PIONEER DRILLING CO
Form 10-Q
May 05, 2011

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

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

For the quarterly period ended March 31, 2011

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

PIONEER DRILLING COMPANY

(Exact name of registrant as specified in its charter)

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)

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 þ 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	þ
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 þ

As of April 22, 2011 there were 54,357,345 shares of common stock, par value $0.10 per share, of the registrant issued and outstanding.

PART I. FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

PIONEER DRILLING COMPANY AND SUBSIDIARIES

CONDENSED CONSOLIDATED BALANCE SHEETS

	March 31, 2011 (Unaudited)	December 31, 2010 (Audited)
	(In thousands)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 15,311	$ 22,011
Short-term investments		12,569
Receivables:		
Trade, net of allowance for doubtful accounts	80,896	61,345
Unbilled receivables	20,785	21,423
Insurance recoveries	4,711	4,035
Income taxes	3,186	2,712
Deferred income taxes	10,359	9,867
Inventory	9,628	9,023
Prepaid expenses and other current assets	9,605	8,797
Total current assets	154,481	151,782
Property and equipment, at cost	1,129,864	1,097,179
Less accumulated depreciation	471,484	441,671
Net property and equipment	658,380	655,508
Intangible assets, net of amortization	21,824	21,966
Noncurrent deferred income taxes	2,477	
Other long-term assets	10,825	12,087
Total assets	$ 847,987	$ 841,343
LIABILITIES AND SHAREHOLDERS EQUITY		
Current liabilities:		
Accounts payable	$ 32,039	$ 26,929
Current portion of long-term debt	1,279	1,408
Prepaid drilling contracts	3,719	3,669
Accrued expenses:		
Payroll and related employee costs	17,146	18,057
Insurance premiums and deductibles	9,317	8,774
Insurance claims and settlements	4,711	4,035
Interest	1,138	7,307
Other	8,009	5,461
Total current liabilities	77,358	75,640
Long-term debt, less current portion	283,363	279,530
Other long-term liabilities	14,158	9,680
Noncurrent deferred income taxes	80,288	80,160

Total liabilities	455,167	445,010
Commitments and contingencies (Note 8)		
Shareholders equity:		
Preferred stock, 10,000,000 shares authorized; none issued and outstanding		
Common stock $.10 par value; 100,000,000 shares authorized; 54,357,345 shares and 54,228,170 shares issued and outstanding at March 31, 2011 and December 31, 2010, respectively	5,440	5,425
Additional paid-in capital	341,822	339,105
Treasury stock, at cost; 44,761 and 25,380 shares at March 31, 2011 and December 31, 2010, respectively	(371)	(161)
Accumulated earnings	45,929	51,964
Total shareholders equity	392,820	396,333
Total liabilities and shareholders equity	$ 847,987	$ 841,343

See accompanying notes to condensed consolidated financial statements.

PIONEER DRILLING COMPANY AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS

(Unaudited)

	Three Months Ended March 31, 2011	2010
	(In thousands, except per share data)	
Revenues:		
Drilling services	$ 99,756	$ 55,817
Production services	53,593	30,204
Total revenues	153,349	86,021
Costs and expenses:		
Drilling services	67,509	45,903
Production services	33,228	19,965
Depreciation and amortization	32,256	28,871
General and administrative	14,521	11,473
Bad debt recovery	(84)	(75)
Total costs and expenses	147,430	106,137
Income (loss) from operations	5,919	(20,116)
Other income (expense):		
Interest expense	(7,549)	(4,094)
Interest income	10	20
Other	(6,517)	484
Total other expense	(14,056)	(3,590)
Loss before income taxes	(8,137)	(23,706)
Income tax benefit	2,102	9,159
Net loss	$ (6,035)	$ (14,547)
Loss per common share Basic	$ (0.11)	$ (0.27)
Loss per common share Diluted	$ (0.11)	$ (0.27)
Weighted-average number of shares outstanding Basic	53,968	53,717
Weighted-average number of shares outstanding Diluted	53,968	53,717

See accompanying notes to condensed consolidated financial statements.

PIONEER DRILLING COMPANY AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

(Unaudited)

	Three Months Ended March 31, 2011	2010
	(In thousands)	
Cash flows from operating activities:		
Net loss	$ (6,035)	$ (14,547)
Adjustments to reconcile net loss to net cash provided by (used in) operating activities:		
Depreciation and amortization	32,256	28,871
Allowance for doubtful accounts	(84)	(75)
(Gain) loss on dispositions of property and equipment	923	(772)
Stock-based compensation expense	1,712	1,760
Amortization of debt issuance costs and discount	742	417
Deferred income taxes	(2,823)	(2,307)
Change in other long-term assets	734	(1,722)
Change in other long-term liabilities	4,477	2,864
Changes in current assets and liabilities:		
Receivables	(19,303)	(33,016)
Inventory	(605)	(1,127)
Prepaid expenses and other current assets	(808)	(1,491)
Accounts payable	1,797	8,651
Prepaid drilling contracts	50	1,634
Accrued expenses	(3,989)	6,705
Net cash provided by (used in) operating activities	9,044	(4,155)
Cash flows from investing activities:		
Acquisition of production services businesses	(2,000)	
Purchases of property and equipment	(31,379)	(25,017)
Proceeds from sale of property and equipment	786	949
Proceeds from sale of auction rate securities	12,569	
Net cash used in investing activities	(20,024)	(24,068)
Cash flows from financing activities:		
Debt repayments	(13,529)	(235,738)
Proceeds from issuance of debt	17,000	239,375
Debt issuance costs		(4,737)
Proceeds from exercise of options	560	9
Purchase of treasury stock	(210)	(86)
Excess tax benefit of stock option exercises	459	
Net cash provided by (used in) financing activities	4,280	(1,177)
Net decrease in cash and cash equivalents	(6,700)	(29,400)
Beginning cash and cash equivalents	22,011	40,379
Ending cash and cash equivalents	$ 15,311	$ 10,979
Supplementary disclosure:		
Interest paid	$ 13,004	$ 2,348

Income taxes paid (refunded)	$ 226	$ (187)

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:

Drilling Division Locations	Rig Count
South Texas	18
East Texas	13
West Texas	4
North Dakota	9
North Texas	3
Utah	3
Oklahoma	6
Appalachia	7
Colombia	8

As of April 22, 2011, 50 drilling rigs are operating under drilling contracts. We have 15 drilling rigs that are idle and six drilling rigs have been placed in storage or cold stacked in our Oklahoma drilling division location due to low demand for drilling rigs in that region. We are actively marketing all our idle drilling rigs. We currently have a term contract for one new-build AC drilling rig that is fit for purpose for domestic shale plays that we expect to begin operating in the first quarter of 2012. In early 2011, we established our West Texas drilling division location with three drilling rigs that were previously included in our East Texas drilling division location, and now have a fourth drilling rig operating in this location that was previously included in our South Texas drilling division location. Another nine drilling rigs have been contracted to begin operating in our West Texas drilling division location and will be moved to West Texas from other drilling division locations steadily through the rest of 2011. Currently, seven of our eight drilling rigs located in Colombia are under term contracts with the remaining drilling rig temporarily idle and expected to begin operating again by the end of May 2011.

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.

Our Production Services Division provides a range of services to exploration and production companies, including well services, wireline services, and fishing and rental services. Our production services operations are managed through locations concentrated in the major United States onshore oil and gas producing regions in the Gulf Coast, Mid-Continent, Rocky Mountain and Appalachian states. As of April 22, 2011, we have a premium fleet of 75 well service rigs consisting of seventy 550 horsepower rigs, four 600 horsepower rigs and one 400 horsepower rig. All our well service rigs are currently operating or are being actively marketed, with April 2011 utilization of approximately 88%. We currently provide wireline services with a fleet of 98 wireline units and rental services with approximately $13.7 million of fishing and rental tools. We plan to add another five well service rigs to begin operating by the third quarter of 2011 and three wireline units during the second half of 2011.

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 (GAAP) 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

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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, our estimate of compensation related accruals and our determination of depreciation and amortization expense. The condensed consolidated balance sheet as of December 31, 2010 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, 2010.

In preparing the accompanying unaudited condensed consolidated financial statements, we have reviewed events that have occurred after March 31, 2011, through the filing of this Form 10-Q, for inclusion as necessary.

Recently Issued Accounting Standards

Multiple Deliverable Revenue Arrangements. In October 2009, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) No. 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 are required to apply this guidance prospectively for revenue arrangements entered into or materially modified after January 1, 2011. The adoption of this new guidance has not had a material impact on our financial position or results of operations.

Business Combinations. In December 2010, the FASB issued ASU No. 2010-29, Business Combinations (Topic 805): *Disclosure of Supplementary Pro Forma Information for Business Combinations A consensus of the FASB Emerging Issues Task Force*. This update provides clarification requiring public companies that have completed material acquisitions to disclose the revenue and earnings of the combined business as if the acquisition took place at the beginning of the comparable prior annual reporting period, and also expands the supplemental pro forma disclosures to include a description of the nature and amount of material, nonrecurring pro forma adjustments directly attributable to the business combination included in the reported pro forma revenue and earnings. We are required to apply this guidance prospectively for business combinations for which the acquisition date is on or after January 1, 2011. The adoption of this new guidance has not had 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. Currently, we have 32 contracts with terms of six months to three years in duration. Of these 32 contracts, if not renewed at the end of their terms, 18 will expire by October 22, 2011, seven will expire by April 22, 2012, one will expire by October 22, 2012 and six have a remaining term in excess of 18 months. We have an additional nine drilling rigs under term contracts that we expect will begin operating as they are moved to West Texas steadily through the rest of 2011 and we have a term contract for one new-build AC drilling rig that we expect to begin operating in the first quarter of 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 March 31, 2011, we had restricted cash in the amount of $1.3 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 two years from the escrow account. Restricted cash of $0.7 million and $0.7 million is recorded in other current assets and other long-term assets, respectively. The associated obligation of $0.7 million and $0.7 million is recorded in accrued expenses and other long-term liabilities, respectively.

Investments

As of December 31, 2010, short-term investments represented tax exempt, auction rate preferred securities (ARPS) that were classified as available for sale and reported at fair value. At December 31, 2010, we held $15.9 million (par value) of ARPSs, which were variable-rate preferred securities and had a long-term maturity with the interest rate being reset through Dutch auctions that were held every seven days. On January 19, 2011, we entered into an agreement with a financial institution to sell the ARPSs for $12.6 million, which represented 79% of the par value, plus accrued interest. The $3.3 million difference between the ARPSs par value of $15.9 million and the sales price of $12.6 million represented an other-than-temporary impairment of the ARPSs investment which was reflected as an impairment of investments in our consolidated statement of operations for the year ended December 31, 2010.

Under the ARPSs sales agreement, we retained the unilateral right for a period ending January 7, 2013 to: (a) repurchase all the ARPSs that were sold at the $12.6 million price at which they were initially sold to the financial institution; and (b) if not repurchased, receive additional proceeds from the financial institution upon redemption of the ARPSs by the original issuer of these securities (collectively, the ARPSs Call Option). Upon origination, the fair value of the ARPSs Call Option was estimated to be $0.6 million and was recognized as other income in our condensed consolidated statement of operations for the three months ended March 31, 2011. In accordance with the FASB Accounting Standards Codification (ASC) Topic 820, *Fair Value Measurements and Disclosures*, we are required to assess the value of the ARPSs Call Option at the end of each reporting period, with any changes in fair value recorded within our consolidated statement of operations. As of March 31, 2011, the ARPSs Call Option had an estimated fair value of $0.5 million, and was included in our other long-term assets in our condensed consolidated balance sheet.

Comprehensive Income (Loss)

Comprehensive income (loss) is comprised of net loss and other comprehensive loss. During the three months ended March 31, 2010, the difference between the par value and fair value of the ARPSs was considered temporary and was recorded as unrealized losses, net of taxes, in accumulated other comprehensive income (loss). At December 31, 2010, the difference between par value and fair value was determined to be an other-than-temporary impairment and was reflected as an impairment of investments in our consolidated statement of operations for the year ended December 31, 2010. The following table sets forth the components of comprehensive loss (amounts in thousands):

	Three Months Ended March 31,	
	2011	**2010**
Net loss	$ (6,035)	$ (14,547)
Other comprehensive loss: unrealized losses on securities		(196)
Comprehensive loss	$ (6,035)	$ (14,743)

Income Taxes

Pursuant to ASC Topic 740, *Income Taxes*, 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.

Stock-based Compensation

We recognize compensation cost for stock option, restricted stock and restricted stock unit awards based on the fair value estimated in accordance with ASC Topic 718, *Compensation Stock Compensation*. For our awards with graded vesting, we recognize compensation expense on a straight-line basis over the service period for each separately vesting portion of the award as if the award was, in substance, multiple awards.

We receive a tax deduction for certain stock option exercises during the period the options are exercised, generally for the excess of the market price of our common stock on the exercise date over the exercise price of the stock 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.

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Reclassifications

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

2. Acquisitions

During the three months ended March 31, 2011, we acquired two production services businesses for a total of $2.0 million in cash. The identifiable assets recorded in connection with these acquisitions include fixed assets of $1.0 million, including four wireline units, and intangible assets of $1.0 million representing customer relationships and two non-competition agreements. We did not recognize any goodwill in conjunction with the acquisitions and no contingent assets or liabilities were assumed. Our acquisitions have been accounted for as acquisitions of a business in accordance with ASC Topic 805, *Business Combinations*.

3. Long-term Debt

Long-term debt as of March 31, 2011 and December 31, 2010 consists of the following (amounts in thousands):

	March 31, 2011	**December 31, 2010**
Senior secured revolving credit facility	$ 42,000	$ 37,750
Senior notes	240,313	240,080
Subordinated notes payable	2,317	3,045
Other	12	63
	284,642	280,938
Less current portion	(1,279)	(1,408)
	$ 283,363	$ 279,530

Senior Secured Revolving Credit Facility

We have a credit agreement, as amended, with Wells Fargo Bank, N.A. and a syndicate of lenders which 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 $225 million, all of which matures on August 31, 2012 (the Revolving Credit Facility). The Revolving Credit Facility contains customary mandatory prepayments in respect of asset dispositions, debt incurrence and equity issuances, which are applied to reduce outstanding revolving and swing-line loans and letter of credit exposure, but in no event will reduce the borrowing availability under the Revolving Credit Facility to less than $225 million.

Borrowings under the Revolving Credit Facility bear interest, at our option, at the LIBOR rate or at the bank prime rate, plus an applicable per annum margin that ranges from 3.50% to 6.00% and 2.50% to 5.00%, respectively. The LIBOR margin and bank prime rate margin in effect at April 22, 2011 are 4.0% and 3.0%, respectively. The Revolving Credit Facility requires a commitment fee due quarterly based on the average daily unused amount of the commitments of the lenders, a fronting fee due for each letter of credit issued, and a quarterly letter of credit fee due based on the average undrawn amount of letters of credit outstanding during such period.

Our obligations under the Revolving Credit Facility 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 Revolving Credit Facility are available for acquisitions, working capital and other general corporate purposes.

At April 22, 2011, we had $42.0 million outstanding under our Revolving Credit Facility and $9.2 million in committed letters of credit, which results in borrowing availability of $173.8 million under our Revolving Credit Facility. We may choose to make principal payments to reduce the outstanding debt balance prior to maturity on August 31, 2012 when cash and working capital is sufficient. There are no limitations on our ability to access this borrowing capacity other than maintaining compliance with the covenants under the Revolving Credit Facility. At March 31, 2011, we were in compliance with our financial covenants. Our total consolidated leverage ratio was 2.2 to 1.0, our senior consolidated leverage ratio was 0.4 to 1.0, and our interest coverage ratio was 4.5 to 1.0. The financial covenants contained in our Revolving

Credit Facility include the following:

A maximum total consolidated leverage ratio that cannot exceed:

5.00 to 1.00 as of the end of any fiscal quarter ending March 31, 2011 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 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:

2.00 to 1.00 as of the end of any fiscal quarter ending March 31, 2011 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, our minimum asset coverage ratio 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 Revolving Credit Facility). 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 Revolving Credit Facility 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 Revolving Credit Facility restricts capital expenditures unless (a) after giving effect to such capital expenditure, no event of default would exist under the Revolving Credit Facility and availability under the Revolving Credit Facility 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 $80 million for each fiscal year after 2010. The capital expenditure threshold may be increased by (a) 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 (b) 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 March 31, 2011, our senior consolidated leverage ratio was not greater than 2.50 to 1.00 and therefore, we were not subject to the capital expenditure threshold restrictions listed above.

The Revolving Credit Facility 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 Revolving Credit Facility 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.

Senior Notes

On March 11, 2010, we issued $250 million of unregistered Senior Notes with a coupon interest rate of 9.875% that are due in 2018 (the Senior Notes). The Senior Notes were sold with an original issue discount of $10.6 million that was based on 95.75% of their face value, which will result in an effective yield to maturity of approximately 10.677%. On March 11, 2010, we received $234.8 million of net proceeds from the issuance of the Senior Notes after deductions were made for the $10.6 million of original issue discount and $4.6 million for underwriters fees and other debt offering costs. The net proceeds were used to repay a portion of the borrowings outstanding under our Revolving Credit Facility.

In accordance with a registration rights agreement with the holders of our Senior Notes, we filed an exchange offer registration statement on Form S-4 with the Securities and Exchange Commission that became effective on September 2, 2010. This exchange offer registration statement enabled the holders of our Senior Notes to exchange their Senior Notes for publicly registered notes with substantially identical terms. References to the Senior Notes herein include the Senior Notes issued in the exchange offer.

The Senior Notes are reflected on our condensed consolidated balance sheet at March 31, 2011 with a carrying value of $240.3 million, which represents the $250 million face value net of the $9.7 million unamortized portion of original issue discount. The original issue discount is being amortized over the term of the Senior Notes based on the effective interest method. The Senior Notes will mature on March 15, 2018 with interest due semi-annually in arrears on March 15 and September 15 of each year. We have the option to redeem the Senior Notes, in whole or in part, at any time on or after March 15, 2014 in each case at the redemption price specified in the Indenture dated March 11, 2010 (the Indenture) together with any accrued and unpaid interest to the date of redemption. Prior to March 15, 2014, we may also redeem the Senior Notes, in whole or in part, at a make-whole redemption price specified in the Indenture, together with any accrued and unpaid interest to the date of redemption. In addition, prior to March 15, 2013, we may, on one or more occasions, redeem up to 35% of the aggregate principal amount of the Senior Notes at a redemption price of 109.875% of the principal amount, plus any accrued and unpaid interest to the redemption date, with the net proceeds of certain equity offerings, if at least 65% of the aggregate principal amount of the Senior Notes remains outstanding after such redemption and the redemption occurs within 120 days of the closing of the equity offering.

Upon the occurrence of a change of control, holders of the Senior Notes will have the right to require us to purchase all or a portion of the Senior Notes at a price equal to 101% of the principal amount of each Senior Note, together with any accrued and unpaid interest to the date of purchase. Under certain circumstances in connection with asset dispositions, we will be required to use the excess proceeds of asset dispositions to make an offer to purchase the Senior Notes at a price equal to 100% of the principal amount of each Senior Note, together with any accrued and unpaid interest to the date of purchase.

The Indenture contains certain restrictions on our and certain of our subsidiaries ability to:

- pay dividends on stock;
- repurchase stock or redeem subordinated debt or make other restricted payments;
- incur, assume or guarantee additional indebtedness or issue disqualified stock;
- create liens on our assets;
- enter into sale and leaseback transactions;
- pay dividends, engage in loans, or transfer other assets from certain of our subsidiaries;
- consolidate with or merge with or into, or sell all or substantially all of our properties to another person;
- enter into transactions with affiliates; and
- enter into new lines of business.

These covenants are subject to important exceptions and qualifications. We were in compliance with these covenants as of March 31, 2011. The Senior Notes are not subject to any sinking fund requirements. The Senior Notes are fully and unconditionally guaranteed, jointly and severally, on a senior unsecured basis by certain of our existing domestic subsidiaries and by certain of our future domestic subsidiaries (see Note 9, *Guarantor/Non-Guarantor Condensed Consolidated Financial Statements*).

Subordinated Notes Payable

We have three subordinated notes payable to certain employees that are former shareholders of production services businesses which we have acquired. These subordinated notes payable have interest rates ranging from 6% to 14%, require quarterly or annual payments of principal and interest and have final maturity dates ranging from August 2011 to April 2013.

Debt Issuance Costs

Costs incurred in connection with our Revolving Credit Facility were capitalized and are being amortized using the straight-line method over the term of the Revolving Credit Facility which matures in August 2012. Costs incurred in connection with the issuance of our Senior Notes were capitalized and are being amortized using the straight-line method over the term of the Senior Notes which mature in March 2018. Capitalized debt costs related to the issuance of our long-term debt were approximately $6.2 million and $6.7 million as of March 31, 2011 and December 31, 2010, respectively. We recognized approximately $0.5 million and $0.4 million of associated amortization during the three months ended March 31, 2011 and 2010, respectively.

4. Fair Value of Financial Instruments

ASC Topic 820, *Fair Value Measurements and Disclosures*, defines fair value and provides a hierarchal framework associated with the level of subjectivity used in measuring assets and liabilities at fair value.

At March 31, 2011, our financial instruments consist primarily of cash, trade receivables, trade payables, long-term debt, and our ARPSs Call Option. At December 31, 2010, our financial instruments also included our investments in ARPSs, which were liquidated in January 2011. The carrying value of cash, trade receivables and trade payables are considered to be representative of their respective fair values due to the short-term nature of these instruments.

At December 31, 2010, our ARPSs were reported at amounts that reflected our estimate of fair value. To estimate the fair values of our ARPSs as of December 31, 2010, we used inputs defined by ASC Topic 820 as level 1 inputs which are quoted market prices in active markets for identical securities. We obtained a quoted market price and liquidated the ARPSs on January 19, 2011 based on the terms of the settlement agreement noted above. Therefore, the sales price under the settlement agreement of $12.6 million represented the fair value of the ARPSs at December 31, 2010. The $3.3 million difference between the ARPSs par value of $15.9 million and the sales price of $12.6 million represented an other-than-temporary impairment of the ARPSs investment which was reflected as an impairment of investments in our consolidated statement of operations for the year ended December 31, 2010.

At March 31, 2011, our ARPSs Call Option is reported at an amount that reflects our current estimate of fair value. To estimate the value of our ARPSs Call Option as of March 31, 2011, we used inputs defined by ASC Topic 820 as level 3 inputs, which are significant unobservable inputs. The fair value of the ARPSs Call Option was estimated using a modified Black-Scholes model, based on an analysis of recent historical transactions for securities with similar characteristics to the underlying ARPSs, and an analysis of the probability that the options would be exercisable as a result of the underlying ARPSs being redeemed or traded in a secondary market at an amount greater than the option price before the expiration date. As of March 31, 2011, the ARPSs Call Option had an estimated fair value of $0.5 million, and was included in our other long-term assets in our condensed consolidated balance sheet. Future changes in the fair values of the ARPSs Call Option will be reflected in other income (expense) in our consolidated statements of operations.

The fair value of our long-term debt at March 31, 2011 and December 31, 2010 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. The following table presents the supplemental fair value information about long-term debt at March 31, 2010 and December 31, 2010 (amounts in thousands):

	March 31, 2011		**December 31, 2010**	
	Carrying Amount	**Fair Value**	**Carrying Amount**	**Fair Value**
Total debt	$ 284,642	$ 318,856	$ 280,938	$ 308,630

5. Earnings (Loss) Per Common Share

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

	Three Months Ended March 31,	
	2011	**2010**
Basic		
Net loss	$ (6,035)	$ (14,547)
Weighted-average shares:	53,968	53,717
Loss per share	$ (0.11)	$ (0.27)
Diluted		
Net loss	$ (6,035)	$ (14,547)
Weighted-average shares:		
Outstanding	53,968	53,717
Diluted effect of stock options, restricted stock, and restricted stock unit awards		
	53,968	53,717
Loss per share	$ (0.11)	$ (0.27)

Outstanding stock options, restricted stock and restricted stock unit awards representing a total of 1,253,919 shares and 870,308 shares of common stock were excluded from the diluted loss per share calculations for the three month periods ended March 31, 2011 and 2010, respectively, because the effect of their inclusion would be antidilutive.

6. Equity Transactions and Stock-based Compensation Plans

We grant stock option awards with vesting based on time of service conditions and we grant restricted stock unit awards with vesting based on time of service conditions, and in certain cases, subject to performance and market conditions. We recognize compensation cost for stock option, restricted stock and restricted stock unit awards based on the fair value estimated in accordance with ASC Topic 718, *Compensation Stock Compensation*. For our awards with graded vesting, we recognize compensation expense on a straight-line basis over the service period for each separately vesting portion of the award as if the award was, in substance, multiple awards.

Stock Options

We grant stock option awards which generally become exercisable over a three -year period and expire ten years after the date of grant. Our stock-based compensation plans provide that all stock option awards must have an exercise price not less than the fair market value of our common stock on the date of grant. We issue shares of our common stock when vested stock option awards are exercised.

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 based on a weighted-average calculation for the three months ended March 31, 2011 and 2010:

	Three Months Ended March 31,	
	2011	**2010**
Expected volatility	65%	62%
Risk-free interest rates	1.5%	2.6%
Expected life in years	4.33	5.65
Options granted	597,298	731,200
Grant-date fair value	$4.67	$5.03

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.

The following table summarizes the compensation expense recognized for stock option awards during the three months ended March 31, 2011 and 2010 (amounts in thousands):

	Three Months Ended March 31,	
	2011	**2010**
General and administrative expense	$ 997	$ 1,073
Operating costs	81	143
	$ 1,078	$ 1,216

During the three months ended March 31, 2011 and 2010, respectively, employees exercised stock options for the purchase of 127,300 shares and 2,300 shares of common stock. 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.

Restricted Stock

We grant restricted stock awards that vest over a three-year period with a fair value based on the closing price of our common stock on the date of the grant. When restricted stock awards are granted, shares of our common stock are considered issued, but subject to certain restrictions. We did not grant any restricted stock awards during the three months ended March 31, 2011 or 2010.

The following table summarizes the compensation expense recognized for restricted stock awards during the three months ended March 31, 2011 and 2010 (amounts in thousands):

	Three Months Ended March 31, 2011	Three Months Ended March 31, 2010
General and administrative expense	$ 160	$ 327
Operating costs	24	44
	$ 184	$ 371

Restricted Stock Units

We grant restricted stock unit awards with vesting based on time of service conditions only (time-based RSUs), and we grant restricted stock unit awards with vesting based on time of service, which are also subject to performance and market conditions (performance-based RSUs). Shares of our common stock are issued to recipients of restricted stock units only when they have satisfied the applicable vesting conditions.

Our time-based RSU s generally vest over a three-year period, with fair values based on the closing price of our common stock on the date of grant. The following table summarizes the number of time-based RSUs granted and the weighted-average grant-date fair values of each time-based RSU during the three months ended March 31, 2011 and 2010:

	Three Months Ended March 31, 2011	Three Months Ended March 31, 2010
Time-based RSUs granted	102,903	72,120
Weighted-average grant-date fair value	$ 9.01	$ 8.86

Our performance-based RSUs are granted at a target number of issuable shares, for which the final number of shares of common stock is adjusted based on our actual achievement levels that are measured against predetermined performance conditions. The following table summarizes the number of performance-based RSUs granted and the weighted-average grant-date fair values of each performance-based RSU during the three months ended March 31, 2011 and 2010:

	Three Months Ended March 31, 2011	Three Months Ended March 31, 2010
Performance-based RSUs granted	146,479	194,680
Weighted-average grant-date fair value	$ 9.49	$ 8.86

Performance-based RSUs granted during the three months ended March 31, 2011 will cliff vest after 39 months from the date of grant. The number of shares of common stock awarded will be based upon the Company s achievement in certain performance conditions, as compared to a predefined peer group, over the performance period from January 1, 2011 through December 31, 2013. Approximately one-third of the performance-based RSU s are subject to a market condition, and therefore the fair value of these awards is measured using a Monte Carlo simulation model. Compensation expense for awards with a market condition is reduced only for estimated forfeitures; no adjustment to expense is otherwise made, regardless of the number of shares issued, if any. The remaining two-thirds of the performance-based RSUs are subject to performance conditions, and therefore the fair value is based on the closing price of our common stock on the date of grant, applied to the estimated number of shares that will be awarded. Compensation expense ultimately recognized for awards with performance conditions will be equal to the fair value of the restricted stock unit award based on the actual outcome of the service and performance conditions.

Performance-based RSUs granted during the three months ended March 31, 2010 have a fair value that is based on the closing price of our common stock on the date of grant. Compensation cost ultimately recognized will be equal to the fair value of the restricted stock unit award based on the actual outcome of the service and performance conditions. We determined that 166,918 shares, or 86.7% of the target number of shares net of forfeitures, were earned based on the Company s achievement of certain performance measures, as compared to the predefined peer group, over the performance period from January 1, 2008 through December 31, 2010. These shares remain subject to graded vesting over a three-year period, with the first tranche of shares vesting in April 2011.

The following table summarizes the compensation expense recognized for all time-based and performance-based restricted stock unit awards during the three months ended March 31, 2011 and 2010 (amounts in thousands):

	Three Months Ended March 31,	
	2011	2010
General and administrative expense	$ 389	$ 151
Operating costs	61	22
	$ 450	$ 173

7. Segment Information

At March 31, 2011, 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.

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 locations:

Drilling Division Locations	Rig Count
South Texas	18
East Texas	13
West Texas	4
North Dakota	9
North Texas	3
Utah	3
Oklahoma	6
Appalachia	7
Colombia	8

Production Services Division Our Production Services Division provides a range of services to oil and gas exploration and production companies, including well services, wireline services, and fishing and rental services. Our production services operations are managed through locations 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 75 well service rigs consisting of seventy 550 horsepower rigs, four 600 horsepower rigs and one 400 horsepower rig. We provide wireline services with a fleet of 98 wireline units and rental services with approximately $13.7 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 March 31, 2011 and 2010 (amounts in thousands):

	As of and for the Three Months Ended March 31, 2011			
	Drilling Services Division	Production Services Division	Corporate	Total
Identifiable assets	$ 581,725	$ 241,836	$ 24,426	$ 847,987
Revenues	$ 99,756	$ 53,593	$	$ 153,349
Operating costs	67,509	33,228		100,737
Segment margin	$ 32,247	$ 20,365	$	$ 52,612
Depreciation and amortization	$ 24,486	$ 7,495	$ 275	$ 32,256

Capital expenditures	$ 19,113	$ 15,444	$ 137	$ 34,694

	As of and for the Three Months Ended March 31, 2010			
	Drilling Services Division	Production Services Division	Corporate	Total
Identifiable assets	$ 579,528	$ 236,362	$ 23,455	$ 839,345
Revenues	$ 55,817	$ 30,204	$	$ 86,021
Operating costs	45,903	19,965		65,868
Segment margin	$ 9,914	$ 10,239	$	$ 20,153
Depreciation and amortization	$ 22,292	$ 6,274	$ 305	$ 28,871
Capital expenditures	$ 29,886	$ 6,152	$ 31	$ 36,069

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

	Three Months Ended March 31,	
	2011	2010
Segment margin	$ 52,612	$ 20,153
Depreciation and amortization	(32,256)	(28,871)
General and administrative	(14,521)	(11,473)
Bad debt recovery	84	75
Income (loss) from operations	$ 5,919	$ (20,116)

The following table sets forth certain financial information for our international operations in Colombia as of and for the three months ended March 31, 2011 and 2010 which is included in our Drilling Services Division (amounts in thousands):

	As of and for the Three Months Ended March 31,	
	2011	2010
Identifiable assets	$ 157,285	$ 148,099
Revenues	$ 24,234	$ 15,744

Identifiable assets as of March 31, 2011 include five drilling rigs that are owned by our Colombia subsidiary and three drilling rigs that are owned by one of our domestic subsidiaries and leased to our Colombia subsidiary. Identifiable assets as of March 31, 2010 include five drilling rigs that are owned by our Colombia subsidiary and two drilling rigs that are owned by one of our domestic subsidiaries and leased to our Colombia subsidiary.

8. 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 $52.2 million relating to our performance under these bonds.

The Colombian government enacted a tax reform act which, among other things, adopted a one-time, net-worth tax for all Colombian entities, which was assessed on January 1, 2011 and is payable in eight semi-annual installments from 2011 through 2014. Based on our Colombian operations net equity, measured on a Colombian tax basis as of January 1, 2011, our total net-worth tax obligation is approximately $7.3 million, which is not deductible for tax purposes. We recognized this tax obligation in full during the three months ended March 31, 2011 in other expense in our consolidated statement of operations, and in other accrued expenses and other long-term liabilities on our consolidated balance sheet as of March 31, 2011.

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.

9. Guarantor/Non-Guarantor Condensed Consolidated Financial Statements

Our Senior Notes are fully and unconditionally guaranteed, jointly and severally, on a senior unsecured basis by our existing domestic subsidiaries, except for Pioneer Services Holdings, LLC, and certain of our future domestic subsidiaries. The subsidiaries that generally operate our non-U.S. business concentrated in Colombia do not guarantee our Senior Notes. The non-guarantor subsidiaries do not have any payment obligations under the Senior Notes, the guarantees or the Indenture. In the event of a bankruptcy, liquidation or reorganization of any non-guarantor subsidiary, such non-guarantor subsidiary will pay the holders of its debt and other liabilities, including its trade creditors, before it will be able to distribute any of its assets to us. In the future, any non-U.S. subsidiaries, immaterial subsidiaries and subsidiaries that we designate as unrestricted subsidiaries under the Indenture will not guarantee the Senior Notes. As of March 31, 2011, there were no restrictions on the ability of subsidiary guarantors to transfer funds to the parent company.

As a result of the guarantee arrangements, we are presenting the following condensed consolidated balance sheets, statements of operations and statements of cash flows of the issuer, the guarantor subsidiaries and the non-guarantor subsidiaries.

CONDENSED CONSOLIDATED BALANCE SHEETS

(Unaudited, in thousands)

	March 31, 2011				
	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
ASSETS					
Current assets:					
Cash and cash equivalents	$ 15,379	$ (2,829)	$ 2,761	$	$ 15,311
Receivables		80,427	29,151		109,578
Intercompany receivable (payable)	(119,249)	131,921	(12,672)		
Deferred income taxes	380	5,094	4,885		10,359
Inventory		3,147	6,481		9,628
Prepaid expenses and other current assets	200	4,819	4,586		9,605
Total current assets	(103,290)	222,579	35,192		154,481
Net property and equipment	1,548	566,900	90,682	(750)	658,380
Investment in subsidiaries	754,872	109,441		(864,313)	
Intangible assets, net of amortization	157	21,667			21,824
Noncurrent deferred income taxes	18,715		2,477	(18,715)	2,477
Other long-term assets	6,762	2,176	1,887		10,825
Total assets	$ 678,764	$ 922,763	$ 130,238	$ (883,778)	$ 847,987
LIABILITIES AND SHAREHOLDERS EQUITY					
Current liabilities:					
Accounts payable	$ 447	$ 27,151	$ 4,441		$ 32,039
Current portion of long-term debt	12	1,267			1,279
Prepaid drilling contracts		1,050	2,669		3,719
Accrued expenses	2,102	32,037	6,182		40,321
Total current liabilities	2,561	61,505	13,292		77,358
Long-term debt, less current portion	282,313	1,050			283,363
Other long-term liabilities	320	6,333	7,505		14,158
Deferred income taxes		99,003		(18,715)	80,288
Total liabilities	285,194	167,891	20,797	(18,715)	455,167
Total shareholders equity	393,570	754,872	109,441	(865,063)	392,820

Total liabilities and shareholders equity	$ 678,764	$ 922,763	$ 130,238	$ (883,778)	$ 847,987

CONDENSED CONSOLIDATED BALANCE SHEETS

(Unaudited, in thousands)

	December 31, 2010				
	Parent	**Guarantor Subsidiaries**	**Non-Guarantor Subsidiaries**	**Eliminations**	**Consolidated**
ASSETS					
Current assets:					
Cash and cash equivalents	$ 15,737	$ (1,840)	$ 8,114	$	$ 22,011
Short-term investments	12,569				12,569
Receivables		78,575	10,940		89,515
Intercompany receivable (payable)	(80,900)	80,942	(42)		
Deferred income taxes	178	4,167	5,522		9,867
Inventory		2,874	6,149		9,023
Prepaid expenses and other current assets	263	4,604	3,930		8,797
Total current assets	(52,153)	169,322	34,613		151,782
Net property and equipment	1,601	562,390	92,267	(750)	655,508
Investment in subsidiaries	714,292	114,483		(828,775)	
Intangible assets, net of amortization	235	21,731			21,966
Noncurrent deferred income taxes	14,632			(14,632)	
Other long-term assets	6,739	2,844	2,504		12,087
Total assets	$ 685,346	$ 870,770	$ 129,384	$ (844,157)	$ 841,343
LIABILITIES AND SHAREHOLDERS EQUITY					
Current liabilities:					
Accounts payable	$ 242	$ 20,134	$ 6,553	$	$ 26,929
Current portion of long-term debt	63	1,345			1,408
Prepaid drilling contracts		1,000	2,669		3,669
Accrued expenses	9,861	30,786	2,987		43,634
Total current liabilities	10,166	53,265	12,209		75,640
Long-term debt, less current portion	277,830	1,700			279,530
Other long-term liabilities	267	6,744	2,669		9,680
Deferred income taxes		94,769	23	(14,632)	80,160
Total liabilities	288,263	156,478	14,901	(14,632)	445,010
Total shareholders equity	397,083	714,292	114,483	(829,525)	396,333
Total liabilities and shareholders equity	$ 685,346	$ 870,770	$ 129,384	$ (844,157)	$ 841,343

CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS

(Unaudited, in thousands)

	Three Months Ended March 31, 2011				
	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Revenues:	$	$ 129,115	$ 24,234	$	$ 153,349
Costs and expenses:					
Operating costs		81,878	18,859		100,737
Depreciation and amortization	275	29,118	2,863		32,256
General and administrative	4,131	9,890	608	(108)	14,521
Intercompany leasing		(1,215)	1,215		
Bad debt recovery		(84)			(84)
Total costs and expenses	4,406	119,587	23,545	(108)	147,430
Income (loss) from operations	(4,406)	9,528	689	108	5,919
Other income (expense):					
Equity in earnings of subsidiaries	807	(5,027)		4,220	
Interest expense	(7,472)	(77)			(7,549)
Interest income		4	6		10
Other	532	236	(7,177)	(108)	(6,517)
Total other income (expense)	(6,133)	(4,864)	(7,171)	4,112	(14,056)
Income (loss) before income taxes	(10,539)	4,664	(6,482)	4,220	(8,137)
Income tax benefit (expense)	4,504	(3,857)	1,455		2,102
Net earnings (loss)	$ (6,035)	$ 807	$ (5,027)	$ 4,220	$ (6,035)

	Three Months Ended March 31, 2010				
	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Revenues:	$	$ 70,277	$ 15,744	$	$ 86,021
Costs and expenses:					
Operating costs		52,624	13,244		65,868
Depreciation and amortization	305	26,320	2,246		28,871
General and administrative	4,025	6,877	661	(90)	11,473
Intercompany leasing		(755)	755		
Bad debt recovery		(75)			(75)
Total costs and expenses	4,330	84,991	16,906	(90)	106,137
Income (loss) from operations	(4,330)	(14,714)	(1,162)	90	(20,116)
Other income (expense):					
Equity in earnings of subsidiaries	(6,245)	174		6,071	
Interest expense	(3,972)	(112)	(10)		(4,094)
Interest income		14	6		20
Other		177	397	(90)	484

Total other income (expense)	(10,217)	253	393	5,981	(3,590)
Income (loss) before income taxes	(14,547)	(14,461)	(769)	6,071	(23,706)
Income tax benefit (expense)		8,216	943		9,159
Net earnings (loss)	$ (14,547)	$ (6,245)	$ 174	$ 6,071	$ (14,547)

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

(Unaudited, in thousands)

	Three Months Ended March 31, 2011				
	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Cash flows from operating activities:	$ (17,846)	$ 30,450	$ (3,560)	$	$ 9,044
Cash flows from investing activities:					
Acquisition of other production services businesses		(2,000)			(2,000)
Purchases of property and equipment	(90)	(29,492)	(1,797)		(31,379)
Proceeds from sale of property and equipment		782	4		786
Proceeds from sale of auction rate securities	12,569				12,569
	12,479	(30,710)	(1,793)		(20,024)
Cash flows from financing activities:					
Debt repayments	(12,800)	(729)			(13,529)
Proceeds from issuance of debt	17,000				17,000
Proceeds from exercise of options	560				560
Purchase of treasury stock	(210)				(210)
Excess tax benefit of stock option exercises	459				459
	5,009	(729)			4,280
Net increase (decrease) in cash and cash equivalents	(358)	(989)	(5,353)		(6,700)
Beginning cash and cash equivalents	15,737	(1,840)	8,114		22,011
Ending cash and cash equivalents	$ 15,379	$ (2,829)	$ 2,761	$	$ 15,311

	Three Months Ended March 31, 2010				
	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Cash flows from operating activities:	$ (22,081)	$ 19,434	$ (1,508)	$	$ (4,155)
Cash flows from investing activities:					
Purchases of property and equipment	(31)	(18,988)	(5,998)		(25,017)
Proceeds from sale of property and equipment		949			949
	(31)	(18,039)	(5,998)		(24,068)
Cash flows from financing activities:					
Debt repayments	(234,813)	(925)			(235,738)
Proceeds from issuance of debt	239,375				239,375
Debt issuance costs	(4,737)				(4,737)
Proceeds from exercise of options	9				9
Purchase of treasury stock	(86)				(86)
	(252)	(925)			(1,177)
Net increase (decrease) in cash and cash equivalents	(22,364)	470	(7,506)		(29,400)
Beginning cash and cash equivalents	33,352	(2,716)	9,743		40,379

Ending cash and cash equivalents	$	10,988	$	(2,246)	$	2,237	$		$	10,979

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 and our senior notes, 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, 2010. 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, 2010 could also have a 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 much of the onshore oil and gas producing regions of the United States and internationally in Colombia. Pioneer Drilling Company was incorporated under the laws of the State of Texas in 1979 as the successor to a business that had been operating since 1968. Our business has grown through acquisitions and through organic growth. Since September 1999, 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. We significantly expanded our service offerings in March 2008, 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 senior secured revolving credit facility. Drilling services and production services are fundamental to establishing and maintaining the flow of oil and natural gas throughout the productive life of 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 and Supplementary Data,* 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:

Drilling Division Locations	**Rig Count**
South Texas	18
East Texas	13
West Texas	4
North Dakota	9
North Texas	3
Utah	3
Oklahoma	6
Appalachia	7
Colombia	8

As of April 22, 2011, 50 drilling rigs are operating under drilling contracts. We have 15 drilling rigs that are idle and six drilling rigs have been placed in storage or cold stacked in our Oklahoma drilling division location due to low demand for drilling rigs in that region. We are actively marketing all our idle drilling rigs. We currently have a term contract for one new-build AC drilling rig that is fit for purpose for domestic shale plays that we expect to begin operating in the first quarter of 2012. In early 2011, we established our West Texas drilling division location with three drilling rigs that were previously included in our East Texas drilling division location, and now have a fourth drilling rig operating in this location which we moved from

our South Texas drilling division location. Another nine drilling rigs have been contracted to begin operating in this drilling division location and will be moved to West Texas from other drilling division locations steadily through the rest of 2011. Currently, seven of our eight drilling rigs located in Colombia are under term contracts with the remaining drilling rig temporarily idle and expected to begin operating again by the end of May 2011.

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 range of services to oil and gas exploration and production companies, including well services, wireline services, and fishing and rental services. Our production services operations are managed through locations 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 exploration and production 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 premium well service rig fleet 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 acquired one well service rig in early 2011, resulting in a total of 75 well service rigs in ten locations as of April 22, 2011. Our well service rig fleet consists of seventy 550 horsepower rigs, four 600 horsepower rigs, and one 400 horsepower rig. All our well service rigs are currently operating or are being actively marketed, with April 2011 utilization of approximately 88%. We plan to add another five well service rigs to our fleet to begin operating by the third quarter of 2011.

Wireline Services. In order for oil and gas exploration and production 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 wireline units 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 exploration and production companies to evaluate the integrity of wellbore casing, recover pipe, or install bridge plugs. We have acquired 14 wireline units during 2011, resulting in a total of 98 wireline units in 24 locations as of April 22, 2011. We plan to add another three wireline units during the second half of 2011.

Fishing and Rental Services. During drilling operations, oil and gas exploration and production companies frequently rent unique equipment such as power swivels, foam circulating units, blow-out preventers, air drilling equipment, pumps, tanks, pipe, tubing, and fishing tools. We provide rental services out of four locations in Texas and Oklahoma. As of March 31, 2011 our fishing and rental tools have a gross book value of $13.7 million.

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.pioneerdrlg.com. We make available free of charge though our website our Annual Reports on our 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

Demand for oilfield services offered by our industry is a function of our customers willingness to make operating expenditures 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. From late 2008 and into late 2009, there was substantial volatility and a decline in oil and natural gas prices due to the downturn in

the global economic environment. In response, our customers curtailed their drilling programs and reduced their production activities, particularly in natural gas producing regions, which resulted in a decrease in demand and revenue rates for certain of our drilling rigs and production services equipment. Additionally, there was uncertainty in the capital markets and access to financing was limited. These conditions adversely affected our business environment. With increasing oil and natural gas prices during 2010, exploration and production companies modestly increased their exploration and production spending for 2010 and industry rig utilization and revenue rates improved, particularly in oil-producing regions and in certain shale regions. We expect continued modest increases in exploration and production spending for 2011, which we expect will result in modest increases in industry rig utilization and revenue rates in 2011, as compared to 2010. 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 the Annual Report on Form 10-K for the year ended December 31, 2010.

On April 22, 2011, the spot price for West Texas Intermediate crude oil was $111.71, the spot price for Henry Hub natural gas was $4.33 and the Baker Hughes U.S. land rig count was 1,754, a 24% increase from 1,415 on April 23, 2010. The 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 well service rig count for three months ended March 31, 2011 and each of the last five years ended on March 31 were:

	Three Months Ended March 31,	Years Ended March 31,				
	2011	2011	2010	2009	2008	2007
Oil (West Texas Intermediate)	$ 93.86	$ 83.05	$ 70.42	$ 86.35	$ 82.50	$ 64.96
Natural Gas (Henry Hub)	$ 4.13	$ 4.10	$ 4.01	$ 7.78	$ 7.27	$ 6.53
U.S. Land Rig Count	1,674	1,589	1,034	1,690	1,685	1,589
U.S. Well Service Rig Count	2,013	1,925	1,668	2,392	2,412	2,376

As represented in the table above, increases in oil and natural gas prices from 2004 to late 2008 resulted in corresponding increases in the U.S. land rig counts and U.S. well service rig counts, while declines in prices from late 2008 to late 2009 led to decreases in the U.S. land rig counts and U.S. well service rig counts. Since late 2009, increases in oil and natural gas prices have caused modest increases in exploration and production spending and the corresponding increases in drilling and well services activities is reflected by increases in the U.S. land rig counts and the U.S. well service rig counts in 2010 and 2011.

Our business is influenced substantially by both operating and capital expenditures by exploration and production companies. Exploration and production spending is generally categorized as either a capital expenditure or operating expenditure.

Capital expenditures by oil and gas exploration and production 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 long periods 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.

Because existing oil and natural gas wells require ongoing spending to maintain production, expenditures by exploration and production companies for the maintenance of existing wells are relatively stable and predictable. In contrast, capital expenditures by exploration and production companies for exploration and drilling are more directly influenced by current and expected oil and natural gas prices and generally reflect the volatility of commodity prices.

Strategy

In past years, our strategy was to become a premier land drilling and production services company through steady and disciplined growth. We executed this strategy by acquiring and building a high quality drilling rig fleet and production services business that operate in active drilling markets in the United States and Colombia. Our long-term strategy is to maintain and leverage our position as a leading land drilling and production services company, continue to expand our relationships with existing customers, expand our customer base in the areas in which we currently operate and further enhance our geographic diversification through selective international expansion. The key elements of this long-term strategy include:

Further Strengthen our Competitive Position in the Most Attractive Domestic Markets. Shale plays and non-shale oil or liquid rich environments are increasingly important to domestic hydrocarbon production and not all drilling rigs are capable of successfully drilling in these unconventional opportunities. We currently have 39 drilling rigs capable of operating in unconventional plays. Of these 39 drilling rigs, 30 are currently operating in unconventional plays, eight are currently located in Colombia and one is operating domestically on a conventional well. We have 21 other drilling rigs that would require additional upgrades such as top drives to be capable of operating in unconventional plays. We may consider further upgrades in the future if they will result in profitable contract terms that justify the additional investment. We also intend to continue adding capacity to our wireline and well servicing product offerings, which are well positioned to capitalize on increased shale development.

Increase our Exposure to Oil-Driven Drilling Activity. We have intentionally increased our exposure to oil-related activities by redeploying certain of our assets into predominately oil-producing regions and actively seeking contracts with oil-focused producers. As of April 22, 2011, approximately 65% of both our working drilling rigs and our well service rigs are operating on wells that are targeting or producing oil. In addition, we currently have four rigs drilling in the Permian Basin, an oil producing region, and expect to have another nine drilling rigs operating in this area by the end of 2011. We believe that by targeting a balanced mix of oil and natural gas activities, we can lessen our exposure to fluctuations in capital spending associated with changes in any single commodity price. We believe that our flexible rig fleet and production services assets allow us to target opportunities focused on both natural gas and oil.

Selectively Expand our International Operations. In early 2007, we announced our intention to selectively expand internationally and began a relationship with Ecopetrol S.A. in Colombia after a comprehensive review of international opportunities wherein we determined that Colombia offered an attractive mix of favorable business conditions, political stability, and a long-term commitment to expanding national oil and gas production. We now have eight drilling rigs in Colombia. We are continuously evaluating additional international expansion opportunities and intend to target international markets that share the favorable characteristics of our Colombian operations and which would allow us to deploy sufficient assets in order to realize economies of scale.

Continue Growth with Select Capital Deployment. We intend to invest in the growth of our business by continuing to strategically upgrade our existing assets, selectively engaging in new-build opportunities, and potentially making selective acquisitions. Our capital investment decisions are determined by an analysis of the projected return on capital employed, which is based on the terms of secured contracts whenever possible, and the investment must be consistent with our strategic objectives. We currently have a term contract for one new-build AC drilling rig that is fit for purpose for domestic shale plays that we expect to begin operating in the first quarter of 2012. We have also significantly increased our production services fleets with the addition of 14 wireline units and one well service rig so far in 2011, and expect to add another five well service rigs and three wireline units by the end of 2011.

Liquidity and Capital Resources

Sources of Capital Resources

Our principal liquidity requirements have been for working capital needs, capital expenditures and selective acquisitions. Our principal sources of liquidity consist of: (i) cash and cash equivalents (which equaled $15.3 million as of March 31, 2011); (ii) cash generated from operations; and (iii) the unused portion of our senior secured revolving credit facility (the Revolving Credit Facility). Our Revolving Credit Facility 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 $225 million, all of which matures on August 31, 2012. At April 22, 2011, we had $42.0 million outstanding under our Revolving Credit Facility and $9.2 million in committed letters of credit, which results in borrowing availability of $173.8 million under our Revolving Credit Facility. There are no limitations on our ability to access the full borrowing availability under the Revolving Credit Facility other than maintaining compliance with the covenants in the Revolving Credit Facility. Additional information regarding these covenants is provided in the *Debt Requirements* section below. Borrowings under the Revolving Credit Facility are available for selective acquisitions, working capital and other general corporate purposes. We currently expect that cash and cash equivalents, cash generated from operations and available borrowings under our Revolving Credit Facility are adequate to cover our liquidity requirements for at least the next 12 months.

In July 2009, we filed a registration statement that permits us to sell equity or debt in one or more offerings up to a total dollar amount of $300 million. In November 2009, we obtained $24.0 million in net proceeds when we sold 3,820,000 shares of our common stock at $6.75 per share, less underwriters commissions, pursuant to a public offering under the $300 million shelf registration statement. The remaining availability under the $300 million shelf registration statement for equity or debt is $274.2 million as of April 22, 2011. In the future, we may consider equity or debt offerings, as appropriate, to meet our liquidity needs.

Uses of Capital Resources

For the three months ended March 31, 2011, we had $34.7 million of additions to our property and equipment. Currently, we expect to spend approximately $170 million to $185 million on capital expenditures during 2011. Our planned capital expenditures for the year ending December 31, 2011 include a total of 17 wireline units, six well service rigs, two new-build AC drilling rigs, upgrades to drilling rigs being relocated to our West Texas drilling division location and routine capital expenditures. Actual capital expenditures may vary depending on the level of new-build and other expansion opportunities that meet our strategic and return on capital criteria. We expect to fund these capital expenditures from operating cash flow in excess of our working capital requirements and, as necessary, from borrowings under our Revolving Credit Facility.

Working Capital

Our working capital was $77.1 million at March 31, 2011, compared to $76.1 million at December 31, 2010. Our current ratio, which we calculate by dividing our current assets by our current liabilities, was 2.0 at both March 31, 2011 and December 31, 2010.

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 (in thousands):

	March 31, 2011	December 31, 2010	Change
Cash and cash equivalents	$ 15,311	$ 22,011	$ (6,700)
Short-term investments		12,569	(12,569)
Receivables:			
Trade, net of allowance for doubtful accounts	80,896	61,345	19,551
Unbilled receivables	20,785	21,423	(638)
Insurance recoveries	4,711	4,035	676
Income taxes	3,186	2,712	474
Deferred income taxes	10,359	9,867	492
Inventory	9,628	9,023	605
Prepaid expenses and other current assets	9,605	8,797	808
Current assets	154,481	151,782	2,699
Accounts payable	32,039	26,929	5,110
Current portion of long-term debt	1,279	1,408	(129)
Prepaid drilling contracts	3,719	3,669	50
Accrued expenses:			
Payroll and related employee costs	17,146	18,057	(911)
Insurance premiums and deductibles	9,317	8,774	543
Insurance claims and settlements	4,711	4,035	676
Interest	1,138	7,307	(6,169)
Other	8,009	5,461	2,548
Current liabilities	77,358	75,640	1,718
Working capital	$ 77,123	$ 76,142	$ 981

The decrease in cash and cash equivalents was primarily due to $31.4 million used for purchases of property and equipment and $2.0 million used for the purchases of production services businesses, offset by $12.6 million in proceeds from the sale of the ARPSs, $9.0 million of cash provided by operations and $3.5 million in proceeds from debt borrowings, net of debt repayments, during the three months ended March 31, 2011.

The short-term investments balance at December 31, 2010 represented the fair value of our investment in ARPSs, which were liquidated in January 2011.

The increase in our trade receivables as of March 31, 2011 as compared to December 31, 2010 is primarily due to the timing of the billing and collection cycles for long-term drilling contracts in Colombia.

The decrease in our unbilled receivables is primarily due to the completion of all our turnkey drilling contracts prior to the quarter end at March 31, 2011, whereas we had unbilled receivables related to one turnkey contract that was in progress at December 31, 2010. This decrease in unbilled receivables was partially offset by an increase in unbilled revenues for long-term drilling contracts in Colombia.

The increase in prepaid expenses and other assets is primarily due to an increase in deferred mobilization costs for domestic drilling rigs that moved between drilling division locations and an increase in prepaid import fees and prepaid contractor fees for our Colombian operations. The increase is partially offset by the decrease in prepaid insurance as of March 31, 2011, as compared to December 31, 2010. We renew and prepay most of our insurance premiums in late October of each year and some in April of each year. As of March 31, 2011, we had amortization of five months of these October insurance premiums, as compared to two months of amortization as of December 31, 2010.

The increase in accounts payable is primarily due to the increase in our capital expenditures during the quarter ended March 31, 2011, as compared to the quarter ended December 31, 2010.

The decrease in accrued payroll and employee related costs is due to the payment of our annual incentive compensation during the three months ended March 31, 2011, which was accrued for at December 31, 2010. The decrease is partially offset by the increase in accrued payroll costs resulting from workforce additions and more payroll days reflected in the accrued payroll at March 31, 2011, as compared to December 31, 2010, due to the timing of pay periods.

The decrease in accrued interest is primarily due to the payment of interest on the Senior Notes in March 2011. The Senior Notes have a coupon interest rate of 9.875% with interest payments due semi-annually on March 15^{th} and September 15^{th}. Therefore, at December 31, 2010, we had accrued for approximately three and a half months of interest on the Senior Notes, whereas at March 31, 2011, we have accrued for less than one month of interest.

The increase in other accrued expenses is primarily due to the net-worth tax accrual for our Colombian operations, which was assessed on January 1, 2011. The total estimated obligation is $7.3 million and will be paid out in eight semi-annual installments over the next four years. Therefore, we have recorded $1.8 million as the current portion of the net-worth tax obligation.

Long-Term Debt and Other Contractual Obligations

The following table includes all our contractual obligations of the types specified below at March 31, 2011 (amounts in thousands):

		Payments Due by Period			
Contractual Obligations	**Total**	**Less than 1 year**	**2-3 years**	**4-5 years**	**More than 5 years**
Long-term debt	$ 294,329	$ 1,279	$ 43,050	$	$ 250,000
Interest on long-term debt	175,679	26,698	50,231	49,375	49,375
Purchase commitments	17,768	17,768			
Operating leases	7,313	2,762	3,704	847	
Restricted cash obligation	1,300	650	650		
Total	$ 496,389	$ 49,157	$ 97,635	$ 50,222	$ 299,375

Long-term debt consists of $42.0 million outstanding under our Revolving Credit Facility, $250 million face amount outstanding under our Senior Notes, $2.3 million outstanding under subordinated notes payable to certain employees that are former shareholders of previously acquired production services businesses and other debt. The $42.0 million outstanding under our Revolving Credit Facility is due at maturity on August 31, 2012. However, we may make principal payments to reduce the outstanding debt balance prior to maturity when cash and working capital is sufficient. The outstanding balance under our Senior Notes has a carrying value of $240.3 million, which represents the $250 million face value net of the $9.7 million of original issue discount, net of amortization. The discount is being amortized over the term of the Senior Notes based on the effective interest method. The Senior Notes will mature on March 15, 2018. Our subordinated notes payable have final maturity dates ranging from August 2011 to April 2013.

Interest payment obligations on our Revolving Credit Facility are estimated based on (1) the 4.23% interest rate that was in effect on April 22, 2011 and (2) the outstanding principal balance of $42.0 million at March 31, 2011 to be paid at maturity in August 2012. Interest payment obligations on our Senior Notes are calculated based on the coupon interest rate of 9.875% due semi-annually in arrears on March 15 and September 15 of each year. Interest payment obligations on our subordinated notes payable are based on interest rates ranging from 6% to 14%, with either quarterly or annual payments of principal and interest through maturity.

Purchase commitments primarily relate to equipment upgrades and purchases of new equipment.

Operating leases consist of lease agreements for office space, operating facilities, equipment and personal property.

As of March 31, 2011, we had restricted cash in the amount of $1.3 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 the remaining two years from the escrow account.

Debt Requirements

The Revolving Credit Facility contains customary mandatory prepayments in respect of asset dispositions, debt incurrence and equity issuances, which are applied to reduce outstanding revolving and swing-line loans and letter of credit exposure. There are no limitations on our ability to access the $225 million borrowing capacity under the Revolving Credit Facility other than maintaining compliance with the covenants. At March 31, 2011, we were in compliance with our financial covenants. Our total consolidated leverage ratio was 2.2 to 1.0, our senior consolidated leverage ratio was 0.4 to 1.0, and our interest coverage ratio was 4.5 to 1.0. The financial covenants contained in our Revolving Credit Facility include the following:

- A maximum total consolidated leverage ratio that cannot exceed:
  - 5.00 to 1.00 as of the end of any fiscal quarter ending March 31, 2011 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 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:

2.00 to 1.00 as of the end of any fiscal quarter ending March 31, 2011 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, our minimum asset coverage ratio 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 Revolving Credit Facility). 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 Revolving Credit Facility 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 Revolving Credit Facility restricts capital expenditures unless (a) after giving effect to such capital expenditure, no event of default would exist under the Revolving Credit Facility and availability under the Revolving Credit Facility 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 $80 million for each fiscal year after 2010. The capital expenditure threshold may be increased by (a) 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 (b) 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 March 31, 2011, our senior consolidated leverage ratio was not greater than 2.50 to 1.00 and, therefore, we were not subject to the capital expenditure threshold restrictions listed above.

The Revolving Credit Facility 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 Revolving Credit Facility 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.

Our obligations under the Revolving Credit Facility 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.

In addition to the financial covenants under our Revolving Credit Facility, the Indenture Agreement for our Senior Notes contains certain restrictions on our ability to:

- pay dividends on stock;
- repurchase stock or redeem subordinated debt or make other restricted payments;
- incur, assume or guarantee additional indebtedness or issue disqualified stock;
- create liens on our assets;
- enter into sale and leaseback transactions;
- pay dividends, engage in loans, or transfer other assets from certain of our subsidiaries;
- consolidate with or merge with or into, or sell all or substantially all of our properties to another person;
- enter into transactions with affiliates; and
- enter into new lines of business.

These covenants are subject to important exceptions and qualifications.

Upon the occurrence of a change of control, holders of the Senior Notes will have the right to require us to purchase all or a portion of the Senior Notes at a price equal to 101% of the principal amount of each Senior Note, together with any accrued and unpaid interest to the date of purchase. Under certain circumstances in connection with asset dispositions, we will be required to use the excess proceeds of asset dispositions to make an offer to purchase the Senior Notes at a price equal to 100% of the principal amount of each Senior Note, together with any accrued and unpaid interest to the date of purchase.

Our Senior Notes are fully and unconditionally guaranteed, jointly and severally, on a senior unsecured basis by our existing domestic subsidiaries, except for Pioneer Services Holdings, LLC, and by certain of our future domestic subsidiaries. The subsidiaries that generally operate our non-U.S. business concentrated in Colombia do not guarantee our Senior Notes. The non-guarantor subsidiaries do not have any payment obligations under the Senior Notes, the guarantees or the Indenture. In the event of a bankruptcy, liquidation or reorganization of any non-guarantor subsidiary, such non-guarantor subsidiary will pay the holders of its debt and other liabilities, including its trade creditors, before it will be able to distribute any of its assets to us. In the future, any non-U.S. subsidiaries, immaterial subsidiaries and subsidiaries that we designate as unrestricted subsidiaries under the Indenture will not guarantee the Senior Notes.

Our Senior Notes are not subject to any sinking fund requirements. As of March 31, 2010, there were no restrictions on the ability of subsidiary guarantors to transfer funds to the parent company, and we were in compliance with all covenants pertaining to our Senior Notes.

Results of Operations

Statement of Operations Analysis

The following table provides information for our operations for the three months ended March 31, 2011 and 2010 (amounts in thousands, except average number of drilling rigs, utilization rate, revenue days and per day information):

	Three Months Ended March 31,	
	2011	**2010**
Drilling Services Division:		
Revenues	$ 99,756	$ 55,817
Operating costs	67,509	45,903
Drilling Services Division margin	$ 32,247	$ 9,914
Average number of drilling rigs	71.0	71.0
Utilization rate	65%	49%
Revenue days	4,151	3,152
Average revenues per day	$ 24,032	$ 17,708
Average operating costs per day	16,263	14,563
Drilling Services Division margin per day	$ 7,769	$ 3,145
Production Services Division:		
Revenues	$ 53,593	$ 30,204
Operating costs	33,228	19,965
Production Services Division margin	$ 20,365	$ 10,239
Combined:		
Revenues	$ 153,349	$ 86,021
Operating costs	100,737	65,868
Combined margin	$ 52,612	$ 20,153
Adjusted EBITDA	$ 31,658	$ 9,239

Drilling Services Division margin represents contract drilling revenues less contract drilling operating costs. Production Services Division margin represents production services revenue less production services operating costs. We believe that Drilling Services Division Margin and Production Services Division margin are useful measures for evaluating financial performance, although they are not measures of financial performance under GAAP. However, Drilling Services Division margin and Production Services Division margin are common measures of operating performance used by investors, financial analysts, rating agencies and Pioneer s management. A reconciliation of Drilling Services Division margin and Production Services Division margin to net loss, as reported is included in the table on the following page. Drilling Services Division margin and Production Services Division margin as presented may not be comparable to other similarly titled measures reported by other companies.

We define Adjusted EBITDA as earnings (loss) before interest income (expense), taxes, depreciation, amortization and any impairments. Although not prescribed under GAAP, we believe the presentation of Adjusted EBITDA is relevant and useful because it helps our investors understand our operating performance and makes it easier to compare our results with those of other companies within our industry. Adjusted EBITDA should not be considered in isolation from or as a substitute for net earnings (loss) as an indication of operating performance or cash flows from operating activities or as a measure of liquidity. A reconciliation of net loss, as reported to Adjusted EBITDA is included in the table below. Adjusted EBITDA, as we calculate it, may not be comparable to Adjusted EBITDA measures reported by other companies. In addition, Adjusted EBITDA does not represent funds available for discretionary use.

	Three Months Ended March 31, 2011	2010
	(amounts in thousands)	
Reconciliation of combined margin and Adjusted EBITDA to net loss:		
Combined margin	$ 52,612	$ 20,153
General and administrative	(14,521)	(11,473)
Bad debt recovery	84	75
Other income (expense)	(6,517)	484
Adjusted EBITDA	31,658	9,239
Depreciation and amortization	(32,256)	(28,871)
Interest income (expense), net	(7,539)	(4,074)
Income tax benefit	2,102	9,159
Impairments		
Net loss, as reported	$ (6,035)	$ (14,547)

Our Drilling Services Division experienced increases in its revenue and operating cost due to higher demand for our drilling services in 2011 as compared to the corresponding period in 2010 as our industry continues to recover from the downturn that bottomed in late 2009.

Our Drilling Services Division s revenues increased by $43.9 million, or 79%, for the quarter ended March 31, 2011, as compared to the corresponding quarter in 2010, due to an increase in utilization rates and drilling revenue rates. During the three months ended March 31, 2011, our drilling rig utilization increased by 33% as compared to the corresponding quarter in 2010, which resulted from an increase in our rig utilization rate from 49% to 65%, and our average contract drilling revenues per day increased by 36%, or $6,324 per day, as compared to the corresponding quarter in 2010.

Our Drilling Services Division s operating costs increased by $21.6 million, or 47%, for the quarter ended March 31, 2011, as compared to the corresponding quarter in 2010, primarily due to the increase in utilization as well as the increase in our operating costs of $1,700 per day, or 12%. The increase in operating costs per day is due to higher average drilling costs per day for our domestic operations, as well as the increase in our Colombian operations during 2011 as compared to 2010, where we have a higher operating cost per day as compared to our domestic operations. As utilization rates increased, average operating costs per day increased due to higher wage rates and repair and maintenance expenses as drilling rigs come out of storage and begin operations.

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. Turnkey drilling contracts also result in higher average revenues per day and higher average operating costs per day when compared to daywork drilling contracts. We completed six and four turnkey drilling contracts during the three months ended March 31, 2011 and 2010, respectively. The following table provides percentages of our drilling revenues by drilling contract type for the three months ended March 31, 2011 and 2010:

	Three Months Ended March 31, 2011	2010
Daywork drilling contracts	92%	93%
Turnkey drilling contracts	8%	7%
Footage drilling contracts		

Our Production Services Division experienced increases in its revenue and operating cost due to higher demand for our wireline services, well services and fishing and rental services during the three months ended March 31, 2011, as compared to the corresponding period in 2010. Our Production Services Division s revenues increased by $23.4 million, or 77%, while operating costs increased $13.3 million, or 66%, for the quarter ended March 31, 2011, as compared to the corresponding quarter in 2010. The increase in our Production Services Division s revenues is due primarily to higher utilization rates and higher revenue rates charged for these services. We have also expanded our operations significantly, adding 32 wireline units, a 48% increase in units since March 31, 2010, resulting in an increase in both revenues and operating costs.

For the three months ended March 31, 2011, our selling, general and administrative expense increased by approximately $3.0 million, or 27%, as compared to the corresponding period in 2010. The increase is primarily due to increases in payroll and compensation related expenses. With the industry downturn during 2009, we experienced a decrease in the demand for our services and we responded with workforce reductions, elimination of wage rate increases and reduced bonus compensation. We have seen an increase in the demand for our services as our industry continues to recover from the industry downturn in 2009. Payroll and compensation related expenses increased during the three months ended March 31, 2011 as compared to the corresponding quarter in 2010 as we have added employees in our corporate office and have accrued for potential higher bonuses anticipated for 2011.

Our other expense increased primarily due to the $7.3 million net-worth tax expense for our Colombian operations which was assessed on January 1, 2011. The increase was partially offset by $0.5 million of income recognized for the ARPSs Call Option during the three months ended March 31, 2011.

For the three months ended March 31, 2011, our depreciation and amortization expense increased by $3.4 million as compared to the corresponding period in 2010. This increase resulted primarily from capital expenditures made to upgrade certain drilling rigs to meet the needs of our customers and obtain new contracts as well as capital expenditures for the acquisition of new wireline units.

Interest expense for the three months ended March 31, 2011 primarily related to the outstanding debt balance for our Senior Notes, while interest expense for the three months ended March 31, 2010 primarily related to the outstanding debt balance under our Revolving Credit Facility. On March 11, 2010, we issued $250 million of Senior Notes with a coupon interest rate of 9.875%. The Senior Notes were sold with an original issue discount that will result in an effective yield to maturity of approximately 10.677%. The proceeds from the issuance of the Senior Notes were immediately used to make a payment of $234.8 million to reduce the outstanding debt balance under the Revolving Credit Facility. The Revolving Credit Facility had a relatively low interest rate of 4.74% as of March 31, 2010, which was based on the LIBOR rate plus a per annum margin. The Senior Notes have a higher interest rate when compared to the Revolving Credit Facility, which resulted in the increase in interest expense for the three months ended March 31, 2011. In addition, interest expense increased in 2011 as compared to 2010 due to an increase in total outstanding debt which was $284.6 million as of March 31, 2011 as compared to $265.8 million as of March 31, 2010.

Our effective income tax rate for the three month period ended March 31, 2011 differs from the federal statutory rate in the United States of 35% primarily due to a lower effective tax rate in foreign jurisdictions, state income taxes and other permanent differences, including the effect of the non-deductible $7.3 million net-worth tax assessed on our Colombian operations as of January 1, 2011.

Inflation

Wage rates for our operations personnel are impacted by inflationary pressures when the demand for drilling and production services increases and the availability of personnel is scarce. With the increase in rig counts beginning in late 2009, we saw a decreased availability of personnel to operate our rigs and therefore we had wage rate increases for drilling rig personnel in certain of our locations of approximately 18% and 16% in February and July 2010, respectively. We have not had similar wage rate increases in 2011, but as the labor markets appear to be tightening, we will continue to evaluate the need for similar wage rate increases in 2011.

Costs for rig repairs and maintenance, rig upgrades and new rig construction are also impacted by inflationary pressures when the demand for drilling services increases. We experienced an increase in these costs of approximately 5% during 2010 and expect similar increases during 2011.

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, *Revenue Recognition*, 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 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 related contract term. 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 completed but not yet invoiced. The assets prepaid expenses and other current assets and other long-term assets include the current and long-term portions of deferred mobilization costs for certain drilling contracts. The liabilities prepaid drilling contracts and other long-term liabilities include the current and long-term portions of deferred mobilization revenues for certain drilling contracts and amounts collected on contracts in excess of revenues recognized. As of March 31, 2011 we had $5.7 million of deferred mobilization revenues, of which the current portion was $3.7 million. The related deferred mobilization costs were $5.6 million, of which the current portion was $3.7 million. Our deferred mobilization costs and revenues primarily related to long-term contracts for our Colombian operations, which are being amortized through the year ending December 31, 2012. Amortization of deferred mobilization revenues was $1.2 million for the three months ended March 31, 2011.

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 collectability 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, *Property, Plant, and Equipment* and ASC Topic 350, *Intangibles Goodwill and Other*. 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 well service 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.

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, 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, well service 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, well service rigs and wireline units over 5 years. Therefore, in the first 5 years of our ownership of a drilling rig, well service 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. 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. We experienced a loss of approximately $0.1 million on one of the turnkey contracts completed during the three months ended March 31, 2011.

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 March 31, 2011. Our unbilled receivables totaled $20.8 million at March 31, 2011, of which $18.4 million related to revenue recognized but not yet billed on daywork drilling contracts in progress at March 31, 2011 and $2.4 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 $0.2 million at March 31, 2011.

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, well service 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 March 31, 2011, we had a $1.2 million deferred tax asset related to the $3.3 million impairment of our ARPSs which represents a capital loss for tax treatment purposes. We can recognize a tax benefit associated with this impairment to the extent of capital gains we expect to earn in future periods. During the year ended December 31, 2010, we recorded a valuation allowance to fully offset our deferred tax asset relating to this capital loss since we believe capital gains are not likely in future periods.

As of March 31, 2011, we had $28.3 million of deferred tax assets related to foreign and domestic net operating loss and AMT credit carryforwards available to reduce future taxable income. In assessing the realizability of our deferred tax assets, we only recognize a tax benefit to the extent of taxable income that we expect to earn in the jurisdiction in future periods. We estimate that our operations will result in taxable income in excess of our net operating losses and we expect to apply the net operating losses against the current year taxable income and taxable income that we have estimated in future periods.

Our accrued insurance premiums and deductibles as of March 31, 2011 include accruals for costs incurred under the self-insurance portion of our health insurance of approximately $1.7 million and our workers compensation, general liability and auto liability insurance of approximately $7.0 million. As of January 1, 2011, we have a deductible of $150,000 per covered individual per year under the health insurance. We have a deductible of $500,000 per occurrence under our workers compensation insurance. 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.

Our stock-based compensation expense includes estimates for certain of our long-term incentive compensation plans which have performance-based award components dependent upon our performance over a set performance period, as compared to the performance of a pre-defined peer group. The accruals for these awards include estimates which affect our stock-based compensation expense, employee related accruals and equity. The accruals are adjusted based on actual achievement levels at the end of the pre-determined performance periods.

Recently Issued Accounting Standards

Multiple Deliverable Revenue Arrangements. In October 2009, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) No. 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 are required to apply this guidance prospectively for revenue arrangements entered into or materially modified after January 1, 2011. The adoption of this new guidance has not had a material impact on our financial position or results of operations.

Business Combinations. In December 2010, the FASB issued ASU No. 2010-29, Business Combinations (Topic 805): *Disclosure of Supplementary Pro Forma Information for Business Combinations A consensus of the FASB Emerging Issues Task Force*. This update provides clarification requiring public companies that have completed material acquisitions to disclose the revenue and earnings of the combined business as if the acquisition took place at the beginning of the comparable prior annual reporting period, and also expands the supplemental pro forma disclosures to include a description of the nature and amount of material, nonrecurring pro forma adjustments directly attributable to the business combination included in the reported pro forma revenue and earnings. We are required to apply this guidance prospectively for business combinations for which the acquisition date is on or after January 1, 2011. The adoption of this new guidance has not had a material impact on our financial position or results of operations.

Recently Enacted Regulation

The Colombian government enacted a tax reform act which, among other things, adopted a one-time, net-worth tax for all Colombian entities, which was assessed on January 1, 2011 and is payable in eight semi-annual installments from 2011 through 2014. Based on our Colombian operations net equity, measured on a Colombian tax basis as of January 1, 2011, our total net-worth tax obligation is approximately $7.3 million, which is not deductible for tax purposes. We recognized this tax obligation in full during the three months ended March 31, 2011 in other expense in our consolidated statement of operations, and in other accrued expenses and other long-term liabilities on our consolidated balance sheet as of March 31, 2011.

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 March 31, 2011, we had $42.0 million outstanding under our Revolving Credit Facility subject to variable interest rate risk. The impact of a 1% increase in interest rates on this amount of debt would have resulted in increased interest expense of approximately $0.1 million and a decrease in net income of approximately $70,000 during the three months ended March 31, 2011.

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.

The impact of currency rate changes on our Colombian Peso denominated transactions and balances resulted in foreign currency gains of $0.1 million for the three months ended March 31, 2011.

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 report. Based on that evaluation, our Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures were effective as of March 31, 2011 to ensure that information required to be disclosed in our reports filed or submitted under the Exchange Act is (1) recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission s rules and forms and (2) 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 March 31, 2011 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 March 31, 2011.

Period	**Total Number of Shares Purchased (1)**	**Average Price Paid per Share (2)**	**Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs**	**Maximum Number of Shares that May Yet Be Purchased Under the Plans or Programs**
January 1 - January 31	362	$ 8.55		
February 1 - February 28	5,612	$ 9.01		
March 1 - March 31	13,407	$ 11.67		
Total	19,381	$ 10.84		

(1) The shares indicated consist of shares of our common stock tendered by employees to the Company during the three months ended March 31, 2011, 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 5. Other Information

Not applicable.

ITEM 6. EXHIBITS

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

Exhibit Number		Description
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)).
4.2*	-	Indenture, dated March 11, 2010, by and among Pioneer Drilling Company, the subsidiary guarantors party thereto and Wells Fargo Bank, National Association, as trustee (Form 8-K dated March 12, 2010, (File No. 1-8182, Exhibit 4.1)).
4.3*	-	Registration Rights Agreement, dated March 11, 2010, by and among Pioneer Drilling Company, the subsidiary guarantors party thereto and the initial purchasers party thereto (Form 8-K dated March 12, 2010, (File No. 1-8182, Exhibit 4.2)).
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 by reference to the filing indicated.

** 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 Officer)

Dated: May 5, 2011

Index to Exhibits

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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)).
4.2*	-	Indenture, dated March 11, 2010, by and among Pioneer Drilling Company, the subsidiary guarantors party thereto and Wells Fargo Bank, National Association, as trustee (Form 8-K dated March 12, 2010 (File No. 1-8182, Exhibit 4.1)).
4.3*	-	Registration Rights Agreement, dated March 11, 2010, by and among Pioneer Drilling Company, the subsidiary guarantors party thereto and the initial purchasers party thereto (Form 8-K dated March 12, 2010 (File No. 1-8182, Exhibit 4.2)).
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 by reference to the filing indicated.
** Filed herewith.
\# Furnished herewith.