BERKERY ROSEMARY T
Form 4
April 05, 2012

# FORM 4

Check this box if no longer subject to Section 16. Form 4 or Form 5 obligations may continue. *See* Instruction 1(b).

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

**STATEMENT OF CHANGES IN BENEFICIAL OWNERSHIP OF SECURITIES**

Filed pursuant to Section 16(a) of the Securities Exchange Act of 1934, Section 17(a) of the Public Utility Holding Company Act of 1935 or Section 30(h) of the Investment Company Act of 1940

OMB APPROVAL

| | |
|---|---|
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(Print or Type Responses)

1. Name and Address of Reporting Person *
BERKERY ROSEMARY T
(Last) (First) (Middle)
6700 LAS COLINAS BOULEVARD
(Street)
IRVING, TX 75039
(City) (State) (Zip)

2. Issuer Name **and** Ticker or Trading Symbol
FLUOR CORP [FLR]

3. Date of Earliest Transaction (Month/Day/Year)
04/03/2012

4. If Amendment, Date Original Filed(Month/Day/Year)

5. Relationship of Reporting Person(s) to Issuer
(Check all applicable)
__X__ Director _____ 10% Owner
_____ Officer (give title below) _____ Other (specify below)

6. Individual or Joint/Group Filing(Check Applicable Line)
_X_ Form filed by One Reporting Person
___ Form filed by More than One Reporting Person

**Table I - Non-Derivative Securities Acquired, Disposed of, or Beneficially Owned**

| 1.Title of Security (Instr. 3) | 2. Transaction Date (Month/Day/Year) | 2A. Deemed Execution Date, if any (Month/Day/Year) | 3. Transaction Code (Instr. 8) | | 4. Securities Acquired (A) or Disposed of (D) (Instr. 3, 4 and 5) | | | 5. Amount of Securities Beneficially Owned Following Reported Transaction(s) (Instr. 3 and 4) | 6. Ownership Form: Direct (D) or Indirect (I) (Instr. 4) | 7. Nature of Indirect Beneficial Ownership (Instr. 4) |
|---|---|---|---|---|---|---|---|---|---|---|
| | | | Code | V | Amount | (A) or (D) | Price | | | |

Reminder: Report on a separate line for each class of securities beneficially owned directly or indirectly.

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SEC 1474 (9-02)

**Table II - Derivative Securities Acquired, Disposed of, or Beneficially Owned**
**(*e.g.*, puts, calls, warrants, options, convertible securities)**

| 1. Title of Derivative Security | 2. Conversion or Exercise | 3. Transaction Date (Month/Day/Year) | 3A. Deemed Execution Date, if any | 4. Transaction Code | 5. Number of Derivative Securities | 6. Date Exercisable and Expiration Date (Month/Day/Year) | 7. Title and Amount of Underlying Securities (Instr. 3 and 4) | 8. Pr Deri Secu |
|---|---|---|---|---|---|---|---|---|

| (Instr. 3) | Price of Derivative Security | | (Month/Day/Year) | (Instr. 8) | | Acquired (A) or Disposed of (D) (Instr. 3, 4, and 5) | | | | | | (Inst |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | Code | V | (A) | (D) | Date Exercisable | Expiration Date | Title | Amount or Number of Shares | |
| Phantom stock units | (1) | 04/03/2012 | | A | | 6.8894 | | (2) | (2) | Common Stock | 6.8894 | $ 6 |

# Reporting Owners

| Reporting Owner Name / Address | Relationships | | | |
|---|---|---|---|---|
| | Director | 10% Owner | Officer | Other |
| BERKERY ROSEMARY T<br>6700 LAS COLINAS BOULEVARD<br>IRVING, TX 75039 | X | | | |

# Signatures

| /s/ Eric P. Helm by Power of Attorney | 04/05/2012 |
|---|---|
| **Signature of Reporting Person | Date |

# Explanation of Responses:

* If the form is filed by more than one reporting person, *see* Instruction 4(b)(v).

** Intentional misstatements or omissions of facts constitute Federal Criminal Violations. *See* 18 U.S.C. 1001 and 15 U.S.C. 78ff(a).

**(1)** Each phantom stock unit is the economic equivalent of one share of Fluor common stock.

**(2)** These phantom units were acquired under the Fluor Corporation 409A Deferred Directors' Fees program (the "Program") through the crediting of dividends and are to be settled in cash. Distributions will be made, at the election of the reporting person, either (i) in the distribution year specified by the reporting person or (ii) upon the reporting person's termination of service as a director, death or disability, in a single lump sum payment or annual installment payments over a period of two to ten years. The reporting person may transer the phantom units into an alternative investment at any time. However, unvested units granted as matching contributions under the Program shall be forfeited by the reporting person to the extent attributable to the transferred units.

Note: File three copies of this Form, one of which must be manually signed. If space is insufficient, *see* Instruction 6 for procedure.
Potential persons who are to respond to the collection of information contained in this form are not required to respond unless the form displays a currently valid OMB number. ensed Consolidated Statement of Cash Flows

**(Unaudited)**

| | Six Months Ended June 30, 2012 | 2011 |
|---|---|---|
| | (In thousands) | |
| **Cash flows from operating activities:** | | |
| Net income | $ 92,484 | $ 26,502 |
| Adjustments to reconcile net income to net cash provided by operating activities: | | |
| Depreciation, depletion and amortization | 83,099 | 26,912 |

| | | |
|---|---|---|
| Impairment of oil and gas properties | 2,571 | 2,917 |
| Deferred income taxes | 55,161 | 16,069 |
| Derivative instruments | (56,009) | 4,119 |
| Stock-based compensation expenses | 3,898 | 1,571 |
| Debt discount amortization and other | 1,265 | 648 |
| Working capital and other changes: | | |
| Change in accounts receivable | (26,840) | (19,945) |
| Change in inventory | (21,636) | (65) |
| Change in prepaid expenses | 1,500 | (254) |
| Change in other current assets | 490 | (211) |
| Change in other assets | (7,365) | (103) |
| Change in accounts payable and accrued liabilities | 40,022 | 43,612 |
| Change in other current liabilities | 2,470 | |
| Change in other liabilities | 750 | 323 |
| Net cash provided by operating activities | 171,860 | 102,095 |
| **Cash flows from investing activities:** | | |
| Capital expenditures | (440,781) | (212,267) |
| Derivative settlements | (2,465) | (4,652) |
| Purchases of short-term investments | | (164,913) |
| Redemptions of short-term investments | 19,994 | 39,974 |
| Advances to joint interest partners | 1,978 | 983 |
| Advances from joint interest partners | 19,380 | 5,851 |
| Net cash used in investing activities | (401,894) | (335,024) |
| **Cash flows from financing activities:** | | |
| Proceeds from issuance of senior notes | | 400,000 |
| Purchases of treasury stock | (1,206) | (559) |
| Debt issuance costs | (746) | (10,027) |
| Net cash (used in) provided by financing activities | (1,952) | 389,414 |
| (Decrease) increase in cash and cash equivalents | (231,986) | 156,485 |
| **Cash and cash equivalents:** | | |
| Beginning of period | 470,872 | 143,520 |
| End of period | $ 238,886 | $ 300,005 |
| **Supplemental non-cash transactions:** | | |
| Change in accrued capital expenditures | $ 104,486 | $ (6,676) |
| Change in asset retirement obligations | 4,185 | 2,357 |

The accompanying notes are an integral part of these condensed consolidated financial statements.

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**OASIS PETROLEUM INC.**

**Notes to Condensed Consolidated Financial Statements (Unaudited)**

**1. Organization and Operations of the Company**

***Organization***

Oasis Petroleum Inc. ( Oasis or the Company ) was formed on February 25, 2010, pursuant to the laws of the State of Delaware, to become a holding company for Oasis Petroleum LLC ( OP LLC ), the Company s predecessor, which was formed as a Delaware limited liability company on February 26, 2007. In connection with its initial public offering in June 2010 and related corporate reorganization, the Company acquired all of the outstanding membership interests in OP LLC in exchange for shares of the Company s common stock. In May 2007, the Company formed Oasis Petroleum North America LLC ( OPNA ), a Delaware limited liability company, to conduct its domestic oil and natural gas exploration and production activities. In April 2008, the Company formed Oasis Petroleum International LLC ( OPI ), a Delaware limited liability company, to conduct business development activities outside of the United States of America. As of June 30, 2012, OPI had no business activities or material assets. In June 2011, the Company formed Oasis Well Services LLC ( OWS ), a Delaware limited liability company, to provide well services to OPNA. In July 2011, the Company formed Oasis Petroleum Marketing LLC ( OPM ), a Delaware limited liability company, to provide marketing services to OPNA.

***Nature of Business***

The Company is an independent exploration and production company focused on the acquisition and development of unconventional oil and natural gas resources in the Williston Basin. The Company s proved and unproved oil and natural gas properties are located in the Montana and North Dakota areas of the Williston Basin and are owned by OPNA. The Company also operates businesses that are complementary to its primary development and production activities, including a marketing business (OPM) and a well services business (OWS).

**2. Summary of Significant Accounting Policies**

***Basis of Presentation***

The accompanying condensed consolidated financial statements of the Company include the accounts of Oasis and its wholly owned subsidiaries: OP LLC, OPNA, OPI, OWS and OPM. The accompanying condensed consolidated financial statements of the Company have not been audited by the Company s independent registered public accounting firm, except that the condensed consolidated balance sheet at December 31, 2011 is derived from audited financial statements. All significant intercompany transactions have been eliminated in consolidation. Certain reclassifications of prior year balances have been made to conform such amounts to current year classifications. These reclassifications have no impact on net income. In the opinion of management, all adjustments, consisting of normal recurring adjustments, necessary for the fair presentation have been included. In preparing the accompanying condensed consolidated financial statements, management has made certain estimates and assumptions that affect reported amounts in the condensed consolidated financial statements and disclosures of contingencies. Actual results may differ from those estimates. The results for interim periods are not necessarily indicative of annual results.

These interim financial statements have been prepared pursuant to the rules and regulations of the Securities and Exchange Commission ( SEC ) regarding interim financial reporting. Certain disclosures have been condensed or omitted from these financial statements. Accordingly, they do not include all of the information and notes required by accounting principles generally accepted in the United States of America ( GAAP ) for complete consolidated financial statements and should be read in conjunction with the Company s audited consolidated financial statements and notes thereto included in the Company s Annual Report on Form 10-K for the year ended December 31, 2011 ( 2011 Annual Report ).

***Significant Accounting Policies***

There have been no material changes to the Company s critical accounting policies and estimates from those disclosed in the 2011 Annual Report.

**3. Inventory**

Equipment and materials consist primarily of tubular goods, well equipment to be used in future drilling or repair operations and well fracturing equipment, all of which are stated at the lower of cost or market with cost determined on an average cost method. Crude oil inventories include oil in tank and line fill and are valued at the lower of average cost or market value. Inventory consists of the following:

| | June 30, 2012 | December 31, 2011 |
|---|---|---|
| | (In thousands) | |
| Equipment and materials | $ 16,869 | $ 2,709 |
| Crude oil inventory | 2,681 | 834 |
| Total inventory | $ 19,550 | $ 3,543 |

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**4. Property, Plant and Equipment**

The following table sets forth the Company s property, plant and equipment:

| | June 30, 2012 | December 31, 2011 |
|---|---|---|
| | (In thousands) | |
| Proved oil and gas properties (1) | $ 1,691,964 | $ 1,152,532 |
| Less: Accumulated depreciation, depletion, amortization and impairment | (257,607) | (174,948) |
| Proved oil and gas properties, net | 1,434,357 | 977,584 |
| Unproved oil and gas properties | 77,606 | 82,825 |
| Oil and gas properties, net | 1,511,963 | 1,060,409 |
| Other property and equipment | 41,333 | 20,859 |
| Less: Accumulated depreciation | (3,922) | (1,313) |
| Other property and equipment, net | 37,411 | 19,546 |
| Total property, plant and equipment, net | $ 1,549,374 | $ 1,079,955 |

(1) Included in the Company s proved oil and gas properties are estimates of future asset retirement costs of $15.2 million and $11.4 million at June 30, 2012 and December 31, 2011, respectively. In addition, the Company s proved oil and gas properties include capitalized interest of $4.7 million and $3.1 million at June 30, 2012 and December 31, 2011, respectively.

As a result of expiring leases and periodic assessments of unproved properties, the Company recorded non-cash impairment charges on its unproved oil and gas properties of $2.2 million and $2.6 million for the three and six months ended June 30, 2012, respectively, and $1.5 million and $2.9 million for the three and six months ended June 30, 2011, respectively. No impairment charges on proved oil and natural gas properties were recorded for the three and six months ended June 30, 2012 or 2011.

**5. Fair Value Measurements**

In accordance with the Financial Accounting Standards Board s ( FASB ) authoritative guidance on fair value measurements, the Company s financial assets and liabilities are measured at fair value on a recurring basis. The Company recognizes its non-financial assets and liabilities, such as asset retirement obligations and proved oil and natural gas properties upon impairment, at fair value on a non-recurring basis.

As defined in the authoritative guidance, fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date ( exit price ). To estimate fair value, the Company utilizes market data or assumptions that market participants would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable, market corroborated or generally unobservable.

The authoritative guidance establishes a fair value hierarchy that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities ( Level 1 measurements) and the lowest priority to unobservable inputs ( Level 3 measurements). The three levels of the fair value hierarchy are as follows:

*Level 1* Unadjusted quoted prices are available in active markets for identical assets or liabilities as of the reporting date. Active markets are those in which transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis.

*Level 2* Pricing inputs, other than unadjusted quoted prices in active markets included in Level 1, are either directly or indirectly observable as of the reporting date. Level 2 includes those financial instruments that are valued using models or other valuation methodologies. These models are primarily industry-standard models that consider various assumptions, including quoted forward prices for commodities, time value, volatility factors and current market and contractual prices for the underlying instruments, as well as other relevant economic measures. Substantially all of these assumptions are observable in the marketplace throughout the full term of the instrument and can be derived from observable data or are supported by observable levels at which transactions are executed in the marketplace.

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*Level 3* Pricing inputs are generally less observable from objective sources, requiring internally developed valuation methodologies that result in management s best estimate of fair value.

***Financial Assets and Liabilities***

As required, financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. The Company s assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels. The following tables set forth by level within the fair value hierarchy the Company s financial assets and liabilities that were accounted for at fair value on a recurring basis:

| | At fair value as of June 30, 2012 | | | |
|---|---|---|---|---|
| | Level 1 | Level 2 | Level 3 | Total |
| | (In thousands) | | | |
| Assets: | | | | |
| Money market funds | $ 145,609 | $ | $ | $ 145,609 |
| Commodity derivative instruments (see Note 6) | | 53,424 | | 53,424 |
| Total assets | $ 145,609 | $ 53,424 | $ | $ 199,033 |

| | At fair value as of December 31, 2011 | | | |
|---|---|---|---|---|
| | Level 1 | Level 2 | Level 3 | Total |
| | (In thousands) | | | |
| Assets: | | | | |
| Money market funds | $ 250,419 | $ | $ | $ 250,419 |
| Commodity derivative instruments (see Note 6) | | | 4,362 | 4,362 |
| Total assets | $ 250,419 | $ | $ 4,362 | $ 254,781 |
| Liabilities: | | | | |
| Commodity derivative instruments (see Note 6) | $ | $ | $ 9,412 | $ 9,412 |
| Total liabilities | $ | $ | $ 9,412 | $ 9,412 |

The Level 1 instruments presented in the tables above consist of money market funds included in cash and cash equivalents on the Company s Condensed Consolidated Balance Sheet at June 30, 2012 and December 31, 2011. The Company s money market funds represent cash equivalents backed by the assets of high-quality major banks and financial institutions. The Company identified the money market funds as Level 1 instruments due to the fact that the money market funds have daily liquidity, quoted prices for the underlying investments can be obtained and there are active markets for the underlying investments.

The Level 2 and Level 3 instruments presented in the tables above consist of oil collars, put spreads and deferred premium puts. The fair values of the Company s oil collars and deferred premium puts are based upon a third-party preparer s calculation using mark-to-market valuation reports provided by the Company s counterparties for monthly settlement purposes to determine the valuation of its derivative instruments. The Company has the third-party preparer evaluate other readily available market prices for its derivative contracts as there is an active market for these contracts. The third-party preparer performs its independent valuation using an options pricing model similar to Black-Scholes. The significant inputs used are crude oil prices, volatility, skew, discount rate and the contract terms of the derivative instruments. However, the Company does not have access to the specific proprietary valuation models or inputs used by its counterparties or third-party preparer. The determination of the fair values also incorporates a credit adjustment for non-performance risk, as required by GAAP. The Company calculated the credit adjustment for derivatives in an asset position using current credit default swap values for each counterparty. The credit adjustment for derivatives in a liability position is based on the Company s market credit spread. Based on these calculations, the Company recorded a downward adjustment to the fair value of its net derivative asset in the amount of $0.3 million at June 30, 2012 and a downward adjustment to the fair value of its net derivative liability in the amount of $0.3 million at December 31, 2011.

The Company has adopted the FASB s authoritative guidance amending certain accounting and disclosure requirements related to fair value measurements. The guidance clarifies and modifies some fair value measurement principles under GAAP, including a change in the valuation premise and the application of premiums and discounts, and contains some new disclosure requirements under GAAP. The guidance had no impact on the Company s financial position, cash flows or results of operations for the six months ended June 30, 2012.

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The following table presents a reconciliation of the changes in fair value of the derivative instruments classified as Level 3 in the fair value hierarchy for the periods presented.

| | 2012 | 2011 |
|---|---|---|
| | (In thousands) | |
| Balance as of January 1 | $ (5,050) | $ (10,486) |
| Total gains or (losses) (realized or unrealized): | | |
| Included in earnings | | (4,119) |
| Included in other comprehensive income | | |
| Settlements | | 4,652 |
| Transfers in and out of Level 3 (1) | 5,050 | |
| Balance as of June 30 | $ | $ (9,953) |
| Change in unrealized losses included in earnings relating to derivatives still held at June 30 | $ | $ 533 |

(1) During the first six months of 2012, the inputs used to value the Company s commodity derivative instruments were directly or indirectly observable and those contracts were transferred to Level 2.

***Fair Value of Other Financial Instruments***

The Company s financial instruments, including certain cash and cash equivalents, short-term investments, accounts receivable and accounts payable, are carried at amortized cost, which approximates cost and fair value due to the short-term maturity of these instruments. At June 30, 2012, the Company s cash equivalents were all Level 1 assets. The carrying amount of the Company s long-term debt (senior unsecured notes due 2019 and 2021 see Note 7) reported in the Condensed Consolidated Balance Sheet at June 30, 2012 is $800.0 million, with a fair value of $806.0 million. The Company s unsecured notes are publicly traded and therefore categorized as a Level 1 asset.

***Nonfinancial Assets and Liabilities***

*Asset retirement obligations.* The carrying amount of the Company s asset retirement obligations ( ARO ) in the Condensed Consolidated Balance Sheet at June 30, 2012 is $17.3 million (see Note 8 Asset Retirement Obligations). The Company determines the ARO by calculating the present value of estimated cash flows related to the liability. Estimating the future ARO requires management to make estimates and judgments regarding timing and existence of a liability, as well as what constitutes adequate restoration. Inherent in the fair value calculation are numerous assumptions and judgments, including the ultimate costs, inflation factors, credit adjusted discount rates, timing of settlement and changes in the legal, regulatory, environmental and political environments. These assumptions represent Level 3 inputs. To the extent future revisions to these assumptions impact the fair value of the existing ARO liability, a corresponding adjustment is made to the related asset.

*Impairment.* The Company reviews its proved oil and natural gas properties for impairment whenever events and circumstances indicate that a decline in the recoverability of their carrying value may have occurred. The Company estimates the expected undiscounted future cash flows of its oil and natural gas properties and compares such undiscounted future cash flows to the carrying amount of the oil and natural gas properties to determine if the carrying amount is recoverable. If the carrying amount exceeds the estimated undiscounted future cash flows, the Company will adjust the carrying amount of the oil and natural gas properties to fair value. The factors used to determine fair value are subject to management s judgment and expertise and include, but are not limited to, recent sales prices of comparable properties, the present value of future cash flows, net of estimated operating and development costs using estimates of proved reserves, future commodity pricing, future production estimates, anticipated capital expenditures and various discount rates commensurate with the risk and current market conditions associated with realizing the expected cash flows projected. These assumptions represent Level 3 inputs. No impairment charges on proved oil and natural gas properties were recorded for the three months ended June 30, 2012 or 2011.

**6. Derivative Instruments**

The Company utilizes derivative financial instruments to manage risks related to changes in oil prices. As of June 30, 2012, the Company utilized put spreads, two-way collar options and three-way collar options to reduce the volatility of oil prices on a significant portion of the Company s future expected oil production. All derivative instruments are recorded on the balance sheet as either assets or liabilities measured at fair value (see Note 5 Fair Value Measurements). Derivative assets and liabilities arising from the Company s derivative contracts with the same counterparty are also reported on a net basis, as all counterparty contracts provide for net settlement. The Company has not designated any derivative instruments as hedges for accounting purposes and does not enter into such instruments for speculative trading purposes. If a derivative does not qualify as a hedge or is not designated as a hedge, the changes in fair value, both realized and unrealized, are recognized in the Other Income (Expense) section of the Condensed Consolidated Statement of Operations as a gain or loss on derivative instruments. The Company s cash flow is only impacted when the actual settlements under the derivative contracts result in making or receiving a payment to or from the counterparty. These cash settlements are reflected as investing activities in the Company s Condensed Consolidated Statement of Cash Flows.

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As of June 30, 2012, the Company had the following outstanding commodity derivative instruments, all of which settle monthly based on the average West Texas Intermediate crude oil index price:

| Settlement Period | Derivative Instrument | Total Notional Amount of Oil (Barrels) | Average Sub-Floor Price | Average Floor Price | Average Ceiling Price | Fair Value Asset (Liability) (In thousands) |
|---|---|---|---|---|---|---|
| 2012 | Two-Way Collars | 1,189,500 | | $ 89.23 | $ 108.76 | $ 7,906 |
| 2012 | Three-Way Collars | 1,860,000 | $ 66.39 | $ 90.33 | $ 109.70 | 12,093 |
| 2013 | Two-Way Collars | 201,500 | | $ 89.23 | $ 108.76 | 1,533 |
| 2013 | Three-Way Collars | 2,023,420 | $ 65.30 | $ 92.51 | $ 112.63 | 13,978 |
| 2013 | Put Spreads | 1,717,080 | $ 70.71 | $ 91.24 | | 12,853 |
| 2014 | Three-Way Collars | 827,030 | $ 71.08 | $ 92.58 | $ 114.15 | 3,714 |
| 2014 | Put Spreads | 150,970 | $ 71.03 | $ 91.03 | | 1,104 |
| 2015 | Three-Way Collars | 62,000 | $ 72.50 | $ 92.50 | $ 114.40 | 243 |
| | | | | | | $ 53,424 |

The following table summarizes the location and fair value of all outstanding commodity derivative instruments recorded in the balance sheet for the periods presented:

**Fair Value of Derivative Instrument Assets (Liabilities)**

| Instrument Type | Balance Sheet Location | | Fair Value June 30, 2012 (In thousands) | Fair Value December 31, 2011 (In thousands) |
|---|---|---|---|---|
| Crude oil collar | Derivative instruments | current assets | $ 35,257 | $ |
| Crude oil collar | Derivative instruments | non-current assets | 18,167 | 4,362 |
| Crude oil collar | Derivative instruments | current liabilities | | (5,907) |
| Crude oil collar | Derivative instruments | non-current liabilities | | (3,505) |
| Total derivative instruments | | | $ 53,424 | $ (5,050) |

The following table summarizes the location and amounts of realized and unrealized gains and losses from the Company s commodity derivative instruments for the periods presented:

| | Income Statement Location | Three Months Ended June 30, 2012 (In thousands) | Three Months Ended June 30, 2011 (In thousands) | Six Months Ended June 30, 2012 (In thousands) | Six Months Ended June 30, 2011 (In thousands) |
|---|---|---|---|---|---|
| Change in unrealized gain/loss on derivative instruments | Net gain (loss) on derivative instruments | $ 75,769 | $ 31,687 | $ 58,474 | $ 533 |
| Realized loss on derivative instruments | Net gain (loss) on derivative instruments | (1,174) | (4,140) | (2,465) | (4,652) |
| Total net gain (loss) on derivative instruments | | $ 74,595 | $ 27,547 | $ 56,009 | $ (4,119) |

**7. Long-Term Debt**

*Senior unsecured notes.* During 2011, the Company issued $400.0 million of 7.25% senior unsecured notes due February 1, 2019 (the 2019 Notes ) and $400.0 million of 6.5% senior unsecured notes due November 1, 2021 (the 2021 Notes , and together with the 2019 Notes, the Notes ). Interest on the Notes is payable semi-annually in arrears. The Notes are guaranteed on a senior unsecured basis by the Company s material subsidiaries (the Guarantors ). These guarantees are full and unconditional and joint and several among the Guarantors. The issuance of these Notes resulted in aggregate net proceeds to the Company of approximately $783.4 million.

The Notes were issued under indentures containing provisions that are substantially the same, as amended and supplemented by supplemental indentures (collectively the Indentures ), among the Company, the Guarantors and U.S. Bank National Association, as trustee (the Trustee ). The Company has certain options to redeem up to 35% of the Notes at a certain redemption price based on a percentage of the principal amount, plus accrued and unpaid interest to the redemption date, with the proceeds of certain equity offerings so long as the redemption occurs within 180 days of completing such equity offering and at least 65% of the aggregate principal amount of the Notes remains outstanding after such redemption. Prior to certain dates, the Company has the option to redeem some or all of the Notes for cash at certain redemption prices equal to a certain percentage of their principal amount plus an applicable make-whole premium and accrued and unpaid interest to the redemption date. The Company estimates that the fair value of these options is immaterial at June 30, 2012.

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The Indentures restrict the Company s ability and the ability of certain of its subsidiaries to: (i) incur additional debt or enter into sale and leaseback transactions; (ii) pay distributions on, redeem or repurchase equity interests; (iii) make certain investments; (iv) incur liens; (v) enter into transactions with affiliates; (vi) merge or consolidate with another company; and (vii) transfer and sell assets. These covenants are subject to certain exceptions and qualifications. If at any time when the Notes are rated investment grade by both Moody s Investors Service, Inc. and Standard & Poor s Ratings Services and no Default (as defined in the Indentures) has occurred and is continuing, many of such covenants will terminate and the Company and its subsidiaries will cease to be subject to such covenants.

The Indentures contain customary events of default, including:

- default in any payment of interest on any Note when due, continued for 30 days;
- default in the payment of principal or premium, if any, on any Note when due;
- failure by the Company to comply with its other obligations under the Indentures, in certain cases subject to notice and grace periods;
- payment defaults and accelerations with respect to other indebtedness of the Company and its Restricted Subsidiaries (as defined in the Indentures) in the aggregate principal amount of $10.0 million or more;
- certain events of bankruptcy, insolvency or reorganization of the Company or a Significant Subsidiary (as defined in the Indentures) or group of Restricted Subsidiaries that, taken together, would constitute a Significant Subsidiary;
- failure by the Company or any Significant Subsidiary or group of Restricted Subsidiaries that, taken together, would constitute a Significant Subsidiary to pay certain final judgments aggregating in excess of $10.0 million within 60 days; and
- any guarantee of the Notes by a Guarantor ceases to be in full force and effect, is declared null and void in a judicial proceeding or is denied or disaffirmed by its maker.

*Senior secured revolving line of credit.* OP LLC, as parent, and OPNA, as borrower, entered into a credit agreement dated June 22, 2007 (as amended and restated, the Amended Credit Facility ). The Amended Credit Facility is restricted to the borrowing base, which is reserve-based and subject to semi-annual redeterminations on April 1 and October 1 of each year. Borrowings under the Amended Credit Facility are collateralized by perfected first priority liens and security interests on substantially all of the Company s assets, including mortgage liens on oil and natural gas properties having at least 80% of the reserve value as determined by reserve reports. On April 3, 2012, the Company entered into its sixth amendment to its Amended Credit Facility. This amendment added two new lenders to the bank group. All other terms and conditions of the Amended Credit Facility remained the same, including the October 6, 2016 maturity date and the $1 billion senior secured revolving line of credit. In connection with the sixth amendment, the semi-annual redetermination of the borrowing base was also completed on April 3, 2012, which resulted in the borrowing base of the Amended Credit Facility increasing from $350 million to $500 million. Effective April 20, 2012, the Company executed an agreement consenting to the resignation of BNP Paribas as the administrative agent and a lender under the Amended Credit Facility. Wells Fargo was appointed successor administrative agent and assumed the credit commitment of BNP Paribas. BNP Paribas remains as a counterparty for the Company s commodity derivative instruments. In addition, on June 25, 2012, the Company s lenders waived the mandatory reduction of the Company s borrowing base that otherwise would have occurred as a result of the Company s issuance of senior unsecured notes in July 2012 (see Note 13 Subsequent Events).

Borrowings under the Amended Credit Facility are subject to varying rates of interest based on (1) the total outstanding borrowings (including the value of all outstanding letters of credit) in relation to the borrowing base and (2) whether the loan is a London interbank offered rate ( LIBOR ) loan or a domestic bank prime interest rate loan (defined in the Amended Credit Facility as an Alternate Based Rate or ABR loan). As of June 30, 2012, any outstanding LIBOR and ABR loans would have borne their respective interest rates plus the applicable margin indicated in the following table:

| Ratio of Total Outstanding Borrowings to Borrowing Base | Applicable Margin for LIBOR Loans | Applicable Margin for ABR Loans |
|---|---|---|
| Less than .25 to 1 | 1.50% | 0.00% |
| Greater than or equal to .25 to 1 but less than .50 to 1 | 1.75% | 0.25% |
| Greater than or equal to .50 to 1 but less than .75 to 1 | 2.00% | 0.50% |
| Greater than or equal to .75 to 1 but less than .90 to 1 | 2.25% | 0.75% |
| Greater than .90 to 1 but less than or equal 1 | 2.50% | 1.00% |

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An ABR loan may be repaid at any time before the scheduled maturity of the Amended Credit Facility upon the Company providing advance notification to the lenders under the Amended Credit Facility (the Lenders ). Interest is paid quarterly on ABR loans based on the number of days an ABR loan is outstanding as of the last business day in March, June, September and December. The Company has the option to convert an ABR loan to a LIBOR-based loan upon providing advance notification to the Lenders. The minimum available loan term is one month and the maximum loan term is six months for LIBOR-based loans. Interest for LIBOR loans is paid upon maturity of the loan term. Interim interest is paid every three months for LIBOR loans that have loan terms greater than three months in duration. At the end of a LIBOR loan term, the Amended Credit Facility allows the Company to elect to repay the borrowing, continue a LIBOR loan with the same or a differing loan term or convert the borrowing to an ABR loan.

On a quarterly basis, the Company also pays a 0.375% annualized commitment fee on the average amount of borrowing base capacity not utilized during the quarter and fees calculated on the average amount of letter of credit balances outstanding during the quarter.

The Amended Credit Facility contains covenants that include, among others:

- a prohibition against incurring debt, subject to permitted exceptions;
- a prohibition against making dividends, distributions and redemptions, subject to permitted exceptions;
- a prohibition against making investments, loans and advances, subject to permitted exceptions;
- restrictions on creating liens and leases on the assets of the Company and its subsidiaries, subject to permitted exceptions;
- restrictions on merging and selling assets outside the ordinary course of business;
- restrictions on use of proceeds, investments, transactions with affiliates or change of principal business;
- a provision limiting oil and natural gas derivative financial instruments;
- a requirement that the Company not allow a ratio of Total Net Debt (as defined in the Amended Credit Facility) to consolidated EBITDAX (as defined in the Amended Credit Facility) to be greater than 4.0 to 1.0 for the four quarters ended on the last day of each quarter; and
- a requirement that the Company maintain a Current Ratio (as defined in the Amended Credit Facility) of consolidated current assets (with exclusions as described in the Amended Credit Facility) to consolidated current liabilities (with exclusions as described in the Amended Credit Facility) of not less than 1.0 to 1.0 as of the last day of any fiscal quarter.

The Amended Credit Facility contains customary events of default. If an event of default occurs and is continuing, the Lenders may declare all amounts outstanding under the Amended Credit Facility to be immediately due and payable.

As of June 30, 2012, the Company had no borrowings and no outstanding letters of credit issued under the Amended Credit Facility, resulting in an unused borrowing base capacity of $500 million. The Company was in compliance with the financial covenants of the Amended Credit Facility as of June 30, 2012.

*Deferred financing costs.* As of June 30, 2012, the Company had $25.2 million of deferred financing costs related to the Amended Credit Facility and the senior unsecured notes. The deferred financing costs are included in deferred costs and other assets on the Company s Condensed Consolidated Balance Sheet at June 30, 2012 and are being amortized over the respective terms of the Amended Credit Facility and the senior unsecured notes. The amortization of these deferred financing costs is included in interest expense on the Company s Condensed Consolidated Statement of Operations.

**8. Asset Retirement Obligations**

The following table reflects the changes in the Company s ARO during the six months ended June 30, 2012:

| | | |
|---|---|---|
| | | **(In thousands)** |
| Balance at December 31, 2011 | $ | 13,075 |
| Liabilities incurred during period | | 2,812 |
| Liabilities settled during period | | |
| Accretion expense during period (1) | | 389 |
| Revisions to estimates | | 984 |
| Balance at June 30, 2012 | $ | 17,260 |

(1) Included in depreciation, depletion and amortization on the Company s Condensed Consolidated Statement of Operations.

At June 30, 2012, the current portion of the total ARO balance was approximately $0.3 million and is included in accrued liabilities on the Company s Condensed Consolidated Balance Sheet.

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**9. Income Taxes**

The Company s effective tax rate for the three and six months ended June 30, 2012 was 37.4%, and the Company s effective tax rate for the three and six months ended June 30, 2011 was 37.8%, which were consistent with the statutory tax rate applicable to the U.S. and the blended state rate for the states in which the Company conducts business. As of June 30, 2012, the Company did not have any uncertain tax positions requiring adjustments to its tax liability.

The Company had deferred tax assets for its federal and state tax loss carryforwards at June 30, 2012 recorded in non-current deferred taxes. Deferred tax assets are reduced by a valuation allowance when, in the opinion of management, it is more likely than not that some portion or all of the deferred tax assets will not be realized. As of June 30, 2012, management determined that a valuation allowance was not required for the tax loss carryforwards as they are expected to be fully utilized before expiration.

**10. Earnings Per Share**

Basic earnings per share is computed by dividing income available to common stockholders by the weighted average number of shares outstanding for the periods presented. The calculation of diluted earnings per share includes the impact of potentially dilutive non-vested restricted shares outstanding during the periods presented, unless their effect is anti-dilutive. There are no adjustments made to income available to common stockholders in the calculation of diluted earnings per share.

The following is a calculation of the basic and diluted weighted-average shares outstanding for the three and six months ended June 30, 2012 and 2011:

| | **Three Months Ended June 30,** | | **Six Months Ended June 30,** | |
|---|---|---|---|---|
| | **2012** | **2011** | **2012** | **2011** |
| | **(In thousands)** | | **(In thousands)** | |
| Basic weighted average common shares outstanding | 92,176 | 92,048 | 92,153 | 92,047 |
| Dilution effect of stock awards at end of period | 46 | 103 | 186 | 130 |
| Diluted weighted average common shares outstanding | 92,222 | 92,151 | 92,339 | 92,177 |
| Anti-dilutive stock-based compensation awards | 634 | 272 | 397 | 173 |

**11. Commitments and Contingencies**

*Lease obligations.* The Company s total rental commitments under leases for office space and other property and equipment at June 30, 2012 were $14.7 million.

*Drilling contracts.* As of June 30, 2012, the Company had certain drilling rig contracts with initial terms greater than one year. In the event of early contract termination under these contracts, the Company would be obligated to pay approximately $58.5 million as of June 30, 2012 for the days remaining through the end of the primary terms of the contracts.

*Volume commitment agreements.* As of June 30, 2012, the Company had certain agreements with an aggregate requirement to deliver a minimum quantity of approximately 21.2 MMBbl and 16.5 Bcf from its Williston Basin project areas within a specified timeframe. Future obligations under these agreements were approximately $73.4 million as of June 30, 2012.

*Fracturing services*. As of June 30, 2012, the Company had certain agreements with third party fracturing service companies for an initial term greater than one year. In the event of early contract termination under these agreements, the Company would be obligated to pay approximately $31.4 million as of June 30, 2012 for the months remaining through the end of the primary terms of these agreements.

*Litigation.* The Company is party to various legal and/or regulatory proceedings from time to time arising in the ordinary course of business. The Company believes all such matters are without merit and involve amounts which, if resolved unfavorably, either individually or in the aggregate, will not have a material adverse effect on its financial condition, results of operations or cash flows.

**12. Condensed Consolidating Financial Information**

The 2019 Notes and the 2021 Notes (see Note 7) are guaranteed on a senior unsecured basis by the Guarantors, which are 100% owned by the Company. These guarantees are full and unconditional and joint and several among the Guarantors. Certain of the Company s immaterial wholly owned subsidiaries do not guarantee the Notes ( Non-Guarantor Subsidiaries ).

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The following financial information reflects consolidating financial information of the Company ( Issuer ) and its Guarantors on a combined basis, prepared on the equity basis of accounting. The Non-Guarantor Subsidiaries are immaterial and, therefore, not presented separately. The information is presented in accordance with the requirements of Rule 3-10 under the SEC s Regulation S-X. The financial information may not necessarily be indicative of results of operations, cash flows or financial position had the Guarantors operated as independent entities. The Company has not presented separate financial and narrative information for each of the Guarantors because it believes such financial and narrative information would not provide any additional information that would be material in evaluating the sufficiency of the Guarantors. The consolidating statement of cash flows for the six months ended June 30, 2011 includes a revision in presentation in the Issuer column, which increased cash flows from operating activities by $34.4 million and reduced cash flows from financing activities by the same amount. These revisions are eliminated in consolidation and have no effect on the Guarantors or consolidated financial statements.

**Condensed Consolidating Balance Sheet**

**(In thousands, except share data)**

| | June 30, 2012 | | | |
|---|---|---|---|---|
| | Parent/ Issuer | Combined Guarantor Subsidiaries | Intercompany Eliminations | Consolidated |
| **ASSETS** | | | | |
| Current assets | | | | |
| Cash and cash equivalents | $ 195,660 | $ 43,226 | $ | $ 238,886 |
| Accounts receivable oil and gas revenues | | 79,478 | | 79,478 |
| Accounts receivable joint interest partners | | 66,794 | | 66,794 |
| Accounts receivable from affiliates | 266 | 3,361 | (3,627) | |
| Inventory | | 19,550 | | 19,550 |
| Prepaid expenses | 63 | 611 | | 674 |
| Advances to joint interest partners | | 1,957 | | 1,957 |
| Derivative instruments | | 35,257 | | 35,257 |
| Other current assets | 1 | | | 1 |
| Total current assets | 195,990 | 250,234 | (3,627) | 442,597 |
| Property, plant and equipment | | | | |
| Oil and gas properties (successful efforts method) | | 1,769,570 | | 1,769,570 |
| Other property and equipment | | 41,333 | | 41,333 |
| Less: accumulated depreciation, depletion, amortization and impairment | | (261,529) | | (261,529) |
| Total property, plant and equipment, net | | 1,549,374 | | 1,549,374 |
| Investments in and advances to subsidiaries | 1,313,402 | | (1,313,402) | |
| Derivative instruments | | 18,167 | | 18,167 |
| Deferred income taxes | 24,980 | | (24,980) | |
| Deferred costs and other assets | 22,132 | 4,100 | | 26,232 |
| Total assets | $ 1,556,504 | $ 1,821,875 | $ (1,342,009) | $ 2,036,370 |
| **LIABILITIES AND STOCKHOLDERS EQUITY** | | | | |
| Current liabilities | | | | |
| Accounts payable | $ | $ 1,010 | $ | $ 1,010 |
| Accounts payable from affiliates | 3,361 | 266 | (3,627) | |
| Advances from joint interest partners | | 28,444 | | 28,444 |
| Revenues and production taxes payable | | 56,795 | | 56,795 |
| Accrued liabilities | 7,312 | 230,382 | | 237,694 |
| Accrued interest payable | 16,417 | 10 | | 16,427 |

| | | | | |
|---|---|---|---|---|
| Deferred income taxes | | 11,780 | | 11,780 |
| Other current liabilities | | 2,895 | | 2,895 |
| Total current liabilities | 27,090 | 331,582 | (3,627) | 355,045 |
| Long-term debt | 800,000 | | | 800,000 |
| Asset retirement obligations | | 16,982 | | 16,982 |
| Deferred income taxes | | 158,158 | (24,980) | 133,178 |
| Other liabilities | | 1,751 | | 1,751 |
| Total liabilities | 827,090 | 508,473 | (28,607) | 1,306,956 |
| Stockholders equity | | | | |
| Capital contributions from affiliates | | 1,183,810 | (1,183,810) | |
| Common stock, $0.01 par value; 300,000,000 shares authorized; 93,185,023 issued and 93,122,353 outstanding | 922 | | | 922 |
| Treasury stock, at cost; 62,670 shares | (1,808) | | | (1,808) |
| Additional paid-in-capital | 651,271 | 8,743 | (8,743) | 651,271 |
| Retained earnings | 79,029 | 120,849 | (120,849) | 79,029 |
| Total stockholders equity | 729,414 | 1,313,402 | (1,313,402) | 729,414 |
| Total liabilities and stockholders equity | $ 1,556,504 | $ 1,821,875 | $ (1,342,009) | $ 2,036,370 |

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**Condensed Consolidating Balance Sheet**

**(In thousands, except share data)**

| | December 31, 2011 | | | |
|---|---|---|---|---|
| | Parent/ Issuer | Combined Guarantor Subsidiaries | Intercompany Eliminations | Consolidated |
| **ASSETS** | | | | |
| Current assets | | | | |
| Cash and cash equivalents | $ 443,482 | $ 27,390 | $ | $ 470,872 |
| Short-term investments | 19,994 | | | 19,994 |
| Accounts receivable oil and gas revenues | | 52,164 | | 52,164 |
| Accounts receivable joint interest partners | | 67,268 | | 67,268 |
| Accounts receivable from affiliates | 88 | 1,540 | (1,628) | |
| Inventory | | 3,543 | | 3,543 |
| Prepaid expenses | 309 | 1,831 | | 2,140 |
| Advances to joint interest partners | | 3,935 | | 3,935 |
| Deferred income taxes | | 3,233 | | 3,233 |
| Other current assets | 18 | 473 | | 491 |
| Total current assets | 463,891 | 161,377 | (1,628) | 623,640 |
| Property, plant and equipment | | | | |
| Oil and gas properties (successful efforts method) | | 1,235,357 | | 1,235,357 |
| Other property and equipment | | 20,859 | | 20,859 |
| Less: accumulated depreciation, depletion, amortization and impairment | | (176,261) | | (176,261) |
| Total property, plant and equipment, net | | 1,079,955 | | 1,079,955 |
| Investments in and advances to subsidiaries | 958,880 | | (958,880) | |
| Derivative instruments | | 4,362 | | 4,362 |
| Deferred income taxes | 13,158 | | (13,158) | |
| Deferred costs and other assets | 15,742 | 3,683 | | 19,425 |
| Total assets | $ 1,451,671 | $ 1,249,377 | $ (973,666) | $ 1,727,382 |
| **LIABILITIES AND STOCKHOLDERS EQUITY** | | | | |
| Current liabilities | | | | |
| Accounts payable | $ 23 | $ 12,184 | $ | $ 12,207 |
| Accounts payable from affiliates | 1,540 | 88 | (1,628) | |
| Advances from joint interest partners | | 9,064 | | 9,064 |
| Revenues and production taxes payable | | 19,468 | | 19,468 |
| Accrued liabilities | 103 | 119,589 | | 119,692 |
| Accrued interest payable | 15,767 | 7 | | 15,774 |
| Derivative instruments | | 5,907 | | 5,907 |
| Other current liabilities | | 472 | | 472 |
| Total current liabilities | 17,433 | 166,779 | (1,628) | 182,584 |
| Long-term debt | 800,000 | | | 800,000 |
| Asset retirement obligations | | 13,075 | | 13,075 |
| Derivative instruments | | 3,505 | | 3,505 |
| Deferred income taxes | | 106,141 | (13,158) | 92,983 |

| | | | | |
|---|---|---|---|---|
| Other liabilities | | 997 | | 997 |
| Total liabilities | 817,433 | 290,497 | (14,786) | 1,093,144 |
| Stockholders equity | | | | |
| Capital contributions from affiliates | | 941,575 | (941,575) | |
| Common stock, $0.01 par value; 300,000,000 shares authorized; 92,483,393 issued and 92,460,914 outstanding | 921 | | | 921 |
| Treasury stock, at cost; 22,479 shares | (602) | | | (602) |
| Additional paid-in-capital | 647,374 | 8,743 | (8,743) | 647,374 |
| Retained earnings (deficit) | (13,455) | 8,562 | (8,562) | (13,455) |
| Total stockholders equity | 634,238 | 958,880 | (958,880) | 634,238 |
| Total liabilities and stockholders equity | $ 1,451,671 | $ 1,249,377 | $ (973,666) | $ 1,727,382 |

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**Condensed Consolidating Statement of Operations**

**(In thousands)**

| | Three Months Ended June 30, 2012 | | | |
|---|---|---|---|---|
| | Parent/ Issuer | Combined Guarantor Subsidiaries | Intercompany Eliminations | Consolidated |
| **Revenues** | | | | |
| Oil and gas revenues | $ | $ 145,203 | $ | $ 145,203 |
| Well services revenues | | 3,861 | | 3,861 |
| Total revenues | | 149,064 | | 149,064 |
| **Expenses** | | | | |
| Lease operating expenses | | 12,029 | | 12,029 |
| Well services operating expenses | | 1,207 | | 1,207 |
| Marketing, transportation and gathering expenses | | 1,970 | | 1,970 |
| Production taxes | | 13,720 | | 13,720 |
| Depreciation, depletion and amortization | | 44,213 | | 44,213 |
| Impairment of oil and gas properties | | 2,203 | | 2,203 |
| General and administrative expenses | 2,644 | 10,893 | | 13,537 |
| Total expenses | 2,644 | 86,235 | | 88,879 |
| Operating income (loss) | (2,644) | 62,829 | | 60,185 |
| **Other income (expense)** | | | | |
| Equity in earnings in subsidiaries | 86,024 | | (86,024) | |
| Net gain on derivative instruments | | 74,595 | | 74,595 |
| Interest expense | (13,414) | (660) | | (14,074) |
| Other income | 118 | 658 | | 776 |
| Total other income (expense) | 72,728 | 74,593 | (86,024) | 61,297 |
| Income before income taxes | 70,084 | 137,422 | (86,024) | 121,482 |
| Income tax benefit (expense) | 5,959 | (51,398) | | (45,439) |
| **Net income** | $ 76,043 | $ 86,024 | $ (86,024) | $ 76,043 |

**Condensed Consolidating Statement of Operations**

**(In thousands)**

| | Three Months Ended June 30, 2011 | | | |
|---|---|---|---|---|
| | Parent/ Issuer | Combined Guarantor Subsidiaries | Intercompany Eliminations | Consolidated |
| **Oil and gas revenues** | $ | $ 67,206 | $ | $ 67,206 |
| **Expenses** | | | | |
| Lease operating expenses | | 5,951 | | 5,951 |

| | | | | |
|---|---|---|---|---|
| Marketing, transportation and gathering expenses | | 247 | | 247 |
| Production taxes | | 7,085 | | 7,085 |
| Depreciation, depletion and amortization | | 13,100 | | 13,100 |
| Exploration expenses | | 259 | | 259 |
| Impairment of oil and gas properties | | 1,536 | | 1,536 |
| General and administrative expenses | 1,318 | 5,296 | | 6,614 |
| Total expenses | 1,318 | 33,474 | | 34,792 |
| Operating income (loss) | (1,318) | 33,732 | | 32,414 |
| **Other income (expense)** | | | | |
| Equity in earnings in subsidiaries | 37,557 | | (37,557) | |
| Net gain on derivative instruments | | 27,547 | | 27,547 |
| Interest expense | (6,473) | (288) | | (6,761) |
| Other income | 371 | 8 | | 379 |
| Total other income (expense) | 31,455 | 27,267 | (37,557) | 21,165 |
| Income before income taxes | 30,137 | 60,999 | (37,557) | 53,579 |
| Income tax benefit (expense) | 3,212 | (23,442) | | (20,230) |
| **Net income** | $ 33,349 | $ 37,557 | $ (37,557) | $ 33,349 |

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**Condensed Consolidating Statement of Operations**

**(In thousands)**

| | Six Months Ended June 30, 2012 | | | |
|---|---|---|---|---|
| | Parent/ Issuer | Combined Guarantor Subsidiaries | Intercompany Eliminations | Consolidated |
| **Revenues** | | | | |
| Oil and gas revenues | $ | $ 283,109 | $ | $ 283,109 |
| Well services revenues | | 4,521 | | 4,521 |
| Total revenues | | 287,630 | | 287,630 |
| **Expenses** | | | | |
| Lease operating expenses | | 21,845 | | 21,845 |
| Well services operating expenses | | 1,684 | | 1,684 |
| Marketing, transportation and gathering expenses | | 4,539 | | 4,539 |
| Production taxes | | 26,986 | | 26,986 |
| Depreciation, depletion and amortization | | 83,099 | | 83,099 |
| Exploration expenses | | 2,835 | | 2,835 |
| Impairment of oil and gas properties | | 2,571 | | 2,571 |
| General and administrative expenses | 5,090 | 20,646 | | 25,736 |
| Total expenses | 5,090 | 164,205 | | 169,295 |
| Operating income (loss) | (5,090) | 123,425 | | 118,335 |
| **Other income (expense)** | | | | |
| Equity in earnings in subsidiaries | 112,286 | | (112,286) | |
| Net gain on derivative instruments | | 56,009 | | 56,009 |
| Interest expense | (26,829) | (1,144) | | (27,973) |
| Other income | 295 | 1,079 | | 1,374 |
| Total other income (expense) | 85,752 | 55,944 | (112,286) | 29,410 |
| Income before income taxes | 80,662 | 179,369 | (112,286) | 147,745 |
| Income tax benefit (expense) | 11,822 | (67,083) | | (55,261) |
| **Net income** | $ 92,484 | $ 112,286 | $ (112,286) | $ 92,484 |

**Condensed Consolidating Statement of Operations**

**(In thousands)**

| | Six Months Ended June 30, 2011 | | | |
|---|---|---|---|---|
| | Parent/ Issuer | Combined Guarantor Subsidiaries | Intercompany Eliminations | Consolidated |
| **Oil and gas revenues** | $ | $ 125,950 | $ | $ 125,950 |
| **Expenses** | | | | |

| | | | | |
|---|---|---|---|---|
| Lease operating expenses | | 11,581 | | 11,581 |
| Marketing, transportation and gathering expenses | | 559 | | 559 |
| Production taxes | | 13,168 | | 13,168 |
| Depreciation, depletion and amortization | | 26,912 | | 26,912 |
| Exploration expenses | | 291 | | 291 |
| Impairment of oil and gas properties | | 2,917 | | 2,917 |
| General and administrative expenses | 2,581 | 9,983 | | 12,564 |
| Total expenses | 2,581 | 65,411 | | 67,992 |
| Operating income (loss) | (2,581) | 60,539 | | 57,958 |
| **Other income (expense)** | | | | |
| Equity in earnings in subsidiaries | 34,387 | | (34,387) | |
| Net loss on derivative instruments | | (4,119) | | (4,119) |
| Interest expense | (11,414) | (545) | | (11,959) |
| Other income | 664 | 27 | | 691 |
| Total other income (expense) | 23,637 | (4,637) | (34,387) | (15,387) |
| Income before income taxes | 21,056 | 55,902 | (34,387) | 42,571 |
| Income tax benefit (expense) | 5,446 | (21,515) | | (16,069) |
| **Net income** | $ 26,502 | $ 34,387 | $ (34,387) | $ 26,502 |

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**Condensed Consolidating Statement of Cash Flows**

**(In thousands)**

| | Six Months Ended June 30, 2012 | | | |
|---|---|---|---|---|
| | Parent/ Issuer | Combined Guarantor Subsidiaries | Intercompany Eliminations | Consolidated |
| **Cash flows from operating activities:** | | | | |
| Net income | $ 92,484 | $ 112,286 | $ (112,286) | $ 92,484 |
| Adjustments to reconcile net income to net cash provided by (used in) operating activities: | | | | |
| Equity in earnings of subsidiaries | (112,286) | | 112,286 | |
| Depreciation, depletion and amortization | | 83,099 | | 83,099 |
| Impairment of oil and gas properties | | 2,571 | | 2,571 |
| Deferred income taxes | (11,822) | 66,983 | | 55,161 |
| Derivative instruments | | (56,009) | | (56,009) |
| Stock-based compensation expenses | 3,793 | 105 | | 3,898 |
| Debt discount amortization and other | 960 | 305 | | 1,265 |
| Working capital and other changes: | | | | |
| Change in accounts receivable | (178) | (28,661) | 1,999 | (26,840) |
| Change in inventory | | (21,636) | | (21,636) |
| Change in prepaid expenses | 246 | 1,254 | | 1,500 |
| Change in other current assets | 17 | 473 | | 490 |
| Change in other assets | (7,305) | (60) | | (7,365) |
| Change in accounts payable and accrued liabilities | 9,657 | 32,364 | (1,999) | 40,022 |
| Change in other current liabilities | | 2,470 | | 2,470 |
| Change in other liabilities | | 750 | | 750 |
| Net cash provided by (used in) operating activities | (24,434) | 196,294 | | 171,860 |
| **Cash flows from investing activities:** | | | | |
| Capital expenditures | | (440,781) | | (440,781) |
| Derivative settlements | | (2,465) | | (2,465) |
| Redemptions of short-term investments | 19,994 | | | 19,994 |
| Advances to joint interest partners | | 1,978 | | 1,978 |
| Advances from joint interest partners | | 19,380 | | 19,380 |
| Net cash provided by (used in) investing activities | 19,994 | (421,888) | | (401,894) |
| **Cash flows from financing activities:** | | | | |
| Purchases of treasury stock | (1,206) | | | (1,206) |
| Debt issuance costs | (46) | (700) | | (746) |
| Investment in / capital contributions from affiliates | (242,130) | 242,130 | | |
| Net cash provided by (used in) financing activities | (243,382) | 241,430 | | (1,952) |
| Increase (decrease) in cash and cash equivalents | (247,822) | 15,836 | | (231,986) |
| Cash and cash equivalents at beginning of period | 443,482 | 27,390 | | 470,872 |
| Cash and cash equivalents at end of period | $ 195,660 | $ 43,226 | $ | $ 238,886 |

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**Condensed Consolidating Statement of Cash Flows**

**(In thousands)**

| | Six Months Ended June 30, 2011 Parent/ Issuer | Combined Guarantor Subsidiaries | Intercompany Eliminations | Consolidated |
|---|---|---|---|---|
| **Cash flows from operating activities:** | | | | |
| Net income | $ 26,502 | $ 34,387 | $ (34,387) | $ 26,502 |
| Adjustments to reconcile net income to net cash provided by operating activities: | | | | |
| Equity in earnings of subsidiaries | (34,387) | | 34,387 | |
| Depreciation, depletion and amortization | | 26,912 | | 26,912 |
| Impairment of oil and gas properties | | 2,917 | | 2,917 |
| Deferred income taxes | (5,446) | 21,515 | | 16,069 |
| Derivative instruments | | 4,119 | | 4,119 |
| Stock-based compensation expenses | 1,571 | | | 1,571 |
| Debt discount amortization and other | 489 | 159 | | 648 |
| Working capital and other changes: | | | | |
| Change in accounts receivable | | (20,940) | 995 | (19,945) |
| Change in inventory | | (65) | | (65) |
| Change in prepaid expenses | (382) | 128 | | (254) |
| Change in other current assets | (211) | | | (211) |
| Change in other assets | (100) | (3) | | (103) |
| Change in accounts payable and accrued liabilities | 13,013 | 31,594 | (995) | 43,612 |
| Change in other liabilities | | 323 | | 323 |
| Net cash provided by operating activities | 1,049 | 101,046 | | 102,095 |
| **Cash flows from investing activities:** | | | | |
| Capital expenditures | | (212,267) | | (212,267) |
| Derivative settlements | | (4,652) | | (4,652) |
| Purchases of short-term investments | (164,913) | | | (164,913) |
| Redemptions of short-term investments | 39,974 | | | 39,974 |
| Advances to joint interest partners | | 983 | | 983 |
| Advances from joint interest partners | | 5,851 | | 5,851 |
| Net cash used in investing activities | (124,939) | (210,085) | | (335,024) |
| **Cash flows from financing activities:** | | | | |
| Proceeds from issuance of senior notes | 400,000 | | | 400,000 |
| Purchases of treasury stock | (559) | | | (559) |
| Debt issuance costs | (9,650) | (377) | | (10,027) |
| Investment in / capital contributions from affiliates | (111,078) | 111,078 | | |
| Net cash provided by financing activities | 278,713 | 110,701 | | 389,414 |
| Increase in cash and cash equivalents | 154,823 | 1,662 | | 156,485 |
| Cash and cash equivalents at beginning of period | 119,940 | 23,580 | | 143,520 |
| Cash and cash equivalents at end of period | $ 274,763 | $ 25,242 | $ | $ 300,005 |

**13. Subsequent Events**

The Company has evaluated the period after the balance sheet date, noting no subsequent events or transactions that required recognition or disclosure in the financial statements, other than as noted below.

*Senior unsecured notes.* On July 2, 2012, the Company issued $400 million of 6.875% senior unsecured notes due January 15, 2023 (the 2023 Notes ). Interest is payable on the 2023 Notes semi-annually in arrears on January 15 and July 15 of each year, beginning on January 15, 2013. The 2023 Notes are jointly and severally guaranteed on a senior unsecured basis by all of the Company s existing material subsidiaries. The issuance of the 2023 Notes resulted in net proceeds to the Company of approximately $392 million, which the Company will use to fund its exploration, development and acquisition program and for general corporate purposes. The issuance and sale of the 2023 Notes has been registered under the Securities Act of 1933 pursuant to an automatic shelf Registration Statement on Form S-3 (Registration No. 333-175603), as amended, of the Company, filed with the SEC on July 15, 2011.

*Derivative instruments.* In July 2012, the Company entered into new two-way costless collar options, all of which settle monthly based on the West Texas Intermediate crude oil index price, for a total notional amount of 183,000 barrels in 2012, 1,215,500 barrels in 2013 and 108,500 barrels in 2014. These derivative instruments do not qualify for and were not designated as hedging instruments for accounting purposes.

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**Item 2. Management s Discussion and Analysis of Financial Condition and Results of Operations**

*The following discussion and analysis of our financial condition and results of operations should be read in conjunction with Management s Discussion and Analysis of Financial Condition and Results of Operations contained in our Annual Report on Form 10-K for the year ended December 31, 2011 ( 2011 Annual Report ), as well as the unaudited condensed consolidated financial statements and notes thereto included in this Quarterly Report on Form 10-Q.*

**CAUTIONARY NOTE REGARDING FORWARD-LOOKING STATEMENTS**

This Quarterly Report on Form 10-Q contains forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities and Exchange Act of 1934, as amended. These forward-looking statements are subject to a number of risks and uncertainties, many of which are beyond our control. All statements, other than statements of historical fact included in this Quarterly Report on Form 10-Q, regarding our strategy, future operations, financial position, estimated revenues and losses, projected costs, prospects, plans and objectives of management are forward-looking statements. When used in this Quarterly Report on Form 10-Q, the words could, believe, anticipate, intend, estimate, expect, may, continue, predict, potential, project and similar expressions are int forward-looking statements, although not all forward-looking statements contain such identifying words. In particular, the factors discussed below and detailed under Item 1A. Risk Factors in our 2011 Annual Report and in our Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2012, could affect our actual results and cause our actual results to differ materially from expectations, estimates, or assumptions expressed in, forecasted in, or implied in such forward-looking statements.

Forward-looking statements may include statements about:

- our business strategy;
- estimated future net reserves and present value thereof;
- technology;
- cash flows and liquidity;
- our financial strategy, budget, projections, execution of business plan and operating results;
- oil and natural gas realized prices;
- timing and amount of future production of oil and natural gas;
- availability of drilling, completion and production equipment and materials;
- availability of qualified personnel;
- owning and operating a services company;

the amount, nature and timing of capital expenditures;

availability and terms of capital;

property acquisitions;

costs of exploiting and developing our properties and conducting other operations;

drilling and completion of wells;

infrastructure for salt water disposal;

gathering, transportation and marketing of oil and natural gas, both in the Williston Basin and domestically;

general economic conditions;

operating environment, including inclement weather conditions;

competition in the oil and natural gas industry;

effectiveness of risk management activities;

environmental liabilities;

counterparty credit risk;

governmental regulation and the taxation of the oil and natural gas industry;

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- developments in oil-producing and natural gas-producing countries;
- uncertainty regarding future operating results; and
- plans, objectives, expectations and intentions contained in this report that are not historical.

All forward-looking statements speak only as of the date of this Quarterly Report on Form 10-Q. We disclaim any obligation to update or revise these statements unless required by securities law, and you should not place undue reliance on these forward-looking statements. Although we believe that our plans, intentions and expectations reflected in or suggested by the forward-looking statements we make in this Quarterly Report on Form 10-Q are reasonable, we can give no assurance that these plans, intentions or expectations will be achieved. Some of the key factors which could cause actual results to vary from our expectations include changes in oil and natural gas prices, the timing of planned capital expenditures, availability of acquisitions, uncertainties in estimating proved reserves and forecasting production results, operational factors affecting the commencement or maintenance of producing wells, the condition of the capital markets generally, as well as our ability to access them, the proximity to and capacity of transportation facilities, and uncertainties regarding environmental regulations or litigation and other legal or regulatory developments affecting our business, as well as those factors discussed below and elsewhere in this Quarterly Report on Form 10-Q, all of which are difficult to predict. In light of these risks, uncertainties and assumptions, the forward-looking events discussed may not occur. These cautionary statements qualify all forward-looking statements attributable to us or persons acting on our behalf.

**Overview**

We are an independent exploration and production company focused on the acquisition and development of unconventional oil and natural gas resources primarily in the Montana and North Dakota regions of the Williston Basin. Since our inception, we have acquired properties that provide current production and significant upside potential through further development. Our drilling activity is primarily directed toward projects that we believe can provide us with repeatable successes in the Bakken and Three Forks formations. We also operate businesses that are complementary to our primary development and production activities, including a marketing business, Oasis Petroleum Marketing LLC ( OPM ), and a well services business, Oasis Well Services LLC ( OWS ). The revenues and expenses related to work performed by OPM and OWS for Oasis Petroleum North America LLC s working interests are eliminated in consolidation and, therefore, do not directly contribute to our consolidated results of operations.

Our use of capital for acquisitions and development allows us to direct our capital resources to what we believe to be the most attractive opportunities as market conditions evolve. We have historically acquired properties that we believe will meet or exceed our rate of return criteria. For acquisitions of properties with additional development, exploitation and exploration potential, we have focused on acquiring properties that we expect to operate so that we can control the timing and implementation of capital spending. In some instances, we have acquired non-operated property interests at what we believe to be attractive rates of return either because they provided a foothold in a new area of interest or complemented our existing operations. We intend to continue to acquire both operated and non-operated properties to the extent we believe they meet our return objectives. In addition, the acquisition of non-operated properties in new areas provides us with geophysical and geologic data that may lead to further acquisitions in the same area, whether on an operated or non-operated basis.

Due to the geographic concentration of our oil and natural gas properties in the Williston Basin, we believe the primary sources of opportunities, challenges and risks related to our business for both the short and long-term are:

- Commodity prices for oil and natural gas;
- Transportation capacity;
- Availability and cost of services; and
- Availability of qualified personnel.

Our revenue, profitability and future growth rate depend substantially on factors beyond our control, such as economic, political and regulatory developments as well as competition from other sources of energy. Oil and natural gas prices historically have been volatile and may fluctuate widely in the future. Sustained periods of low prices for oil or natural gas could materially and adversely affect our financial position, our results of operations, the quantities of oil and natural gas reserves that we can economically produce and our access to capital.

Prices for oil and natural gas can fluctuate widely in response to relatively minor changes in the global and regional supply of and demand for oil and natural gas, as well as market uncertainty, economic conditions and a variety of additional factors. Since the inception of our oil and natural gas activities, commodity prices have experienced significant fluctuations. We enter into crude oil sales contracts with purchasers who have access to crude oil transportation capacity, utilize derivative financial instruments to manage our commodity price risk, and enter into physical delivery contracts to manage our price differentials. In an effort to improve price realizations from the sale of our oil and natural gas, we manage our commodities marketing activities in-house, which enables us to market and sell our oil and natural gas to a broader array of potential purchasers. Due to the availability of other markets and pipeline connections, we do not believe that the loss of any single oil or natural gas customer would have a material adverse effect on our results of operations or cash flows. Additionally, during the first and second quarters of 2012, we began to actively increase the number of operated wells that we have connected to a third-party oil gathering system in our West Williston project area. At the end of June 2012, the Company had 94 operated wells connected, up from only three operated wells that were connected at the beginning of 2012. We currently flow approximately 60% of our gross operated oil production on the third-party oil gathering system.

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Changes in commodity prices may also significantly affect the economic viability of drilling projects as well as the economic valuation and economic recovery of oil and gas reserves. Oil prices have increased significantly since 2009. As a result of higher commodity prices and continued successes in the application of completion technologies in the Bakken formation, there were more than 225 active drilling rigs in the Williston Basin at June 30, 2012. Although additional Williston Basin transportation takeaway capacity was added in recent months, production also increased due to the elevated drilling activity. The increased production coupled with the refinery and transportation constraints caused price differentials in the first and second quarters of 2012 to be at and above the high end of the historical average range of approximately 10% to 15% of the price quoted for NYMEX West Texas Intermediate ( WTI ) crude oil.

Our large concentrated acreage position potentially provides us with a multi-year inventory of drilling projects and requires some forward planning visibility for obtaining services. Our ability to develop and hold our existing undeveloped leasehold acreage is primarily dependent upon having access to drilling rigs and completion services. The utilization of existing drilling rigs and of existing completion service equipment in the Williston Basin is at an all-time high. This has resulted in drilling rigs, completion equipment and crews being imported from Canada and other parts of the United States. To ensure access to drilling rigs, we have entered into fixed-term drilling rig contracts for periods of up to three years and currently have ten drilling rigs under contract. In order to ensure the availability of completion services and the timely fracture stimulation of newly drilled wells, we formed OWS in June 2011 to provide well services on our operated wells, in addition to entering into fracturing service contracts with third party companies.

***Second Quarter 2012 Highlights:***

- We completed and placed on production 26 gross (20.3 net) operated wells in the Williston Basin during the three months ended June 30, 2012;

- We had 30 gross (24.1 net) operated wells awaiting completion and 9 gross (7.4 net) operated wells in the process of being drilled in the Bakken and Three Forks formations at June 30, 2012;

- Average daily production was 20,353 Boe per day during the three months ended June 30, 2012;

- Net gas production increased to 11.2 MMcfpd during the three months ended June 30, 2012 due to connecting additional wells in the Williston Basin to third-party infrastructure;

- Exploration and production ( E&P ) capital expenditures were $263.2 million, consisting primarily of $243.4 million in drilling expenditures during the three months ended June 30, 2012;

- At June 30, 2012, we had $238.9 million of cash and cash equivalents and had no outstanding debt or outstanding letters of credit under our revolving credit facility; and

- On June 27, 2012, we priced an offering of $400 million of 6.875% senior unsecured notes due January 15, 2023. The issuance closed on July 2, 2012, resulting in net proceeds to us of approximately $392 million.

**Results of Operations**

***Revenues***

Our revenues are derived from the sale of oil and natural gas production and do not include the effects of derivative instruments. Our revenues may vary significantly from period to period as a result of changes in volumes of production sold or changes in commodity prices.

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The following table summarizes our revenues and production data for the periods indicated.

| | Three Months Ended June 30, | | | Six Months Ended June 30, | | |
|---|---|---|---|---|---|---|
| | 2012 | 2011 | Change | 2012 | 2011 | Change |
| **Operating results (in thousands):** | | | | | | |
| Revenues | | | | | | |
| Oil | $ 138,559 | $ 65,400 | $ 73,159 | $ 269,935 | $ 122,572 | $ 147,363 |
| Natural gas | 6,644 | 1,806 | 4,838 | 13,174 | 3,378 | 9,796 |
| Well services | 3,861 | | 3,861 | 4,521 | | 4,521 |
| Total oil and gas revenues | 149,064 | 67,206 | 81,858 | 287,630 | 125,950 | 161,680 |
| **Production data:** | | | | | | |
| Oil (MBbls) | 1,682 | 685 | 997 | 3,156 | 1,379 | 1,777 |
| Natural gas (MMcf) | 1,019 | 200 | 819 | 1,803 | 402 | 1,401 |
| Oil equivalents (MBoe) | 1,852 | 718 | 1,134 | 3,457 | 1,446 | 2,011 |
| Average daily production (Boe/d) | 20,353 | 7,893 | 12,460 | 18,993 | 7,991 | 11,002 |
| **Average sales prices:** | | | | | | |
| Oil, without realized derivatives (per Bbl) (1) | $ 82.36 | $ 95.48 | $ (13.12) | $ 85.04 | $ 88.86 | $ (3.82) |
| Oil, with realized derivatives (per Bbl) (1) (2) | 81.67 | 89.43 | (7.76) | 84.26 | 85.49 | (1.23) |
| Natural gas (per Mcf) (3) | 6.52 | 9.05 | (2.53) | 7.30 | 8.41 | (1.11) |

(1) For the six months ended June 30, 2012, average sales prices for oil are calculated using total oil revenues, excluding bulk purchase sales of $1.5 million, divided by oil production.

(2) Realized prices include realized gains or losses on cash settlements for commodity derivatives, which do not qualify for and were not designated as hedging instruments for accounting purposes.

(3) Natural gas prices include the value for natural gas and natural gas liquids.

***Three months ended June 30, 2012 as compared to three months ended June 30, 2011***

*Total revenues*. Our total revenues increased $81.9 million, or 122%, to $149.1 million during the three months ended June 30, 2012 as compared to the three months ended June 30, 2011. Our primary revenues are a function of oil and natural gas production volumes sold and average sales prices received for those volumes. Average daily production sold increased by 12,460 Boe per day, or 158%, to 20,353 Boe per day during the three months ended June 30, 2012 as compared to the three months ended June 30, 2011. The increase in average daily production sold was primarily a result of our well completions during the last two quarters of 2011 and the first two quarters of 2012. Well completions in our West Williston, East Nesson and Sanish project areas increased average daily production by approximately 9,266 Boe per day, 2,584 Boe per day and 712 Boe per day, respectively, during the second quarter of 2012 as compared to the second quarter of 2011. Average oil sales prices, without realized derivatives, decreased by $13.12/Bbl, or 14%, to an average of $82.36/Bbl for the three months ended June 30, 2012 as compared to the three months ended June 30, 2011. The higher production amounts sold increased revenues by $87.5 million, while lower oil and natural gas sales prices decreased revenues by $9.5 million during the three months ended June 30, 2012. The remaining $3.9 million increase in total revenues was attributable to well services revenues during the three months ended June 30, 2012. There were no well services revenues during the second quarter of 2011 because OWS did not commence fracturing activity until the first quarter of 2012.

***Six months ended June 30, 2012 as compared to six months ended June 30, 2011***

*Total revenues*. Our total revenues increased $161.7 million, or 128%, to $287.6 million during the six months ended June 30, 2012 as compared to the six months ended June 30, 2011. Our primary revenues are a function of oil and natural gas production volumes sold and average sales prices received for those volumes. Average daily production sold increased by 11,002 Boe per day, or 138%, to 18,993 Boe per day during the six months ended June 30, 2012 as compared to the six months ended June 30, 2011. The increase in average daily production sold was primarily a result of our well completions during the last two quarters of 2011 and the first two quarters of 2012. Well completions in our West Williston, East Nesson and Sanish project areas increased average daily production by approximately 8,542 Boe per day, 2,043 Boe per day and 451 Boe per day, respectively, during the six months ended June 30, 2012 as compared to the six months ended June 30, 2011. Average oil sales prices, without realized derivatives, decreased by $3.82/Bbl, or 4%, to an average of $85.04/Bbl for the six months ended June 30, 2012 as compared to the six months ended June 30, 2011. The higher production amounts sold increased revenues by $161.3 million, while lower oil and natural gas sales prices decreased revenues by $5.7 million during the six months ended June 30, 2012. Well services revenues were $4.5 million for the six months ended June 30, 2012 compared to no well services revenues during the six months ended June 30, 2011 because OWS did not commence fracturing activity until the first quarter of 2012. The remaining $1.5 million increase in total revenues was attributable to oil bulk purchase revenues related to marketing activities included in oil and gas revenues during the six months ended June 30, 2012.

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***Expenses***

The following table summarizes our operating expenses for the periods indicated.

| | Three Months Ended June 30, | | | Six Months Ended June 30, | | |
|---|---|---|---|---|---|---|
| | 2012 | 2011 | $ Change | 2012 | 2011 | $ Change |
| | (In thousands, except per Boe of production) | | | | | |
| **Expenses:** | | | | | | |
| Lease operating expenses | $ 12,029 | $ 5,951 | $ 6,078 | $ 21,845 | $ 11,581 | $ 10,264 |
| Well services operating expenses | 1,207 | | 1,207 | 1,684 | | 1,684 |
| Marketing, transportation and gathering expenses | 1,970 | 247 | 1,723 | 4,539 | 559 | 3,980 |
| Production taxes | 13,720 | 7,085 | 6,635 | 26,986 | 13,168 | 13,818 |
| Depreciation, depletion and amortization | 44,213 | 13,100 | 31,113 | 83,099 | 26,912 | 56,187 |
| Exploration expenses | | 259 | (259) | 2,835 | 291 | 2,544 |
| Impairment of oil and gas properties | 2,203 | 1,536 | 667 | 2,571 | 2,917 | (346) |
| General and administrative expenses | 13,537 | 6,614 | 6,923 | 25,736 | 12,564 | 13,172 |
| Total expenses | $ 88,879 | $ 34,792 | $ 54,087 | $ 169,295 | $ 67,992 | $ 101,303 |
| Operating income (loss) | 60,185 | 32,414 | 27,771 | 118,335 | 57,958 | 60,377 |
| **Other income (expense):** | | | | | | |
| Net gain (loss) on derivative instruments | 74,595 | 27,547 | 47,048 | 56,009 | (4,119) | 60,128 |
| Interest expense | (14,074) | (6,761) | (7,313) | (27,973) | (11,959) | (16,014) |
| Other income | 776 | 379 | 397 | 1,374 | 691 | 683 |
| Total other income (expense) | 61,297 | 21,165 | 40,132 | 29,410 | (15,387) | 44,797 |
| **Income before income taxes** | 121,482 | 53,579 | 67,903 | 147,745 | 42,571 | 105,174 |
| Income tax expense | 45,439 | 20,230 | 25,209 | 55,261 | 16,069 | 39,192 |
| **Net income (loss)** | $ 76,043 | $ 33,349 | $ 42,694 | $ 92,484 | $ 26,502 | $ 65,982 |
| **Cost and expense (per Boe of production):** | | | | | | |
| Lease operating expenses (1) | $ 6.49 | $ 8.29 | $ (1.80) | $ 6.32 | $ 8.00 | $ (1.68) |
| Marketing, transportation and gathering expenses | 1.06 | 0.34 | 0.72 | 1.31 | 0.39 | 0.92 |
| Production taxes | 7.41 | 9.86 | (2.45) | 7.81 | 9.10 | (1.29) |
| Depreciation, depletion and amortization | 23.87 | 18.24 | 5.63 | 24.04 | 18.61 | 5.43 |
| General and administrative expenses (2) | 7.31 | 9.21 | (1.90) | 7.45 | 8.69 | (1.24) |

(1) For the three and six months ended June 30, 2011, lease operating expenses excludes marketing, transportation and gathering expenses to conform such amount to current year classifications.

(2) Includes $1.1 million and $2.7 million of expenses related to OWS for the three and six months ended June 30, 2012, respectively. Excluding OWS, E&P only G&A would be $6.71 and $6.66 per Boe for the three and six months ended June 30, 2012, respectively.

***Three months ended June 30, 2012 compared to three months ended June 30, 2011***

*Lease operating expenses*. Lease operating expenses increased $6.1 million to $12.0 million for the three months ended June 30, 2012 compared to the three months ended June 30, 2011. This increase was due to an increased number of producing wells and increased workover expenses period over period. The unit operating costs decreased from $8.29 per Boe for the three months ended June 30, 2011 to $6.49 per Boe for the three months ended June 30, 2012, as a result of operational efficiency and lower salt water disposal ( SWD ) costs.

We have $74 million in our 2012 capital budget primarily allocated to building SWD infrastructure, which is currently being deployed in our key operating areas. This infrastructure is expected to reduce our dependence on trucks for water hauling and simplify operational logistics. As of June 30, 2012, we had approximately 30% of operated water production flowing through our operated pipeline system. We expect to have approximately 80% of operated water production flowing through the pipeline system by year-end 2012. Additionally, we currently dispose of approximately 60% of our operated water production at our operated disposal wells. This continued expansion of our SWD systems is expected to reduce lease operating expenses throughout the remainder of 2012.

*Well services operating expenses*. The $1.2 million in well services operating expenses represents non-affiliated fracturing service costs incurred by OWS for fracturing jobs completed in the second quarter of 2012. There were no well services operating expenses during the second quarter of 2011 because OWS did not commence fracturing activity until the first quarter of 2012.

*Marketing, transportation and gathering expenses*. This line item includes all of our marketing, transportation and gathering for our oil production as well as bulk oil purchase costs. The $1.7 million increase quarter over quarter, or $0.72 increase per Boe, is mainly attributable to increased oil transportation costs related to OPM, which did not commence operations until the third quarter of 2011.

*Production taxes*. Our production taxes for the three months ended June 30, 2012 and 2011 were 9.5% and 10.5%, respectively, as a percentage of oil and natural gas sales. The second quarter 2012 production tax rate was lower than the second quarter 2011 production tax rate primarily due to certain new wells in Montana that are subject to lower incentivized production tax rates.

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*Depreciation, depletion and amortization (DD&A).* DD&A expense increased $31.1 million to $44.2 million for the three months ended June 30, 2012 compared to the three months ended June 30, 2011. This increase in DD&A expense for the three months ended June 30, 2012 was primarily a result of our production increases from our well completions during the last two quarters of 2011 and the first two quarters of 2012. The DD&A rate for the three months ended June 30, 2012 was $23.87 per Boe compared to $18.24 per Boe for the three months ended June 30, 2011. The higher DD&A rate was due to a greater increase in well costs over an increase in reserves.

*Impairment of oil and gas properties*. During the three months ended June 30, 2012 and 2011, we recorded non-cash impairment charges of $2.2 million and $1.5 million, respectively, for unproved property leases that expired during the period or have been forecasted to expire under our current drilling plans. No impairment charges of proved oil and gas properties were recorded for the three months ended June 30, 2012 or 2011.

*General and administrative expenses*. Our general and administrative ( G&A ) expenses increased $6.9 million for the three months ended June 30, 2012 from $6.6 million for the three months ended June 30, 2011. Of this increase, approximately $6.0 million related to employee compensation expenses due to our organizational growth, including the addition of OWS, and $1.3 million was due to additional amortization of our restricted stock awards during the three months ended June 30, 2012. As of June 30, 2012, we had 223 full-time employees compared to 88 full-time employees as of June 30, 2011. Excluding G&A expenses related to OWS of $1.1 million, G&A related to E&P on a per Boe basis would have been $6.71 in the second quarter of 2012.

*Derivative instruments*. As a result of our derivative activities, we incurred cash settlement net losses of $1.2 million and $4.1 million for the three months ended June 30, 2012 and 2011, respectively. In addition, as a result of forward oil price changes, we recognized a $75.8 million and a $31.7 million non-cash unrealized mark-to-market net derivative gain during the three months ended June 30, 2012 and 2011, respectively.

*Interest expense*. Interest expense increased $7.3 million to $14.1 million for the three months ended June 30, 2012 compared to the three months ended June 30, 2011. The increase was primarily the result of interest expense incurred on our senior unsecured notes issued in November 2011 at an interest rate of 6.5%. There were no borrowings under our revolving credit facility during the three months ended June 30, 2012 and 2011, respectively.

*Income taxes.* Income tax expense for the three months ended June 30, 2012 and 2011 was recorded at 37.4% and 37.8% of pre-tax net income, respectively. Our effective tax rate is expected to continue to closely approximate the statutory rate applicable to the U.S. and the blended state rate of the states in which we conduct business.

***Six months ended June 30, 2012 compared to six months ended June 30, 2011***

*Lease operating expenses*. Lease operating expenses increased $10.3 million to $21.8 million for the six months ended June 30, 2012 compared to the six months ended June 30, 2011. This increase was due to an increased number of producing wells and increased workover expenses period over period. The unit operating costs decreased from $8.00 per Boe for the six months ended June 30, 2011 to $6.32 per Boe for the six months ended June 30, 2012, as a result of operational efficiency and lower SWD costs.

*Well services operating expenses*. The $1.7 million in well services operating expenses represents non-affiliated fracturing service costs incurred by OWS for fracturing jobs completed in 2012. There were no well services operating expenses in 2011 because OWS did not commence fracturing activity until the first quarter of 2012.

*Marketing, transportation and gathering expenses*. This line item includes all of our marketing, transportation and gathering for our oil production as well as bulk oil purchase costs. The $4.0 million increase period over period, or $0.92 increase per Boe, is mainly attributable to increased oil transportation costs related to OPM, which did not commence operations until the third quarter of 2011.

*Production taxes*. Our production taxes for the six months ended June 30, 2012 and 2011 were 9.6% and 10.5%, respectively, as a percentage of oil and natural gas sales. The production tax rate for the six months ended June 30, 2012 was lower than the production tax rate for the six months ended June 30, 2011 primarily due to certain new wells in Montana that are subject to lower incentivized production tax rates.

*Depreciation, depletion and amortization (DD&A).* DD&A expense increased $56.2 million to $83.1 million for the six months ended June 30, 2012 compared to the six months ended June 30, 2011. This increase in DD&A expense for the six months ended June 30, 2012 was primarily a result of our production increases from our well completions during the last two quarters of 2011 and the first two quarters of 2012. The DD&A rate for the six months ended June 30, 2012 was $24.04 per Boe compared to $18.61 per Boe for the six months ended June 30, 2011. The higher DD&A rate was due to a greater increase in well costs over an increase in reserves.

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*Exploration expenses*. The $2.5 million increase in exploration expenses to $2.8 million for the six months ended June 30, 2012 is primarily due to geological and geophysical costs for the purchase of 3D seismic data.

*Impairment of oil and gas properties*. During the six months ended June 30, 2012 and 2011, we recorded non-cash impairment charges of $2.6 million and $2.9 million, respectively, for unproved property leases that expired during the period or have been forecasted to expire under our current drilling plans. No impairment charges of proved oil and gas properties were recorded for the three months ended June 30, 2012 or 2011.

*General and administrative expenses*. Our general and administrative ( G&A ) expenses increased $13.2 million for the six months ended June 30, 2012 from $12.6 million for the six months ended June 30, 2011. Of this increase, approximately $9.9 million related to employee compensation expenses due to our organizational growth, including the addition of OWS, and $2.3 million was due to additional amortization of our restricted stock awards during the six months ended June 30, 2012. As of June 30, 2012, we had 223 full-time employees compared to 88 full-time employees as of June 30, 2011. Excluding G&A expenses related to OWS of $2.7 million, G&A related to E&P on a per Boe basis would have been $6.66 for the six months ended June 30, 2012.

*Derivative instruments*. As a result of our derivative activities, we incurred cash settlement net losses of $2.5 million and $4.7 million for the six months ended June 30, 2012 and 2011, respectively. In addition, as a result of forward oil price changes, we recognized a $58.5 million and a $0.5 million non-cash unrealized mark-to-market net derivative gain during the six months ended June 30, 2012 and 2011, respectively.

*Interest expense*. Interest expense increased $16.0 million to $28.0 million for the six months ended June 30, 2012 compared to the six months ended June 30, 2011. The increase was primarily the result of interest expense incurred on our senior unsecured notes issued in February and November 2011 at interest rates of 7.25% and 6.5%, respectively. There were no borrowings under our revolving credit facility during the six months ended June 30, 2012 and 2011, respectively.

*Income taxes.* Income tax expense for the six months ended June 30, 2012 and 2011 was recorded at 37.4% and 37.8% of pre-tax net income, respectively. Our effective tax rate is expected to continue to closely approximate the statutory rate applicable to the U.S. and the blended state rate of the states in which we conduct business.

**Liquidity and Capital Resources**

Our primary sources of liquidity as of the date of this report have been proceeds from our issuances of senior unsecured notes, proceeds from our IPO in June 2010, cash flows from operations and historically, borrowings under our revolving credit facility and capital contributions from private investors. Our primary use of capital has been for the acquisition, development and exploration of oil and natural gas properties. We continually monitor potential capital sources, including equity and debt financings, in order to meet our planned capital expenditures and liquidity requirements. Our future success in growing proved reserves and production will be highly dependent on our ability to access outside sources of capital.

Our cash flows for the six months ended June 30, 2012 and 2011 are presented below:

| | Six Months Ended June 30, | |
|---|---|---|
| | 2012 | 2011 |
| | (In thousands) | |
| Net cash provided by operating activities | $ 171,860 | $ 102,095 |
| Net cash used in investing activities | (401,894) | (335,024) |
| Net cash (used in) provided by financing activities | (1,952) | 389,414 |
| (Decrease) increase in cash and cash equivalents | $ (231,986) | $ 156,485 |

***Cash flows provided by operating activities***

Our cash flows depend on many factors, including the price of oil and natural gas and the success of our development and exploration activities as well as future acquisitions. We actively manage our exposure to commodity price fluctuations by executing derivative transactions to mitigate the change in oil prices on a portion of our production, thereby mitigating our exposure to oil price declines, but these transactions may also limit our cash flow in periods of rising oil prices.

Net cash provided by operating activities was $171.9 million and $102.1 million for the six months ended June 30, 2012 and 2011, respectively. The increase in cash flows provided by operating activities for the period ended June 30, 2012 as compared to 2011 was primarily the result of an increase in oil and natural gas production of 138%. In addition, at June 30, 2012, we had a working capital surplus of $87.6 million. This surplus was primarily attributable to our cash and cash equivalents balance as a result of the net proceeds from the issuance of our senior unsecured notes in 2011.

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***Cash flows used in investing activities***

Net cash used in investing activities was $401.9 million and $335.0 million during the six months ended June 30, 2012 and 2011, respectively. The increase in cash used in investing activities for the six months ended June 30, 2012 compared to 2011 of $66.9 million was mainly attributable to increased levels of capital expenditures for drilling and development costs.

Our capital expenditures for drilling, development and acquisition costs are summarized in the following table:

| | Six Months Ended June 30, 2012 (In thousands) |
|---|---|
| **Project Area:** | |
| West Williston | $ 391,975 |
| East Nesson | 106,617 |
| Sanish | 31,575 |
| Total E&P capital expenditures | 530,167 |
| Non-E&P capital expenditures (1) | 25,368 |
| Total capital expenditures (2) | $ 555,535 |

(1) Non-E&P capital expenditures include such items as equipment for OWS, district tools, administrative capital and capitalized interest.

(2) Capital expenditures reflected in the table above differ from the amounts shown in the statement of cash flows in our condensed consolidated financial statements because amounts reflected in the table above include accrued liabilities for capital expenditures, while the amounts presented in the statement of cash flows are presented on a cash basis.

On July 26, 2012, our Board of Directors increased our total 2012 capital expenditure budget from $884 million to $1,062 million, which now consists of:

$912 million of development capital for operated and non-operated wells (including expected savings from services provided by OWS);

$74 million for constructing infrastructure to support production in our core project areas, primarily related to SWD systems that will lower lease operating expenses;

$30 million for maintaining and expanding our leasehold position;

$6 million for micro-seismic work, purchase of seismic data and other test work;

$17 million for OWS, including $12 million for equipment budgeted and ordered in 2011 that arrived in the first quarter of 2012; and

$23 million for other non-E&P capital, including items such as district tools, administrative capital and capitalized interest.

The 2012 capital expenditure budget does not include approximately $30 million of capital that was related to 2011 activity that was included in the first quarter of 2012 actual capital expenditures. While we have budgeted $1,062 million for these purposes, the ultimate amount of capital we will expend may fluctuate materially based on market conditions and the success of our drilling and operations results as the year progresses. We believe that cash on hand, cash flows from operating activities and availability under our revolving credit facility should be more than sufficient to fund our 2012 capital expenditure budget. However, because the operated wells funded by our 2012 drilling plan represent only a small percentage of our gross identified drilling locations, we will be required to generate or raise multiples of this amount of capital to develop our entire inventory of identified drilling locations should we elect to do so.

Our capital budget may be adjusted as business conditions warrant. The amount, timing and allocation of capital expenditures is largely discretionary and within our control. If oil and natural gas prices decline or costs increase significantly, we could defer a significant portion of our budgeted capital expenditures until later periods to prioritize capital projects that we believe have the highest expected returns and potential to generate near-term cash flows. We routinely monitor and adjust our capital expenditures in response to changes in prices, availability of financing, drilling and acquisition costs, industry conditions, the timing of regulatory approvals, the availability of rigs, success or lack of success in drilling activities, contractual obligations, internally generated cash flows and other factors both within and outside our control.

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***Cash flows used in or provided by financing activities***

Net cash used in financing activities was $2.0 million for the six months ended June 30, 2012 compared to $389.4 million net cash provided by financing activities for the six months ended June 30, 2011. For the six months ended June 30, 2012, cash used in financing activities was primarily due to the purchases of treasury stock for shares withheld by the Company equivalent to the payroll tax withholding obligations due from employees upon the vesting of restricted stock awards combined with deferred financing costs related to the semi-annual redetermination of our borrowing base under our senior secured revolving line of credit. For the six months ended June 30, 2011, cash sourced through financing activities was primarily provided by the net proceeds from the issuance of our senior unsecured notes in February 2011.

*Senior unsecured notes.* On February 2, 2011, we issued $400 million of 7.25% senior unsecured notes due February 1, 2019 (the 2019 Notes ). Interest is payable on the 2019 Notes semi-annually in arrears on each February 1 and August 1, commencing August 1, 2011. The 2019 Notes are guaranteed on a senior unsecured basis by our material subsidiaries. The issuance of these 2019 Notes resulted in net proceeds to us of approximately $390 million, which we are using to fund our exploration, development and acquisition program and for general corporate purposes.

At any time prior to February 1, 2014, we may redeem up to 35% of the 2019 Notes at a redemption price of 107.25% of the principal amount, plus accrued and unpaid interest to the redemption date, with the proceeds of certain equity offerings as long as the redemption occurs within 180 days of completing such equity offering and at least 65% of the aggregate principal amount of the 2019 Notes remains outstanding after such redemption. Prior to February 1, 2015, we may redeem some or all of the 2019 Notes for cash at a redemption price equal to 100% of their principal amount plus an applicable make-whole premium and accrued and unpaid interest to the redemption date. On and after February 1, 2015, we may redeem some or all of the 2019 Notes at redemption prices (expressed as percentages of the principal amount) equal to 103.625% for the twelve-month period beginning on February 1, 2015, 101.813% for the twelve-month period beginning February 1, 2016 and 100.00% beginning on February 1, 2017, plus accrued and unpaid interest to the redemption date.

On November 10, 2011, we issued $400 million of 6.5% senior unsecured notes due November 1, 2021 (the 2021 Notes ). Interest is payable on the 2021 Notes semi-annually in arrears on each May 1 and November 1, commencing May 1, 2012. The 2021 Notes are guaranteed on a senior unsecured basis by our material subsidiaries. The issuance of these 2021 Notes resulted in net proceeds to us of approximately $393 million, which we are using to fund our exploration, development and acquisition program and for general corporate purposes.

At any time prior to November 1, 2014, we may redeem up to 35% of the 2021 Notes at a redemption price of 106.5% of the principal amount, plus accrued and unpaid interest to the redemption date, with the proceeds of certain equity offerings as long as the redemption occurs within 180 days of completing such equity offering and at least 65% of the aggregate principal amount of the 2021 Notes remains outstanding after such redemption. Prior to November 1, 2016, we may redeem some or all of the 2021 Notes for cash at a redemption price equal to 100% of their principal amount plus an applicable make-whole premium and accrued and unpaid interest to the redemption date. On and after November 1, 2016, we may redeem some or all of the 2021 Notes at redemption prices (expressed as percentages of principal amount) equal to 103.25% for the twelve-month period beginning on November 1, 2016, 102.167% for the twelve-month period beginning on November 1, 2017, 101.083% for the twelve-month period beginning on November 1, 2018 and 100.00% beginning on November 1, 2019, plus accrued and unpaid interest to the redemption date. If a change in control occurs at any time on or prior to January 1, 2013, we may redeem all, but not less than all, of the 2021 Notes, at a redemption price equal to 110% of the principal amount plus accrued and unpaid interest to the redemption date.

On July 2, 2012, we issued $400 million of 6.875% senior unsecured notes due January 15, 2023 (the 2023 Notes ). Interest is payable on the 2023 Notes semi-annually in arrears on each January 15 and July 15, commencing January 15, 2013. The 2021 Notes are guaranteed on a senior unsecured basis by our material subsidiaries. The issuance of these 2023 Notes resulted in net proceeds to us of approximately $392.4 million, which we are using to fund our exploration, development and acquisition program and for general corporate purposes.

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At any time prior to July 15, 2015, we may redeem up to 35% of the 2023 Notes at a redemption price of 106.875% of the principal amount, plus accrued and unpaid interest to the redemption date, with the proceeds of certain equity offerings as long as the redemption occurs within 180 days of completing such equity offering and at least 65% of the aggregate principal amount of the 2023 Notes remains outstanding after such redemption. Prior to July 15, 2017, we may redeem some or all of the 2023 Notes for cash at a redemption price equal to 100% of their principal amount plus an applicable make-whole premium and accrued and unpaid interest to the redemption date. On and after July 15, 2017, we may redeem some or all of the 2023 Notes at redemption prices (expressed as percentages of principal amount) equal to 103.438% for the twelve-month period beginning on July 15, 2017, 102.292% for the twelve-month period beginning on July 15, 2018, 101.146% for the twelve-month period beginning on July 15, 2019 and 100.00% beginning on July 15, 2020, plus accrued and unpaid interest to the redemption date. If a change in control occurs at any time on or prior to July 15, 2013, we may redeem all, but not less than all, of the 2023 Notes, at a redemption price equal to 110% of the principal amount plus accrued and unpaid interest to the redemption date.

The indentures governing our 2019 Notes, 2021 Notes and 2023 Notes restrict our ability and the ability of certain of our subsidiaries to: (i) incur additional debt or enter into sale and leaseback transactions; (ii) pay distributions on, redeem or repurchase equity interests; (iii) make certain investments; (iv) incur liens; (v) enter into transactions with affiliates; (vi) merge or consolidate with another company; and (vii) transfer and sell assets. These covenants are subject to a number of important exceptions and qualifications. If at any time when our 2019 Notes, 2021 Notes or 2023 Notes are rated investment grade by both Moody s Investors Service, Inc. and Standard & Poor s Ratings Services and no default (as defined in the indentures) has occurred and is continuing, many of such covenants will terminate and we will cease to be subject to such covenants.

*Senior secured revolving line of credit*. On April 3, 2012, we entered into a sixth amendment to our revolving credit facility. In connection with this amendment, the semi-annual redetermination of our borrowing base was completed on April 3, 2012, which resulted in an increase to the borrowing base of our revolving credit facility from $350 million to $500 million. Additionally, two new lenders were added to the bank group. Borrowings under our revolving credit facility are collateralized by perfected first priority liens and security interests on substantially all of our assets, including mortgage liens on oil and natural gas properties having at least 80% of the reserve value as determined by reserve reports. At our election, interest is generally determined by reference to (i) the London interbank offered rate, or LIBOR, plus an applicable margin between 1.50% and 2.50% per annum; or (ii) a domestic bank prime rate plus an applicable margin between 0.00% and 1.00% per annum.

As of June 30, 2012, we had no borrowings and no outstanding letters of credit under our revolving credit facility. The revolving credit facility also contains certain financial covenants and customary events of default. If an event of default occurs and is continuing, the lenders under our revolving credit facility may declare all amounts outstanding under our revolving credit facility to be immediately due and payable. As of June 30, 2012, we were in compliance with the financial covenants of our revolving credit facility.

**Fair Value of Financial Instruments**

See Note 5 to our unaudited condensed consolidated financial statements for a discussion of our money market funds and derivative instruments and their related fair value measurements. See also Item 3. Quantitative and Qualitative Disclosures About Market Risk below.

**Critical Accounting Policies and Estimates**

There have been no material changes in our critical accounting policies and estimates from those disclosed in our 2011 Annual Report.

**Off-Balance Sheet Arrangements**

Currently, we do not have any off-balance sheet arrangements as defined by the SEC. In the ordinary course of business, we enter into various commitment agreements and other contractual obligations, some of which are not recognized in our consolidated financial statements in accordance with GAAP. See Note 11 to our unaudited condensed consolidated financial statements for a description of our commitments and contingencies.

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**Item 3. Quantitative and Qualitative Disclosures About Market Risk**

The following market risk disclosures should be read in conjunction with the quantitative and qualitative disclosures about market risk contained in our 2011 Annual Report, as well as with the unaudited condensed consolidated financial statements and notes thereto included in this Quarterly Report on Form 10-Q.

We are exposed to a variety of market risks including commodity price risk, interest rate risk and counterparty and customer risk. We address these risks through a program of risk management including the use of derivative instruments.

*Commodity price exposure risk.* We are exposed to market risk as the prices of oil and natural gas fluctuate as a result of changes in supply and demand and other factors. To partially reduce price risk caused by these market fluctuations, we have entered into derivative instruments in the past and expect to enter into derivative instruments in the future to cover a significant portion of our future production.

We utilize derivative financial instruments to manage risks related to changes in oil prices. As of June 30, 2012, we utilized put spreads, two-way collar options and three-way collar options to reduce the volatility of oil prices on a significant portion of our future expected oil production. A two-way collar is a combination of options: a sold call and a purchased put. The purchased put establishes a minimum price (floor) and the sold call establishes a maximum price (ceiling) we will receive for the volumes under contract. A three-way collar is a combination of options: a sold call, a purchased put and a sold put. The purchased put establishes a minimum price (floor), unless the market price falls below the sold put (sub-floor), at which point the minimum price would be WTI plus the difference between the purchased put and the sold put strike price. The sold call establishes a maximum price (ceiling) we will receive for the volumes under contract. A put spread is a combination of a purchased put and a sold put, and in this case does not include a sold call, allowing the volumes under this contract to have no established maximum price (ceiling).

We recognize all derivative instruments at fair value. The credit standing of our counterparties is analyzed and factored into the fair value amounts recognized on the balance sheet. Derivative assets and liabilities arising from our derivative contracts with the same counterparty are also reported on a net basis, as all counterparty contracts provide for net settlement.

The following is a summary of our derivative contracts as of June 30, 2012:

| Settlement Period | Derivative Instrument | Total Notional Amount of Oil (Barrels) | Average Sub-Floor Price | Average Floor Price | Average Ceiling Price | Fair Value Asset (Liability) (In thousands) |
|---|---|---|---|---|---|---|
| 2012 | Two-Way Collars | 1,189,500 | | $ 89.23 | $ 108.76 | $ 7,906 |
| 2012 | Three-Way Collars | 1,860,000 | $ 66.39 | $ 90.33 | $ 109.70 | 12,093 |
| 2013 | Two-Way Collars | 201,500 | | $ 89.23 | $ 108.76 | 1,533 |
| 2013 | Three-Way Collars | 2,023,420 | $ 65.30 | $ 92.51 | $ 112.63 | 13,978 |
| 2013 | Put Spreads | 1,717,080 | $ 70.71 | $ 91.24 | | 12,853 |
| 2014 | Three-Way Collars | 827,030 | $ 71.08 | $ 92.58 | $ 114.15 | 3,714 |
| 2014 | Put Spreads | 150,970 | $ 71.03 | $ 91.03 | | 1,104 |
| 2015 | Three-Way Collars | 62,000 | $ 72.50 | $ 92.50 | $ 114.40 | 243 |
| | | | | | | $ 53,424 |

*Interest rate risk.* We had (i) $400.0 million of senior unsecured notes at a fixed cash interest rate of 7.25% per annum and (ii) $400.0 million of senior unsecured notes at a fixed cash interest rate of 6.5% per annum outstanding at June 30, 2012. During the first six months of 2012, we had no indebtedness outstanding under our revolving credit facility. We may utilize interest rate derivatives to alter interest rate exposure in an attempt to reduce interest rate expense related to existing debt issued under our revolving credit facility. Interest rate derivatives would be used solely to modify interest rate exposure and not to modify the overall leverage of the debt portfolio.

*Counterparty and customer credit risk.* Joint interest receivables arise from billing entities which own partial interest in the wells we operate. These entities participate in our wells primarily based on their ownership in leases on which we choose to drill. We have limited ability to control participation in our wells. We are also subject to credit risk due to concentration of our oil and natural gas receivables with several significant customers. The inability or failure of our significant customers to meet their obligations to us or their insolvency or liquidation may adversely affect our financial results. In addition, our oil and natural gas derivative arrangements expose us to credit risk in the event of nonperformance by counterparties. However, in order to mitigate the risk of nonperformance, we only enter into derivative contracts with counterparties that are high credit-quality financial institutions, most of which are lenders under our revolving credit facility. This risk is also managed by spreading our derivative exposure across several institutions and limiting the hedged volumes placed under individual contracts.

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While we do not require all of our customers to post collateral and we do not have a formal process in place to evaluate and assess the credit standing of our significant customers for oil and natural gas receivables and the counterparties on our derivative instruments, we do evaluate the credit standing of such counterparties as we deem appropriate under the circumstances. This evaluation may include reviewing a counterparty s credit rating, latest financial information and, in the case of a customer with which we have receivables, their historical payment record, the financial ability of the customer s parent company to make payment if the customer cannot and undertaking the due diligence necessary to determine credit terms and credit limits. Several of our significant customers for oil and natural gas receivables have a credit rating below investment grade or do not have rated debt securities. In these circumstances, we have considered the lack of investment grade credit rating in addition to the other factors described above.

We may, from time to time, purchase commercial paper instruments from high credit quality counterparties. These counterparties may include issuers in a variety of industries including the domestic and foreign financial sector. Our investment policy requires that our counterparties have minimum credit ratings thresholds and provides maximum counterparty exposure values. Although we do not anticipate any of our commercial paper issuers being unable to pay us upon maturity, we take a risk in purchasing the commercial paper instruments available in the marketplace. If a commercial paper issuer is unable to return investment proceeds to us at the maturity date, it could take a significant amount of time to recover all or a portion of the assets originally invested. Our commercial paper balance was $15.0 million at June 30, 2012.

Most of the counterparties on our derivative instruments currently in place are lenders under our revolving credit facility with investment grade ratings. We are likely to enter into any future derivative instruments with these or other lenders under our revolving credit facility, which also carry investment grade ratings. Furthermore, the agreements with each of the counterparties on our derivative instruments contain netting provisions. As a result of these netting provisions, our maximum amount of loss due to credit risk is limited to the net amounts due to and from the counterparties under the derivative contracts. We had a net derivative asset position of $53.4 million at June 30, 2012.

**Item 4. Controls and Procedures**

*Evaluation of disclosure controls and procedures.* As required by Rule 13a-15(b) of the Exchange Act, we have evaluated, under the supervision and with the participation of our management, including our Chief Executive Officer ( CEO ), our principal executive officer; Chief Financial Officer ( CFO ), our principal financial officer; and Chief Accounting Officer ( CAO ), the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) as of June 30, 2012. Our disclosure controls and procedures are designed to provide reasonable assurance that information required to be disclosed by us in the reports filed or submitted by us under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC s rules and forms, and that such information is accumulated and communicated to our management, including our CEO, CFO and CAO as appropriate, to allow timely decisions regarding required disclosure. Based on the evaluation, our CEO, CFO and CAO have concluded that our disclosure controls and procedures were effective at June 30, 2012.

*Changes in internal control over financial reporting.* During the quarter ended June 30, 2012, we converted to a new accounting and land software system, which replaced our existing system. We have taken the necessary steps to monitor and maintain appropriate internal controls during this period of change. These steps included procedures to preserve the integrity of the data converted and a review by management to validate the data converted. Additionally, we provided training related to this system to individuals using the system to carry out their job responsibilities. We anticipate that the implementation of this software will strengthen the overall system of internal controls due to enhanced automation and integration of related processes. In conjunction with this system conversion, we also brought all of our outsourced accounting functions in-house. We have continued to hire additional accounting staff to support these functions. We are modifying the design and documentation of internal control processes and procedures relating to the new system and modules to supplement and complement existing internal control over certain respective job areas. The system change was undertaken to integrate systems and consolidate information and was not undertaken in response to any actual or perceived deficiencies in our internal control over financial reporting. Testing of the controls related to the new system and accounting functions is ongoing and is included in the scope of our assessment of our internal control over financial reporting for 2012.

We continue to evaluate the ongoing effectiveness and sustainability of the changes we have made in internal control, and, as a result of the ongoing evaluation, may identify additional changes to improve internal control over financial reporting.

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## PART II OTHER INFORMATION

### Item 1. Legal Proceedings

See Part I, Item 1, Note 11 to our unaudited condensed consolidated financial statements entitled Commitments and Contingencies, which is incorporated in this item by reference.

### Item 1A. Risk Factors

Our business faces many risks. Any of the risks discussed elsewhere in this Form 10-Q and our other SEC filings could have a material impact on our business, financial position or results of operations. Additional risks and uncertainties not presently known to us or that we currently believe to be immaterial may also impair our business operations.

There have been no material changes in our risk factors from those described in our Annual Report on Form 10-K for the year ended December 31, 2011 and our Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2012. For a discussion of our potential risks and uncertainties, see the information in Item 1A. Risk Factors in our 2011 Annual Report and our Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2012.

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

*Unregistered sales of securities.* There were no sales of unregistered equity securities during the period covered by this report.

*Issuer purchases of equity securities.* The following table contains information about our acquisition of equity securities during the three months ended June 30, 2012:

| Period | Total Number of Shares Exchanged (1) | Average Price Paid per Share | Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs | Maximum Number (or Approximate Dollar Value) of Shares that May Be Purchased Under the Plans or Programs |
|---|---|---|---|---|
| April 1 April 30, 2012 | 306 | $ 30.83 | | |
| May 1 May 31, 2012 | 306 | 33.30 | | |
| June 1 June 30, 2012 | 234 | 23.79 | | |
| Total | 846 | $ 29.78 | | |

(1) Represent shares that employees surrendered back to the Company that equaled in value the amount of taxes needed for payroll tax withholding obligations upon the vesting of restricted stock awards. These repurchases were not part of a publicly announced program to repurchase shares of our common stock, nor do we have a publicly announced program to repurchase shares of common stock.

### Item 6. Exhibits

| Exhibit No. | Description of Exhibit |
|---|---|
| 4.1 | Second Supplemental Indenture dated as of July 2, 2012 among the Company, the Guarantors and U.S. Bank National Association, as trustee (filed as Exhibit 4.1 to the Company s Current Report on Form 8-K filed on July 2, 2012, and incorporated |

| | |
|---|---|
| | herein by reference). |
| 10.1 | Sixth Amendment to Amended and Restated Credit Agreement, dated as of April 3, 2012, among Oasis Petroleum North America, as borrower, Oasis Petroleum LLC, Oasis Petroleum Marketing LLC, Oasis Well Services LLC and Oasis Petroleum Inc., as guarantors, BNP Paribas, as administrative agent, and the lenders party thereto (filed as Exhibit 10.1 to the Company s Current Report on Form 8-K filed on April 5, 2012, and incorporated herein by reference). |
| 10.2 | April 20, 2012 Resignation, Consent and Appointment Agreement and Amendment Agreement (filed as Exhibit 10.1 to the Company s Current Report on Form 8-K filed on April 23, 2012, and incorporated herein by reference). |
| 31.1(a) | Sarbanes-Oxley Section 302 certification of Principal Executive Officer. |
| 31.2(a) | Sarbanes-Oxley Section 302 certification of Principal Financial Officer. |
| 32.1(b) | Sarbanes-Oxley Section 906 certification of Principal Executive Officer. |
| 32.2(b) | Sarbanes-Oxley Section 906 certification of Principal Financial Officer. |

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| Exhibit No. | Description of Exhibit |
|---|---|
| 101.INS (a) | XBRL Instance Document. |
| 101.SCH (a) | XBRL Schema Document. |
| 101.CAL (a) | XBRL Calculation Linkbase Document. |
| 101.DEF (a) | XBRL Definition Linkbase Document. |
| 101.LAB (a) | XBRL Labels Linkbase Document. |
| 101.PRE (a) | XBRL Presentation Linkbase Document. |

(a) Filed herewith.
(b) Furnished herewith.

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## SIGNATURES

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

| | |
|---|---|
| | **OASIS PETROLEUM INC.** |
| Date: August 7, 2012 | By: */s/ Thomas B. Nusz*<br>Thomas B. Nusz<br>Chairman, President and Chief Executive Officer<br><br>(Principal Executive Officer) |
| | By: */s/ Michael H. Lou*<br>Michael H. Lou<br>Executive Vice President and Chief Financial Officer<br><br>(Principal Financial Officer) |
| | By: */s/ Roy W. Mace*<br>Roy W. Mace<br>Senior Vice President, Chief Accounting Officer<br><br>(Principal Accounting Officer) |

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**EXHIBIT INDEX**

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(b) Furnished herewith.