a) or Rule 15d-14(a) under the Securities Exchange Act of 1934.
- 31.2 \*\* - Certification by Lorne E. Phillips, Executive Vice President and Chief Financial Officer, pursuant to Rule 13a-14(a) or Rule 15d-14(a) under the Securities Exchange Act of 1934.
- 32.1 # - Certification by Wm. Stacy Locke, President and Chief Executive Officer, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (Subsections (a) and (b) of Section 1350, Chapter 63 of Title 18, United States Code).
- 32.2 # - Certification by Lorne E. Phillips, Executive Vice President and Chief Financial Officer, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (Subsections (a) and (b) of Section 1350, Chapter 63 of Title 18, United States Code).

\* Incorporated herein by reference to the specified prior filing by Pioneer Drilling Company.

\*\* Filed herewith

# Furnished herewith

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

PIONEER DRILLING COMPANY

/s/ Lorne E. Phillips

Lorne E. Phillips

Executive Vice President and Chief Financial Officer  
(Principal Financial Officer and Duly Authorized  
Representative)

Dated: November 5, 2009

## Index to Exhibits

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\* Incorporated herein by reference to the specified prior filing by Pioneer Drilling Company.

\*\* Filed herewith

# Furnished herewith

I, Wm. Stacy Locke, certify that:

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

November 5, 2009

/s/ Wm. Stacy Locke  
Wm. Stacy Locke  
President and Chief Executive Officer

I, Lorne E. Phillips, certify that:

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

November 5, 2009

/s/ Lorne E. Phillips  
Lorne E. Phillips  
Executive Vice President and Chief Financial Officer

Officer's Certification Pursuant to  
Section 906 of the Sarbanes-Oxley Act of 2002  
(18 U.S.C 1350)

In connection with the Quarterly Report on Form 10-Q of Pioneer Drilling Company, a Texas corporation, (the "Company") for the quarter ended September 30, 2009 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), the undersigned, Wm. Stacy Locke, President and Chief Executive Officer, hereby certifies, pursuant to 18 U.S.C. Section 1350, that, to the best of his knowledge:

- (1) The Report is in full compliance with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and
- (2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Dated: November 5, 2009

/s/ Wm. Stacy Locke

Wm. Stacy Locke  
President and Chief Executive Officer

Officer's Certification Pursuant to  
Section 906 of the Sarbanes-Oxley Act of 2002  
(18 U.S.C 1350)

In connection with the Quarterly Report on Form 10-Q of Pioneer Drilling Company, a Texas corporation, (the "Company") for the quarter ended September 30, 2009 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), the undersigned, Lorne E. Phillips, Executive Vice President and Chief Financial Officer, hereby certifies, pursuant to 18 U.S.C. Section 1350, that, to the best of his knowledge:

- (1) The Report is in full compliance with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and
- (2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Dated: November 5, 2009

/s/ Lorne E. Phillips

Lorne E. Phillips  
Executive Vice President and Chief Financial Officer