PETROHAWK ENERGY CORP
Form PRE 14C
December 01, 2004

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

# SCHEDULE 14C

**INFORMATION REQUIRED IN INFORMATION STATEMENT**

**SCHEDULE 14C INFORMATION**

Information Statement Pursuant to Section 14(c) of
the Securities Exchange Act of 1934

Filed by the Registrant ý

Filed by a Party other than the Registrant o

Check the appropriate box:

ý Preliminary Information Statement

o **Confidential, for Use of the Commission Only (as permitted by Rule 14c-5(d)(2))**

o Definitive Information Statement

**PETROHAWK ENERGY CORPORATION**

(Name of Registrant as Specified In Its Charter)

Payment of Filing Fee (Check the appropriate box):

ý No fee required.

o Fee computed on table below per Exchange Act Rules 14-c-5(g) and 0-11.

(1) Title of each class of securities to which transaction applies:

(2) Aggregate number of securities to which transaction applies:

(3) Per unit price or other underlying value of transaction computed pursuant to Exchange Act Rule 0-11 (set forth the amount on which the filing fee is calculated and state how it was determined):

(4) Proposed maximum aggregate value of transaction:

(5) Total fee paid:

o Fee paid previously with preliminary materials.

o Check box if any part of the fee is offset as provided by Exchange Act Rule 0-11(a)(2) and identify the filing for which the offsetting fee was paid previously. Identify the previous filing by registration statement number, or the Form or Schedule and the date of its filing.

(1) Amount Previously Paid:

(2) Form, Schedule or Registration Statement No.:

(3) Filing Party:

(4) Date Filed:

# PETROHAWK ENERGY CORPORATION

**1100 LOUISIANA, SUITE 4400**
**HOUSTON, TEXAS 77002**

**December , 2004**

Dear Stockholder:

Petrohawk recently completed an important transaction. On November 23, 2004, we acquired Wynn-Crosby Energy, Inc. and nine of the limited partnerships it manages (the "Acquisition") for a cash purchase price of approximately $422 million.

To finance a portion of the purchase price, we issued $200 million of our Series B 8% Automatically Convertible Preferred Stock ("Series B preferred stock") to a group of qualified institutional buyers. The currently outstanding shares of Series B preferred stock are convertible into an aggregate of 25,806,450 shares of our common stock. We obtained an additional $210 million in debt financing through a new revolving credit facility and a second-lien term loan facility with BNP Paribas as the lead bank and administrative agent. In order to accommodate the issuance of our common stock upon conversion of the Series B preferred stock, our board of directors approved an amendment to our certificate of incorporation to increase the number of our authorized shares of common stock from 50 million to 75 million shares. In addition, our board approved an amendment to our 2004 Employee Incentive Plan to increase the aggregate number of shares that can be issued under the plan from 750,000 to 2,750,000.

PHAWK, LLC, which holds a majority of our outstanding common stock, approved the conversion of the Series B preferred stock into common stock, the amendment of our certificate of incorporation to increase our authorized shares of common stock from 50 million to 75 million shares, and the amendment of our 2004 Employee Incentive Plan to increase the aggregate number of shares of common stock that may be issued under the plan to a total of 2,750,000, each by written consent as permitted by the Delaware General Corporation Law and our bylaws. These written consents will become effective on the day following the twentieth day after we mail this information statement to our stockholders, or about December 31, 2004.

We are furnishing this information statement to provide you with important information about these matters. Please read the information statement carefully. We thank you for your continued support.

/s/ FLOYD C. WILSON

Floyd C. Wilson

*Chairman of the Board, President and*
*Chief Executive Officer*

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# PETROHAWK ENERGY CORPORATION

**1100 LOUISIANA, SUITE 4400**
**HOUSTON, TEXAS 77002**

**December , 2004**

## INFORMATION STATEMENT
## AND
## NOTICE OF ACTION TAKEN WITHOUT A MEETING

We are furnishing this information statement and notice of actions taken without a meeting to our stockholders in connection with the approval by our board of directors of the matters described below and the subsequent approval of these matters by written consent of the holder of a majority of our outstanding common stock. All corporate approvals in connection with these matters have been obtained and this information statement is furnished solely for the purpose of informing stockholders of these corporate actions in the manner required by the Securities Exchange Act of 1934, as amended (the "Exchange Act"), the Delaware General Corporation Law and our bylaws.

**WE ARE NOT ASKING YOU FOR A PROXY AND YOU ARE REQUESTED NOT TO SEND US A PROXY**

The record date for determining stockholders entitled to receive this information statement has been established as the close of business on November 29, 2004. On that date, there were 13,946,075 shares of our common stock, par value $0.001 per share, 598,271 shares of our Series A Convertible Preferred Stock ("Series A preferred stock"), and 2,580,645 shares of our Series B 8% Automatically Convertible Preferred Stock ("Series B preferred stock") issued and outstanding.

### ACTIONS APPROVED BY WRITTEN CONSENT

The corporate actions described in this information statement were approved on three separate occasions by the written consent of the holder of a majority of our outstanding common stock, par value $0.001 per share, in accordance with the Delaware General Corporation Law and our bylaws. Only holders of our common stock and Series A preferred stock were entitled to vote on matters submitted to our stockholders.

On October 29, 2004, PHAWK, LLC ("PHAWK"), the holder of a majority of our outstanding common stock, approved by written consent the issuance of shares of common stock underlying the shares of our Series B preferred stock. On that date, there were approximately 13.92 million shares of our common stock and 598,271 shares of our Series A preferred stock issued and outstanding.

On November 19, 2004, PHAWK approved by written consent the amendment to our certificate of incorporation to increase our authorized shares of common stock from 50 million to 75 million shares. On that date, there were approximately 13.95 million shares of our common stock and 598,271 shares of our Series A preferred stock issued and outstanding.

On November 29, 2004, PHAWK approved by written consent an amendment to our 2004 Employee Incentive Plan to increase the aggregate number of shares of common stock (including common stock options) that can be issued under the plan from 750,000 to 2,750,000 and to increase the number of shares of incentive and restricted stock issuable under the plan from 375,000 to 1,375,000 shares. On that date, there were approximately 13.95 million shares of our common stock, 598,271 shares of our Series A preferred stock, and 2.58 million shares of our Series B preferred stock issued and outstanding.

In accordance with the Exchange Act, the written consent and the approval of the matters described in the written consent will become effective on the day following the twentieth day after this information statement is mailed to our stockholders. This information statement is being mailed to stockholders on or about December 11, 2004.

**FORWARD-LOOKING STATEMENTS**

Included and incorporated by reference in this information statement are forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. All statements, other than statements of historical facts, included in or incorporated by reference into this information statement that address activities, events or developments that we expect or anticipate will or may occur in the future are forward-looking statements. The words "should," "believe," "intend," "expect," "anticipate," "project," "estimate," "predict," "plan" and similar expressions are also intended to identify forward-looking statements.

These forward-looking statements include, but are not limited to, statements regarding:

- estimates of proved reserve quantities and net present values of those reserves;
- estimates of probable and possible reserve quantities;
- reserve potential;
- business strategy;
- estimates of future commodity prices;
- amounts and types of capital expenditures and operating expenses;
- expansion and growth of our business and operations;
- expansion and development trends of the oil and natural gas industry;
- production of oil and natural gas reserves;
- exploration prospects;
- wells to be drilled, and drilling results;
- operating results and working capital; and
- future methods and types of financing.

Such forward-looking statements involve assumptions and are subject to known and unknown risks and uncertainties that could cause actual results or performance to differ materially from those expressed or implied by such forward-looking statements. Although we believe that the assumptions reflected in such forward-looking statements are reasonable, we can give no assurance that such assumptions will prove to have been correct. Forward-looking statements speak only as of the date they are made and we undertake no obligation to update them.

## INCORPORATION OF CERTAIN DOCUMENTS BY REFERENCE

We file annual, quarterly and current reports, proxy statements and other information with the SEC. Our proxy statement, filed April 23, 2004, our annual report on Form 10-K, as amended on April 20, 2004, for our fiscal year ended December 31, 2003, our proxy statement filed June 23, 2004, our quarterly report on Form 10-Q, for our quarter ended March 31, 2004, our quarterly report on Form 10-Q, for our quarter ended June 30, 2004, our quarterly report on Form 10-Q, for our quarter ended September 30, 2004, our current report on Form 8-K filed on May 25, 2004, our current report on Form 8-K filed on July 16, 2004, our current report on Form 8-K filed on July 20, 2004, our current report on Form 8-K as amended on July 27, 2004, our current report on Form 8-K filed on August 18, 2004, our current report on Form 8-K filed on September 20, 2004, our current report on Form 8-K as amended on October 21, 2004, our current report on Form 8-K filed on November 2, 2004, and our current report on Form 8-K filed on November 24, 2004, and our current report on Form 8-K/A filed on December 1, 2004 (excluding any information furnished pursuant to Item 9 or 7.01 or Item 12 or 2.02 of any such current report on Form 8-K) are incorporated by reference in, and are an integral part of, this information statement, and references to this "information statement" include the documents incorporated by reference into this information statement.

All documents filed by us pursuant to Sections 13(a), 13(c), 14 or 15(d) of the Exchange Act (excluding any information furnished pursuant to Item 2.02 or Item 7.01 on any current report on Form 8-K) subsequent to the date of this filing shall be deemed to be incorporated in this information statement and to be a part hereof from the date of the filing of such document. Any statement contained in a document incorporated by reference herein shall be deemed to be modified or superseded for all purposes to the extent that a statement contained in this information statement, or in any other subsequently filed document which is also incorporated or deemed to be incorporated by reference, modifies or supersedes such statement. Any statement so modified or superseded shall not be deemed, except as so modified or superseded, to constitute a part of this information statement.

## WHERE YOU CAN FIND MORE INFORMATION

Our SEC filings are available to the public over the Internet at the SEC's web site at *www.sec.gov*. You may also read and copy any document we file at the SEC's public reference rooms located at 450 Fifth Street, N.W., Washington D.C. 20549. Please call the SEC at 1-800-SEC-0330 for further information on the public reference rooms and their copy charges. In addition, through our website, *www.petrohawk.com*, you can access electronic copies of documents we file with the SEC, including our annual reports on Form 10-K, quarterly reports on Form 10-Q, and current reports on Form 8-K and any amendments to those reports. Information on our website is not incorporated by reference in this information statement. Access to those electronic filings is available as soon as practical after filing with the SEC.

## ACTIONS BY WRITTEN CONSENT

### Issuance of Shares of Our Common Stock Upon Conversion of Our Series B Preferred Stock

On November 23, 2004, we acquired Wynn-Crosby Energy, Inc. and nine of the limited partnerships it manages ("Wynn-Crosby") for total consideration of approximately $422 million in cash (the "Acquisition"). To finance a portion of the Acquisition purchase price, our Board approved the private offering and issuance of our Series B preferred stock. On November 23, 2004, we sold 2,580,645 shares of Series B preferred stock at $77.50 per share for a total of approximately $200 million. Each share of Series B preferred stock is convertible into ten (10) shares of common stock, or 25,806,450 shares in the aggregate, which would represent 46.6% of our fully diluted common stock. Because our common stock is traded on the Nasdaq National Market and we are therefore subject to Nasdaq Marketplace Rule 4350(i)(1)(c)(ii), we must obtain stockholder approval before issuing common stock equal to 20% or more of our outstanding common stock. Pursuant to Section 228 of Delaware General Corporation Law, the written consent of the holders of shares of our outstanding capital stock, having not less than the minimum number of votes that would be necessary to authorize or take such action at a meeting at which all shares entitled to vote thereon were present and voted, may be substituted for such meeting. On October 29, 2004, PHAWK, the holder of 7,575,757 shares of our common stock, representing a majority of our then outstanding voting power, approved by written consent the issuance of common stock upon conversion of all shares of Series B preferred stock.

**Increase in the Number of Authorized Shares of Our Common Stock**

To ensure that we will have a sufficient number of authorized but unissued shares of our common stock available for issuance upon the conversion of our Series B preferred stock, we must obtain stockholder approval of an amendment to our certificate of incorporation to increase our authorized shares of common stock from 50 million to 75 million shares.

PHAWK approved by written consent the amendment to our certificate of incorporation to increase our authorized shares of common stock to 75 million shares on November 19, 2004.

**Amendment to Our 2004 Employee Incentive Plan**

The 2004 Employee Incentive Plan was approved by our stockholders on July 15, 2004. This plan permits us to grant to our employees shares of common stock with no restrictions (referred to in the plan as "Incentive Stock"), shares of common stock with restrictions (referred to in the plan as "Restricted Stock") and options to purchase shares of our common stock. The maximum number of shares of common stock issuable under the 2004 Employee Incentive Plan is 750,000 shares (subject to adjustment in the event of a recapitalization or other corporate action affecting the number of shares outstanding). On November 29, 2004, PHAWK, the holder of 7,575,757 shares of our common stock, representing a majority of our then outstanding voting power, approved by written consent an amendment to our 2004 Employee Incentive Plan to increase the aggregate number of shares of common stock (including common stock options) that may be issued under the plan from 750,000 shares to 2,750,000 shares, and to increase the number of shares of Incentive Stock and Restricted Stock issuable under the plan from 375,000 shares to 1,375,000 shares.

**No Further Stockholder Action Needed**

As a result of these written consents, stockholder approval of the amendment to our certificate of incorporation, the issuance of our common stock upon conversion of the outstanding Series B preferred stock, and the amendment to our 2004 Employee Incentive Plan has been obtained. We were not required under the Delaware General Corporation Law, our certificate of incorporation or our bylaws to obtain stockholder approval to effect the Acquisition or issue the Series B preferred stock. Accordingly, all necessary corporate approvals in connection with the matters referred to herein have been obtained and no further votes will be needed. Under Exchange Act Rule 14c-2, the actions authorized by written consent will become effective on the day following the twentieth day after we first mailed this information statement to our stockholders, or about December 31, 2004. Our board of directors does not intend to solicit any proxies or consents in connection with the foregoing actions.

This information statement is furnished solely for the purpose of informing stockholders regarding the actions taken by written consent, and is being provided pursuant to the requirements of Rule 14c-2 promulgated under Section 13 of the Exchange Act.

**Reasons for the Actions Taken**

We sold 2,580,645 shares of Series B preferred stock for a total of approximately $200 million to finance a portion of the purchase price of the Acquisition. Issuance of the Series B preferred stock permitted us to complete the Acquisition on the terms and within the time period negotiated with the sellers. The increase of our authorized shares of common stock from 50 million to 75 million shares ensures that we will have a sufficient number of shares of common stock to issue upon the conversion of our Series B preferred stock.

The amendment to our 2004 Employee Incentive Plan will permit our board of directors to make stock options, Restricted Stock and Incentive Stock awards to our management and employees representing, in the aggregate, up to ten percent (10%) of our outstanding common stock. Our board of directors and management believe that the 2004 Employee Incentive Plan will help attract and retain competitively superior employees and promote long-term growth and profitability by aligning employee and stockholder interests. A summary of the essential features of the 2004 Employee Incentive Plan is provided below, but is qualified in its entirety by reference to the full text of the plan, which is incorporated herein by reference to our proxy statement filed with the SEC on June 23, 2004, and by reference to the amendment to the plan, which is attached to this information statement as Appendix B.

**Effects of the Proposed Issuance and the Amendment to Our 2004 Employee Incentive Plan**

The issuance of a significant amount of common stock upon conversion of our Series B preferred stock and/or the issuance of additional options or common stock under our 2004 Employee Incentive Plan may adversely affect the price of our common stock. We have agreed to file a registration statement to permit the public resale of the shares of common stock underlying the Series B preferred stock and certain shares of common stock held by PHAWK. The influx of such a substantial number of shares into the public market could also have a significant negative effect on the trading price of our common stock. As of November 29, 2004 approximately 13.95 million shares of common stock were outstanding, and approximately 41.5 million shares of common stock were issuable upon conversion or exercise of outstanding options, warrants, Series A preferred stock, Series B preferred stock and other convertible securities. An additional 25.8 million shares of common stock will be outstanding upon automatic conversion of the outstanding Series B preferred stock. Issuance of these shares of common stock, options or restricted stock may substantially dilute the ownership interests of our existing stockholders. The issuance of such additional shares of common stock or options may create downward pressure on the trading price of our common stock. In recent years broad stock market indices, in general, and smaller capitalization companies, in particular, have experienced substantial price fluctuations. In a volatile market, we may experience wide fluctuations in the market price of our common stock. These fluctuations may also have a negative effect on the market price of our common stock.

## NO DISSENTER'S RIGHTS

The corporate action described in this information statement will not afford to stockholders the opportunity to dissent from the actions described herein or to receive an agreed or judicially appraised value for their shares.

## INTEREST OF CERTAIN PERSONS IN THE ACTIONS TAKEN

No person who has been an officer or director of Petrohawk since the beginning of January 1, 2003 has any substantial interest by security holding or otherwise, in the issuance of the shares of common stock underlying the outstanding shares of our Series B preferred stock, the increase in the number of our authorized shares of common stock, or the amendment of our 2004 Employee Incentive Plan.

## THE COMPANY

We are an independent energy company engaged in the acquisition, development, production and exploration of natural gas and oil. Our properties are concentrated in the South Texas, East Texas, Anadarko, Arkoma and Permian Basin regions. As of July 1, 2004, on a pro forma basis including the recent acquisition of Wynn-Crosby and the August 2004 acquisition of properties in the Gulf Coast region from PHAWK, LLC, discussed below, we had estimated total net proved reserves of approximately 233 Bcfe, of which approximately 74% were natural gas and approximately 76% were classified as proved developed.

We have increased our proved reserves and production principally through acquisitions. We focus on properties within our core operating areas that have a significant proved reserve component and which management believes have additional development and exploration opportunities. Through the acquisition of the PHAWK properties, we have also acquired an interest in a number of exploratory drilling prospects defined by 79 square miles of recently reprocessed 3-D seismic data.

Petrohawk is a Delaware corporation originally organized in Nevada in June 1997 as "Beta Oil & Gas, Inc." Our principal offices are located at 1100 Louisiana Street, Suite 4400, Houston, Texas 77002, telephone number (832) 204-2700, fax number (832) 204-2800, and our website can be found at *www.petrohawk.com*. Unless specifically incorporated by reference in this information statement, information that you may find on our website is not part of this information statement.

**Recent Developments**

We have recently completed several transactions:

***Acquisition of Control by PHAWK, LLC.*** On May 25, 2004, PHAWK, LLC (formerly known as Petrohawk Energy, LLC), which is owned by affiliates of EnCap Investments, L.P., Liberty Energy Holdings LLC, Floyd C. Wilson and other members of our management, purchased a controlling interest in us for $60 million in cash. The $60 million investment was structured as the purchase by PHAWK of 7.576 million shares of our common stock for $25 million, a $35 million five year 8% subordinated note convertible into approximately 8.75 million shares of our common stock and warrants to purchase 5 million shares of our common stock at a price of $3.30 per share (after giving effect to a one-for-two reverse split of our common stock implemented in May 2004). As of October 26, 2004, PHAWK owned approximately 55% of our outstanding common stock, or approximately 77% assuming the exercise and conversion of all securities purchased by it in May 2004. After giving effect to the conversion of the Series B preferred stock into common stock, PHAWK will own approximately 19% of our outstanding common stock, or approximately 40% assuming the exercise and conversion of all securities purchased by it in May 2004. In connection with the investment by PHAWK, Mr. Wilson was named our Chairman, President and Chief Executive Officer, our board of directors and other management was changed, and our corporate offices were relocated from Tulsa, Oklahoma to Houston, Texas. Also, at our annual stockholders meeting held July 15, 2004, our stockholders approved changing the name of the company to Petrohawk Energy Corporation (from Beta Oil & Gas, Inc.), reincorporating the company in Delaware, and the adoption of new stock option plans.

***Acquisition of PHAWK Properties.*** On August 11, 2004, we acquired from PHAWK certain oil and gas properties in the Breton Sound area, Plaquemines Parish, Louisiana and in the West Broussard field in Lafayette Parish, Louisiana having approximately 2.9 Bcfe of estimated proved reserves. This purchase included the acquisition of 79 square miles of recently reprocessed 3-D seismic data and a 25% working interest in eight leased drilling prospects covering 2,528 gross acres in the Breton Sound/Main Pass area as well as two producing wells, pipelines and associated production facilities in Breton Sound Blocks 11 and 23. A 14% working interest (approximately 10% net revenue interest) was acquired in the Montesano #1 well in the West Broussard field. The Montesano #1 well was placed on production in August 2004. The purchase price for all of the proved reserves, seismic data, undeveloped acreage, pipelines, production facility and other assets was $8.5 million in cash. The effective date of the acquisition was June 1, 2004 and the effects of this transaction were first reported in our results for the quarter ending September 30, 2004.

***Acquisition of Wynn-Crosby.*** On November 23, 2004, we acquired Wynn-Crosby Energy, Inc. and nine of the limited partnerships it managed for a purchase price of approximately $422 million in cash after closing adjustments.

In connection with the Acquisition, Netherland, Sewell & Associates, Inc., our independent petroleum engineering consultants, evaluated the proved reserves associated with working interest properties, and our reserve engineers evaluated proved reserves associated with royalty interest properties, resulting in approximately 200 Bcfe of total estimated proved reserves at July 1, 2004. Additionally, 74% of the proved reserves are natural gas and 75% are classified as proved developed. Approximately 60% of the working interest proved reserves are operated.

The properties we acquired in the Acquisition are primarily located in the South Texas, East Texas, Anadarko, Arkoma and Permian Basin regions. Production for the six months ending June 30, 2004 averaged approximately 48 Mmcfe per day. The reserves-to-production ratio for these properties is estimated to be approximately 12 years.

The acquired properties include approximately 75,000 net undeveloped acres in the Arkoma Basin in Arkansas, as well as what we believe to be significant exploration opportunities in South Louisiana, South Texas and the Anadarko Basin.

Major properties in the Wynn-Crosby asset base include interests in La Reforma, a significant Vicksburg formation field in South Texas, the Dry Hollow and Provident City fields in the Wilcox trend of Lavaca County, Texas, and the Los Indios, Nabors, Ann Mag and McAllen Ranch fields in South Texas. In the East Texas basin, significant properties include interests in the South Carthage, North Beckville and Blocker fields. Other key properties include interests in the Waddell Ranch, Teague and ROC fields in the Permian Basin, the Kinta, Cedars, and Pine Hollow fields in the Arkoma Basin and the Lipscomb and Eakly-Weatherford fields in the Anadarko Basin.

***Credit Facilities.*** In connection with the Acquisition, we entered into a new revolving credit facility and a new second lien term loan facility, with BNP Paribas as the lead bank and administrative agent. The revolving credit facility is in the amount of $400 million, with an initial borrowing base of $200 million. $160 million was drawn on the revolving credit facility at the closing of the Acquisition. Borrowings under the facility are secured by a first priority lien on substantially all of our assets. The revolving credit facility contains customary financial and other covenants. The facility matures on November 23, 2008. The second lien facility is in the amount of $50 million and was fully drawn at the closing of the Acquisition. Borrowings under the second lien facility are secured by a second priority lien on substantially all of the assets securing the revolving credit facility. The second lien facility matures on February 24, 2009.

**Our Properties**

Information regarding our estimated proved reserves and properties is presented below. Information relating to estimated proved reserves and production volumes includes the recently acquired PHAWK properties and Wynn-Crosby properties, all as of the periods indicated. We acquired the PHAWK properties in August 2004 and the Wynn-Crosby properties on November 23, 2004.

| | July 2004 Estimated Average Net Daily Production | Proved Reserves at July 1, 2004(1) | |
|---|---|---|---|
| **Area** | **(Mmcfe/d)** | **Total (Bcfe)** | **Gas (%)** |
| Anadarko | 15.6 | 60.7 | 76.6 |
| South Texas | 15.0 | 55.1 | 88.3 |
| Permian Basin | 7.7 | 36.1 | 58.1 |
| East Texas | 3.3 | 20.3 | 84.4 |
| Arkoma | 5.3 | 20.1 | 81.8 |
| Gulf Coast(1) | 4.3 | 13.7 | 72.6 |
| Royalty Interests | 5.5 | 26.6 | 47.2 |
| Total | 56.7 | 232.6 | 74.0 |

(1) Includes approximately 2.9 Bcfe of estimated proved reserves we acquired from PHAWK on August 11, 2004 in the Breton Sound area, Plaquemines Parish, Louisiana and in the West Broussard field in Lafayette Parish, Louisiana.

Prior to the closing of the Acquisition, Wynn-Crosby, at our request, entered into the hedges reflected in the table below:

| | Gas Collars | | | Oil Collars | | |
|---|---|---|---|---|---|---|
| Time Period | Monthly Volume (Mmbtu) | Average NYMEX Floor Price/Mmbtu | Average NYMEX Ceiling Price/Mmbtu | Monthly Volume (Bbl) | Average NYMEX Floor Price/Bbl | Average NYMEX Ceiling Price/Bbl |
| 01/01/05 - 12/31/05 | 400,000 | $ 6.35 | $ 10.05 | 27,000 | $ 43.00 | $ 57.00 |
| 01/01/06 - 12/31/06 | 400,000 | 5.50 | 9.54 | 27,000 | 40.00 | 49.30 |
| 01/01/07 - 12/31/07 | 240,000 | 5.30 | 7.12 | 14,000 | 35.00 | 43.20 |
| 01/01/08 - 12/31/08 | 210,000 | 5.00 | 6.45 | | | |

Wynn-Crosby, at our request, also entered into an oil swap for 12,000 Bbls per month at 38.10 per Bbl for the 2008 calendar year.

In addition to the hedges entered into by Wynn-Crosby prior to the Acquisition, we had the following hedges in place at November 30, 2004:

| | Gas Collars | | | Oil Collars | | |
|---|---|---|---|---|---|---|
| Time Period | Monthly Volume (Mmbtu) | Average NYMEX Floor Price/Mmbtu | Average NYMEX Ceiling Price/Mmbtu | Monthly Volume (Bbl) | Average NYMEX Floor Price/Bbl | Average NYMEX Ceiling Price/Bbl |
| 01/01/05 - 12/31/05 | 170,000 | $ 5.68 | $ 7.89 | 9,000 | $ 43.00 | $ 52.30 |
| 01/01/06 - 12/31/06 | 150,000 | 6.00 | 8.26 | 7,000 | 40.00 | 47.30 |
| 01/01/07 - 12/31/07 | | | | 6,000 | 36.00 | 47.75 |
| 01/01/08 - 12/31/08 | 90,000 | 5.15 | 6.71 | 5,000 | 34.00 | 45.30 |

We have also put a gas swap in place for 100,000 Mmbtu per month for calendar 2007 at $6.06 per Mmbtu.

Our significant properties are described by area in the following paragraphs. The PHAWK properties and the Wynn-Crosby properties are included in the description.

***Anadarko Basin.*** The West Edmond Hunton Lime Unit (WEHLU) is our largest property in this region, covering 30,000 acres (approximately 47 square miles) primarily in Oklahoma County, Oklahoma. The WEHLU field, originally discovered in 1942, is the largest Hunton Lime field in the state of Oklahoma. The field has 58 oil and natural gas wells (28 currently producing) with stable production holding the entire unit. We own a 98% working interest at WEHLU and we are the operator. We have an agreement with Avalon Exploration, Inc. of Tulsa, Oklahoma to jointly develop additional reserves and production in WEHLU. The area of mutual interest created by our agreement with Avalon covers 5,680 acres located in the central-northwest area of the field.

Other significant properties in this area include interests in the Lipscomb field in Lipscomb County, Texas where our working interests range from 75% to 100% and the Eakly-Weatherford field in Caddo County, Oklahoma, where working interests range from 1% to 26%. Production in these fields is from the Cleveland, Atoka, Morrow and Springer formations.

***South Texas Area.*** Our properties in South Texas produce primarily from the Vicksburg, Wilcox and Frio formations which range in depth from approximately 5,500 feet to 12,500 feet. The La Reforma field, located in Starr and Hidalgo Counties, is the largest field in the Wynn-Crosby property base. La Reforma is a significant Vicksburg formation field and we own between 25% and 50% working interest in this area. We are conducting an active drilling program at La Reforma with one well currently being completed, one well currently drilling, and four locations expected to be drilled in 2005. The Vicksburg formation in this area is complexly faulted and 3-D seismic is extensively utilized to identify optimal structural targets. Wells in this field typically produce at initial rates of over 10.0 Mmcfe per day. Other Vicksburg/Frio fields in which we own a significant interest include Los Indios, Nabors, Ann Mag and McAllen Ranch. In the Wilcox trend of Lavaca County, we own between 20% and 25% working interest in the Dry Hollow field, which produces from 12,500 to 15,000 feet in depth. At Dry Hollow, we have identified three proved undeveloped locations and one location, which we expect to drill in 2005. We also own interests in the Provident City and North Borchers fields in Lavaca County.

***Permian Basin.*** In the Permian Basin, our principal properties are in the Waddell Ranch field in Crane County, Texas, the ROC field in Ward County, Texas, and the Teague field in Lea County, New Mexico. Waddell Ranch is the largest field in West Texas and produces primarily from the Grayburg, San Andres and Clear Fork formations at depths from 3,000 to 4,000 feet. We own a 3.5% working interest in this property. The ROC field produces from the Ellenberger and Montoya formations at measured depths of 13,000 to 17,000 feet. We have identified four proved undeveloped locations in this field, where we own a working interest of between 5% to 25%. In the Teague field, production is from the Devonian and Seven Rivers, Queen and Grayburg formations at a depth of 4,000 to 8,000 feet. We own a 94% working interest in this property and have identified two proved undeveloped locations.

***East Texas Area.*** Our properties in the East Texas basin produce primarily from the Cotton Valley and Travis Peak formations which range in depth from approximately 6,500 to 10,000 feet. We own significant interests in the South Carthage, North Beckville and Blocker fields in Panola and Harrison Counties, Texas. Our working interest in these fields is between 47% and 100%. The producing formations of this area tend to contain multiple producing horizons and are typically low permeability sands that require fracture stimulation to achieve optimal producing rates. This type of fracture stimulation usually results in relatively high initial production rates that decline rapidly during the first year of production and subsequently stabilize at fairly low, more easily predictable annual decline rates. Much of our production in this area is from wells that have been producing for several years and are in the latter, more stable stage of production, resulting in a relatively long reserves to production ratio.

***Arkoma Basin.*** In the Arkoma Basin, our properties produce primarily from the Atoka formation at depths of 2,500 to 6,000 feet. We own significant interests in the Kinta, Cedars and Pine Hollow fields in Pittsburg and Haskell Counties, Oklahoma. Our working interest in these fields is between 23% and 100%. Portions of our acreage in this region are near the Pine Hollow South field, where a new shale gas drilling play is currently evolving. In addition, we own approximately 75,000 net undeveloped acres in Logan, Scott and Yell Counties, Arkansas.

***Gulf Coast Area.*** Our largest property in the Gulf Coast region is the West Broussard field, which is located in Lafayette Parish, Louisiana. In 2003, the Failla #1 well was drilled and completed, with the well being placed on production in September 2003. Currently, the well is producing approximately 15.0 gross Mmcf of natural gas and 350 gross barrels of oil per day. We have an approximate 9% working interest in this well. An additional development well, the Montesano #1, was drilled and completed during the third quarter of 2004. The well was placed on production in August 2004 and is currently producing approximately 10.2 gross Mmcf of natural gas and 290 gross barrels of oil per day. We own a 23.1% working interest in this well, which will increase to approximately 29.6% working interest after payout. The Failla #1 and Montesano #1 wells produce from the Bol Mex 3 formation at approximately 15,830 feet.

Through the PHAWK properties acquisition, we acquired properties in the Breton Sound/Main Pass area in Louisiana state waters. This acquisition included 79 square miles of recently reprocessed 3-D seismic data and a 25% working interest in 8 leased drilling prospects covering 2,528 acres in the Breton Sound/Main Pass area, as well as two producing wells, pipelines and associated production facilities. The main objective formation is the Tex W at a depth of 11,500 feet. Wells in this area generally produce at high rates and are short lived.

In the Acquisition, we acquired between 5% and 12% working interest in the Ship Shoal 208/239 field located in federal waters, offshore Louisiana. In South Louisiana, we also own minor interests in the South Lake Arthur field, Vermilion Parish, which has produced over 1 Tcfe from the Myogyp formation. In addition, we own interests in Old Ocean, a large Frio formation field in Brazoria County, Texas.

***Royalty Interest Properties.*** Through the Acquisition, we own royalty interests in approximately 1,500 wells located in various oil and gas producing basins. As of July 2004, these non-cost bearing assets produced an estimated 5.5 Mmcfe per day and are approximately 55% gas on an equivalent production basis. The majority of these assets are located in the Permian Basin.

## FINANCING THE ACQUISITION

To finance the Acquisition and to fund working capital and capital expenditure requirements of the acquired business, on November 23, 2004 we issued approximately $200 million of our Series B preferred stock and incurred $210 in bank debt.

### Series B Preferred Stock

On November 23, 2004, we completed a private offering of 2,580,645 shares of Series B preferred stock pursuant to the private placement exception from registration provided in Regulation D, Rule 506, under Section 4(2) of the Securities Act. We received gross proceeds of approximately $200 million from the sale of our Series B preferred stock. We paid the placement agent a cash fee of $12 million for providing services as placement agent with respect to these shares. It is estimated that the total of all costs, expenses and fees in connection with the private offering, including the placement agent's reasonable out-of-pocket expenses, including financial advisory fees to third parties of approximately $1.5 million, will be approximately $15 million.

Shares of Series B preferred stock were offered and sold only to "qualified institutional buyers" (as defined in Rule 144A under the Securities Act) with whom the placement agent had a pre-existing relationship in reliance on applicable exemptions from registration provided under the Securities Act.

We expect the Series B preferred stock to convert into common stock on or about December 31, 2004. However, if such conversion has not occurred on or before March 31, 2005, holders of the Series B preferred stock are entitled to receive quarterly dividends accruing from the date of initial issuance at a rate of 8% per annum. Accrued and unpaid dividends on the Series B preferred stock that remain unpaid as of a quarterly dividend payment date will accrue additional dividends at a rate of 12% per annum until paid.

Upon our voluntary or involuntary liquidation, dissolution or winding up, holders of Series B preferred stock will be entitled to receive a liquidation preference of the initial issuance price plus accrued and unpaid dividends through the date of liquidation, before any payment or distribution is made to holders of common stock or other junior securities. We will be required to redeem all outstanding shares of the Series B preferred stock 91 days following the initial maturity date of our new senior revolving credit facility. The holders of the Series B preferred stock generally have no voting rights except as required by law or described below. If the conversion has not occurred by the earlier of the record date for our annual meeting of stockholders for 2005 or August 31, 2005, the holders of Series B preferred stock, voting separately as a class, will be entitled to elect two additional members to our board of directors. In addition, we may not, without the approval of the holders of two thirds of our Series B preferred stock, amend our certificate of designation or bylaws in a manner that would adversely impact the holders of Series B preferred stock, authorize or increase the authorized amount of any senior or parity securities, or liquidate or enter into any agreement regarding a change of control without providing for the redemption of the Series B preferred stock.

The Series B preferred stock and the common stock issuable upon conversion thereof have not been registered under the Securities Act or any state securities laws, and absent an effective registration statement, may not be offered or sold except to us or our subsidiaries or to a "qualified institutional buyer" (as defined in Rule 144A) pursuant to an exemption from registration. We have entered into a registration rights agreement for the benefit of the holders of Series B preferred stock sold in the private offering, pursuant to which we have agreed to use commercially reasonable efforts to (i) file with the SEC on or before December 31, 2004, a registration statement covering resales of common stock issuable upon conversion of the Series B preferred stock (and in certain circumstances, covering resales of the Series B preferred stock), and (ii) cause such registration statement to be declared effective by the SEC as promptly as reasonably practicable after it is filed. We filed a registration statement on Form S-3 with the SEC on December 1, 2004. In the event the registration statement is not declared effective before June 30, 2005, the dividend rate payable on the Series B preferred stock will increase to 8.5% per annum, and if the Series B preferred stock has been converted into common stock, we will make a quarterly payment of $0.01 per common share to the holders of the common stock until the registration statement has been declared effective.

For additional information about the terms of our Series B preferred stock and other outstanding capital stock, see "Description of Capital Stock."

**Debt Financing**

Petrohawk entered into two new credit facilities with BNP Paribas as lead bank and administrative agent. Set forth below is a summary of each of the facilities.

*Senior Revolving Credit Facility*

A senior revolving credit facility in the approximate amount of $400 million has been provided by BNP Paribas and a group of lenders. Availability under the revolver is restricted to the borrowing base. The initial borrowing base is $200 million, and such borrowing base will be subject to review and adjustment on a semi-annual basis. Amounts outstanding under the revolver bear interest at specified margins over the London Interbank Offered Rate ("LIBOR") of 1.25% to 2.5%. Such margins will fluctuate based on the utilization of the facility. Borrowings under the revolver are secured by first priority liens on substantially all of our assets, including equity interests in subsidiaries. We are subject to certain financial covenants pertaining to minimum working capital levels, minimum coverage of interest expenses, and a maximum leverage ratio. In addition, we are subject to covenants limiting dividends and other restricted payments, transactions with affiliates, incurrence of debt, changes of control, asset sales, and liens on properties. All amounts drawn under the revolver are due and payable on November 23, 2008. We have drawn $160 million on the senior revolving credit facility.

*Second Lien Term Loan Facility*

A second lien term loan facility in the amount of $50 million has been provided by BNP Paribas and a group of lenders. Any amounts repaid under the term loan may not be reborrowed. Borrowings under the term loan initially bear interest at LIBOR + 4.00%, increasing by 0.25% on a quarterly basis thereafter, subject to a ceiling of LIBOR + 5.00%. Borrowings under the term loan are secured by second priority liens on all of the assets (including equity interests) that secure the revolver. We are subject to certain financial covenants pertaining to a minimum asset coverage ratio and a maximum leverage ratio. In addition, we are subject to covenants limiting dividends and other restricted payments, transactions with affiliates, incurrence of debt, changes of control, asset sales, and liens on properties. We are obligated to repay 1% per annum of the original principal balance, with the remaining 96% of the original principal balance due and payable on February 24, 2009. We have borrowed the entire $50 million under the second lien term loan facility.

## THE WYNN-CROSBY ACQUISITION

On November 23, 2004, we acquired Wynn-Crosby Energy, Inc. ("WCE") and nine of the limited partnerships it managed for a purchase price of approximately $422 million in cash after closing adjustments. The Acquisition was structured as the merger of nine newly formed Texas limited partnerships wholly owned by Petrohawk into nine limited partnerships (the "Partnerships") managed by WCE, and the merger of a newly formed Texas corporation wholly owned by Petrohawk into WCE. As a result of the mergers, Petrohawk is the sole owner of the Partnerships and WCE.

We will treat the Acquisition as an asset purchase for federal income tax purposes. The merger agreement relating to the merger of the Partnerships is referred to as the "Partnerships Merger Agreement," and the agreement relating to the merger of WCE is referred to as the "WCE Merger Agreement."

Both merger agreements contain customary representations and warranties of the parties which relate to various aspects of the businesses, financial statements and other matters of the parties. The representations and warranties of WCE and the Partnerships survive the closing for a period of six (6) months and there are two separate holdback amounts that can be drawn against by Petrohawk under indemnification provisions in the agreements in the event of a breach of representations or warranties. The Partnerships Merger Agreement provides for a $9.5 million holdback and the WCE Merger Agreement provides for a $500,000 holdback. The Partnerships Merger Agreement provides that no claim can be made against the holdback until claims totaling $4.25 million have been made and the WCE Merger Agreement provides that no claim can be made against the holdback until claims totaling $50,000 have been made. In each case, after the respective deductible has been reached, the entire holdback is available for indemnification. No indemnification is available under either agreement (a) in excess of the holdback or (b) for claims first asserted after the six month notice period.

## SUMMARY HISTORICAL FINANCIAL DATA

### Summary Historical Financial Data Petrohawk Energy Corporation

The following table sets forth Petrohawk's summary consolidated historical financial data that has been derived from (a) the audited consolidated statements of income and cash flows for Petrohawk for each of the years ended December 31, 2001, 2002, and 2003 and the audited balance sheet for Petrohawk as of December 31, 2003, (b) the unaudited condensed consolidated statements of income for Petrohawk for each of the nine months ended September 30, 2003 and 2004, (c) the unaudited condensed consolidated statement of cash flows for Petrohawk for the nine months ended September 30, 2004 and the unaudited balance sheet for Petrohawk as of September 30, 2004, and (d) unaudited supplemental financial information for oil and gas producing activities for each of the years ended December 31, 2001, 2002 and 2003 set forth in the notes to Petrohawk's audited financial statements for the years ended December 31, 2001, 2002 and 2003, and from Petrohawk's records for the nine months ended September 30, 2004. This discussion excludes the effects of the Acquisition and related financial transactions. You should read this historical financial data together with "Management's Discussion and Analysis of Financial Condition and Results of Operations" and Petrohawk's consolidated financial statements and notes thereto incorporated by reference herein.

| | Year Ended December 31, | | | Nine Months Ended September 30, | |
|---|---|---|---|---|---|
| | 2001 | 2002 | 2003 | 2003 | 2004 |
| | (in thousands, except per share data) | | | | |
| **Statement of Income Data:** | | | | | |
| **REVENUES:** | | | | | |
| Oil and natural gas | $ 13,223 | $ 9,446 | $ 12,591 | $ 9,170 | $ 14,379 |
| Field services | 434 | 202 | 334 | 250 | 251 |
| **Total revenue** | 13,657 | 9,648 | 12,925 | 9,420 | 14,630 |
| **COSTS AND EXPENSES:** | | | | | |
| Production: | | | | | |
| Lease operations | 2,769 | 2,925 | 2,402 | 1,703 | 2,458 |
| Production, severance and ad valorem taxes | 852 | 533 | 875 | 654 | 781 |
| Field services | 340 | 195 | 185 | 144 | 131 |
| General and administrative | 2,527 | 2,057 | 2,678 | 1,907 | 4,017 |
| Stock-based compensation | | | 252 | 212 | 2,925 |
| Full cost ceiling impairment | 13,805 | 5,164 | 129 | | |
| Depreciation, depletion and amortization | 5,177 | 5,121 | 4,858 | 3,813 | 3,532 |
| Accretion of asset retirement obligations | | | 50 | 41 | 69 |
| **Total costs and expenses** | 25,470 | 15,995 | 11,429 | 8,474 | 13,913 |
| **INCOME (LOSS) FROM OPERATIONS** | (11,813) | (6,347) | 1,496 | 946 | 717 |
| **OTHER INCOME (EXPENSE):** | | | | | |
| Financial Derivatives unrealized | | | | | (592) |
| Interest expense | (868) | (558) | (476) | (367) | (1,279) |
| Interest income and other | 131 | 23 | (30) | 3 | 148 |
| **Total other income (expense)** | (737) | (535) | (506) | (364) | (1,723) |
| INCOME (LOSS) BEFORE INCOME TAX PROVISION | (12,550) | (6,882) | 990 | 582 | (1,006) |
| INCOME TAX (PROVISION) BENEFIT | 3,504 | | (24) | | 24 |
| INCOME (LOSS) BEFORE CUMULATIVE EFFECT OF CHANGE IN ACCOUNTING PRINCIPLE | (9,046) | (6,882) | 966 | 582 | (982) |
| CUMULATIVE EFFECT ON PRIOR YEARS FROM ADOPTION OF FASB STATEMENT NO. 143, ACCOUNTING FOR ASSET RETIREMENT OBLIGATION, | | | 2 | 2 | |

| | Year Ended December 31, | | | Nine Months Ended September 30, | |
|---|---|---|---|---|---|
| NET OF TAX | | | | | |
| NET INCOME (LOSS) | (9,046) | (6,882) | 968 | 584 | (982) |
| PREFERRED DIVIDENDS | (232) | (447) | (447) | (334) | (333) |
| NET INCOME (LOSS) APPLICABLE TO COMMON STOCKHOLDERS | $ (9,278) | $ (7,329) | $ 521 | $ 250 | $ (1,315) |
| BASIC NET INCOME (LOSS) PER COMMON SHARE(1) | $ (1.50) | $ (1.18) | $ 0.08 | $ (0.04) | $ (0.13) |
| DILUTED NET INCOME (LOSS) PER COMMON SHARE(1) | $ (1.50) | $ (1.18) | $ 0.08 | $ (0.04) | $ (0.13) |
| WEIGHTED AVERAGE SHARES OUTSTANDING(1):oman" SIZE="2"> | $ 136,247 | 2,869 | | $ (24,167) | $ 493,272 |

See Notes to Condensed Consolidated Financial Statements.

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**W&T OFFSHORE, INC. AND SUBSIDIARIES**

**CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS**

| | Six Months Ended June 30, 2011 | 2010 |
|---|---|---|
| | (In thousands) (Unaudited) | |
| **Operating activities:** | | |
| Net income | $ 73,824 | $ 70,185 |
| Adjustments to reconcile net income to net cash provided by operating activities: | | |
| Depreciation, depletion, amortization and accretion | 157,462 | 145,231 |
| Amortization of debt issuance costs and discount on indebtedness | 815 | 669 |
| Loss on extinguishment of debt | 20,663 | |
| Share-based compensation | 3,662 | 1,943 |
| Derivative (gain) loss | 6,508 | (13,270) |
| Cash payments on derivative settlements | (8,322) | (442) |
| Deferred income taxes | 35,726 | 2,945 |
| Changes in operating assets and liabilities: | | |
| Oil and natural gas receivables | (11,606) | (11,739) |
| Joint interest and other receivables | 14,107 | 21,931 |
| Insurance receivables | 12,583 | 29,879 |
| Income taxes | (14,957) | 91,513 |
| Prepaid expenses and other assets | (24,650) | (9,129) |
| Asset retirement obligations | (29,703) | (35,210) |
| Accounts payable and accrued liabilities | (6,382) | (62,542) |
| Other liabilities | 115 | 12,354 |
| Net cash provided by operating activities | 229,845 | 244,318 |
| **Investing activities:** | | |
| Acquisitions of significant property interests in oil and natural gas properties | (396,976) | (116,589) |
| Investment in oil and natural gas properties and equipment | (85,801) | (89,705) |
| Proceeds from sales of oil and natural gas properties and equipment | | 1,335 |
| Purchases of furniture, fixtures and other | (178) | (167) |
| Net cash used in investing activities | (482,955) | (205,126) |
| **Financing activities:** | | |
| Issuance of 8.5% Senior Notes | 600,000 | |
| Repurchase of 8.25% Senior Notes | (406,150) | |
| Borrowings of long-term debt revolving bank credit facility | 310,000 | 285,000 |
| Repayments of long-term debt revolving bank credit facility | (235,000) | (285,000) |
| Repurchase premium and debt issuance costs | (29,728) | |
| Dividends to shareholders | (5,957) | (4,481) |
| Net cash provided (used) in financing activities | 233,165 | (4,481) |
| Increase (decrease) in cash and cash equivalents | (19,945) | 34,711 |
| Cash and cash equivalents, beginning of period | 28,655 | 38,187 |
| Cash and cash equivalents, end of period | $ 8,710 | $ 72,898 |

See Notes to Condensed Consolidated Financial Statements.

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**W&T OFFSHORE, INC. AND SUBSIDIARIES**

**NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS**

**(Unaudited)**

**1. Basis of Presentation**

***Operations.*** W&T Offshore, Inc. and subsidiaries, referred to herein as W&T or the Company, is an independent oil and natural gas producer, active in the acquisition, exploitation, exploration and development of oil and natural gas properties primarily in the deepwater and deep shelf regions in the Gulf of Mexico. W&T has recently diversified its operations by expanding onshore primarily in the West Texas Permian Basin.

***Interim Financial Statements.*** The accompanying unaudited condensed consolidated financial statements have been prepared in accordance with generally accepted accounting principles ( GAAP ) for interim financial information and the appropriate rules and regulations of the Securities and Exchange Commission ( SEC ). Accordingly, the condensed consolidated financial statements do not include all of the information and footnote disclosures required by GAAP for complete financial statements. In the opinion of management, all adjustments (consisting of normal recurring accruals) considered necessary for a fair presentation have been included.

Operating results for interim periods are not necessarily indicative of the results that may be expected for the entire year. These unaudited condensed consolidated financial statements should be read in conjunction with the consolidated financial statements and notes thereto included in the Company s Annual Report on Form 10-K for the year ended December 31, 2010.

***Reclassifications.*** Certain reclassifications have been made to the prior periods financial statements to conform to the current presentation.

***Use of Estimates.*** The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting periods. Actual results could differ from those estimates.

**2. Acquisitions**

On May 11, 2011, we completed the acquisition of approximately 21,900 gross acres (21,500 net acres) of oil and gas leasehold interests in the West Texas Permian Basin (the Permian Basin Properties ) from Opal Resources LLC and Opal Resources Operating Company LLC ( Opal ). The stated purchase price was $366.3 million, subject to certain adjustments, including adjustments from an effective date of January 1, 2011. Taking into account adjustments through June 30, 2011, the purchase price was $399.5 million. The increase of $33.2 million primarily reflects drilling costs in excess of cash flow from the effective date of January 1, 2011 to the closing date of May 11, 2011. The purchase price is subject to further adjustments and we expect final settlement could occur as early as the third quarter of 2011. We acquired estimated proved reserves of approximately 30 million barrels of oil equivalent (182 Bcfe) (using a 6 to 1 Mcf to barrel equivalency) as of December 31, 2010, comprised of approximately 91% oil and natural gas liquids and which are approximately 78% proved undeveloped. The acquisition was funded from cash on hand and borrowings under our revolving bank credit facility.

During 2010, we closed on two major acquisition transactions. On April 30, 2010, through our wholly-owned subsidiary, W&T Energy VI, LLC ( Energy VI ), we acquired all of Total E&P USA s ( Total ) interest, including production platforms and facilities, in three federal offshore lease blocks located in the Gulf of Mexico and assumed the asset retirement obligations ( ARO ) for plugging and abandonment of the acquired interest. The purchase price was $121.3 million. The properties acquired from Total are producing interests and include a 100% working interest in the Matterhorn field (Mississippi Canyon block 243) and a 64% working interest in the Virgo field (Viosca Knoll blocks 822 and 823).

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**W&T OFFSHORE, INC. AND SUBSIDIARIES**

**NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

**(Unaudited)**

On November 4, 2010, through Energy VI, we acquired all of Shell Offshore Inc. s ( Shell ) interests, including production platforms and facilities, in three federal offshore lease blocks located in the Gulf of Mexico and assumed the ARO for plugging and abandonment of the acquired interest. The purchase price was $139.9 million. The properties acquired from Shell are producing interests and include a 70% working interest in the Tahoe field (Viosca Knoll 783), 100% working interest in the Southeast Tahoe field (Viosca Knoll 784) and a 6.25% of 8/8ths overriding royalty interest in the Droshky field (Green Canyon 244).

The Permian Basin Properties accounted for $11.1 million of revenue, $1.4 million of direct operating expenses, $2.4 million of depreciation, depletion, amortization and accretion ( DD&A ) and $2.6 million of income taxes, resulting in $4.8 million of net income for the three and six months ended June 30, 2011. The net income attributable to these properties does not reflect certain expenses, such as general and administrative expenses and interest expense; therefore this information is not intended to report results as if these operations were managed on a stand-alone basis. In addition, the Permian Basin Properties are not recorded in a separate entity for tax purposes; therefore income tax was estimated using the federal statutory tax rate.

Pro forma financial statements have been prepared due to the acquisition being significant to us. The unaudited pro forma financial information was computed as if the acquisition of the Permian Basin Properties had been completed on January 1, 2010. The historical financial information is derived from the unaudited historical consolidated financial statements of W&T and the unaudited historical statements of revenues and direct operating expenses of the Permian Basin Properties (which were based on information provided by Opal). The adjustments noted below assume the entire transaction was financed with borrowings because the cash and cash equivalents balances for the assumed acquisition date was less than the cash and cash equivalents on hand used on the actual closing date of May 11, 2011.

The pro forma adjustments were based on information and estimates by management to be directly related to the purchase of the Permian Basin Properties. The pro forma financial information is not necessarily indicative of the results of operations had the purchase occurred on January 1, 2010. If the transaction had been in effect for the periods indicated, the results may have been substantially different. For example, we may have operated the assets differently than Opal, realized sales prices may have been different and costs of operating the properties may have been different. The following tables present a summary of our pro forma consolidated statement of income (loss) for the six months ended June 30, 2011 and 2010 (in thousands except earnings per share):

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**W&T OFFSHORE, INC. AND SUBSIDIARIES**

**NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

**(Unaudited)**

| | Six Months Ended June 30, 2011 | | | |
|---|---|---|---|---|
| | Historical | Permian Basin Properties | Pro Forma Adjustments | Pro Forma |
| Revenues | $ 463,777 | $ 23,801 (a) | $ | $ 487,578 |
| Operating costs and expenses: | | | | |
| Lease operating expenses | 101,002 | 5,261 (a) | | 106,263 |
| Production taxes | 1,133 | 1,352 (a) | | 2,485 |
| Gathering and transportation | 8,350 | 10 (a) | | 8,360 |
| Depreciation, depletion and amortization | 141,618 | | 9,263 (b) | 150,881 |
| Asset retirement obligation accretion | 15,844 | | 10 (c) | 15,854 |
| General and administrative expenses | 36,131 | | (282)(d) | 35,849 |
| Derivative loss | 6,508 | | | 6,508 |
| Total costs and expenses | 310,586 | 6,623 | 8,991 | 326,200 |
| Operating income/(loss) | 153,191 | 17,178 | (8,991) | 161,378 |
| Interest expense: | | | | |
| Incurred | 22,192 | | 3,865 (e) | 26,057 |
| Capitalized | (3,491) | | (1,165)(f) | (4,656) |
| Loss on extinguishment of debt | 20,663 | | | 20,663 |
| Other income | 16 | | | 16 |
| Income/(loss) before income tax expense | 113,843 | 17,178 | (11,691) | 119,330 |
| Income tax expense | 40,019 | | 1,920 (g) | 41,939 |
| Net income/(loss) | $ 73,824 | $ 17,178 | $ (13,611) | $ 77,391 |
| Basic and diluted earnings per common share | $ 0.98 | | | $ 1.02 |

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**W&T OFFSHORE, INC. AND SUBSIDIARIES**

**NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

**(Unaudited)**

| | Six Months Ended June 30, 2010 | | | |
|---|---|---|---|---|
| | Historical | Permian Basin Properties | Pro Forma Adjustments | Pro Forma |
| Revenues | $ 349,252 | $ 12,043 (a) | $ | $ 361,295 |
| Operating costs and expenses: | | | | |
| Lease operating expenses | 87,823 | 1,695 (a) | | 89,518 |
| Production taxes | 512 | 575 (a) | | 1,087 |
| Gathering and transportation | 8,313 | 4 (a) | | 8,317 |
| Depreciation, depletion and amortization | 132,819 | | 13,857 (b) | 146,676 |
| Asset retirement obligation accretion | 12,412 | | 15 (c) | 12,427 |
| General and administrative expenses | 24,754 | | | 24,754 |
| Derivative (gain) | (13,270) | | | (13,270) |
| Total costs and expenses | 253,363 | 2,274 | 13,872 | 269,509 |
| Operating income/(loss) | 95,889 | 9,769 | (13,872) | 91,786 |
| Interest expense: | | | | |
| Incurred | 21,834 | | 5,489 (e) | 27,323 |
| Capitalized | (2,745) | | (1,548)(f) | (4,293) |
| Other income | 482 | | | 482 |
| Income/(loss) before income tax expense | 77,282 | 9,769 | (17,813) | 69,238 |
| Income tax expense/(benefit) | 7,097 | | (2,815)(g) | 4,282 |
| Net income/(loss) | $ 70,185 | $ 9,769 | $ (14,998) | $ 64,956 |
| Basic and diluted earnings per common share | $ 0.94 | | | $ 0.87 |

The purchase price is subject to further adjustments and we expect final settlement could occur as early as the third quarter of 2011. For these pro forma financial statements, the cash consideration is assumed to be funded entirely from borrowings from the revolving bank credit facility. The following table presents the purchase price allocation for the Permian Basin Properties as of June 30, 2011 (in thousands):

| | |
|---|---|
| Oil and natural gas properties and equipment (full cost method, $84,720 excluded from amortization) | $ 399,501 |
| Asset retirement obligation | (382) |
| Long-term liability | (2,143) |
| Total cash paid | $ 396,976 |

The following adjustments were made in the preparation of the condensed combined financial statements:

(a)

Revenues and direct operating expenses for the Permian Basin Properties were derived from the historical records of Opal up to the closing date of May 11, 2011.

(b) Depreciation, depletion and amortization ( DD&A ) was estimated using the full-cost method and determined as the incremental DD&A expense due to adding the Permian Basin costs, reserves and production into the computation. The purchase price allocation included $84.7 million allocated to the pool of unevaluated properties for oil and gas interests. Accordingly, no DD&A expense was estimated for the unevaluated properties.

(c) Asset retirement obligations and related accretion were estimated by the management of W&T.

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W&T OFFSHORE, INC. AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

(d) Incremental transaction expenses related to the purchase of Permian Basin Properties were $0.3 million and were assumed to be funded from cash on hand.

(e) Interest expense was computed using interest rates that were in effect during the applicable time period and it was assumed that six-month LIBOR borrowings were made as allowed under the revolving bank credit facility. The assumed interest rates ranged from 3.1% to 3.5%. A reduction in the revolving bank credit facility commitment fee related to the assumed borrowings was netted against the computed incremental interest expense.

(f) Incremental capitalized interest was computed for the addition of $84.7 million allocated to the pool of unevaluated properties and the capitalization interest rate was adjusted for the assumed borrowings.

(g) Income tax was computed using the 35% federal statutory rate.

**3. Hurricane Remediation and Insurance Claims**

During the third quarter of 2008, Hurricane Ike and, to a much lesser extent, Hurricane Gustav caused property damage and disruptions to our exploration and production activities. Our insurance policies in effect on the occurrence dates of Hurricanes Ike and Gustav had a retention requirement of $10 million per occurrence to be satisfied by us before we could be indemnified for losses. In the fourth quarter of 2008, we satisfied our $10 million retention requirement for Hurricane Ike in connection with two platforms that were toppled and were deemed total losses. Our insurance coverage policy limits at the time of Hurricane Ike were $150 million for property damage due to named windstorms (excluding certain damage incurred at our marginal facilities) and $250 million for, among other things, removal of wreckage if mandated by any governmental authority. The damage we incurred as a result of Hurricane Gustav was below our retention amount.

Below is a summary of remediation costs and amounts approved for payments related to Hurricanes Ike and Gustav that were included in lease operating expense (in thousands). Bracketed amounts represent credits to expense:

| | Three Months Ended June 30, | | Six Months Ended June 30, | |
|---|---|---|---|---|
| | 2011 | 2010 | 2011 | 2010 |
| Incurred and reversals of accruals | $ 114 | $ 2,229 | $ 76 | $ (1,878) |
| Plus amounts returned to insurers | | | 1,240 | |
| Less amounts approved for payment by insurers | (587) | (138) | (587) | (2,357) |
| Included in lease operating expense | $ (473) | $ 2,091 | $ 729 | $ (4,235) |

We recognize insurance receivables with respect to capital, repair and plugging and abandonment costs as a result of hurricane damage when we deem those to be probable of collection. Our assessment of probability considers the review and approval of such costs by our insurance underwriters adjuster. Claims that have been processed in this manner have customarily been paid on a timely basis. Incurred expenses included revisions of previous estimates. Amounts in 2011 include return of reimbursements that were previously received by us related to prepayments based on preliminary estimates. See Note 4 for additional information about the impact of hurricane related items on our asset retirement obligations.

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**W&T OFFSHORE, INC. AND SUBSIDIARIES**

**NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

**(Unaudited)**

Below is a reconciliation of our insurance receivables from December 31, 2010 to June 30, 2011 (in thousands):

| | |
|---|---|
| Balance, December 31, 2010 | $ 1,014 |
| Costs approved under our insurance policies, net | 17,841 |
| Payments received, net | (11,930) |
| Balance, June 30, 2011 | $ 6,925 |

At June 30, 2011 and December 31, 2010, substantially all of the amounts in insurance receivables relate to the plugging and abandonment of wells and dismantlement of facilities damaged by Hurricane Ike. We expect that our available cash and cash equivalents, cash flow from operations and the availability under our revolving bank credit facility will be sufficient to meet necessary expenditures that may exceed our insurance coverage for damages incurred as a result of Hurricane Ike.

**4. Asset Retirement Obligations**

Our asset retirement obligations primarily represent the estimated present value of the amount we will incur to plug, abandon and remediate our producing properties at the end of their productive lives in accordance with applicable laws. A summary of the changes to our asset retirement obligations is as follows (in thousands):

| | |
|---|---|
| Balance, December 31, 2010 | $ 391,316 |
| Liabilities settled | (29,703) |
| Accretion of discount | 15,844 |
| Liabilities assumed through acquisition | 382 |
| Liabilities incurred | 330 |
| Revisions of estimated liabilities due to Hurricane Ike | 6,628 |
| Revisions of estimated liabilities all other | 8,281 |
| Balance, June 30, 2011 | 393,078 |
| Less current portion | 105,379 |
| Long-term | $ 287,699 |

**5. Derivative Financial Instruments**

Our market risk exposure relates primarily to commodity prices and interest rates. From time to time, we use various derivative instruments to manage our exposure to commodity price risk from sales of oil and natural gas and interest rate risk from floating interest rates on our revolving bank credit facility. We do not enter into derivative instruments for speculative trading purposes. Our derivative instruments currently consist of commodity option contracts. We are exposed to credit loss in the event of nonperformance by the counterparties; however, we do not currently anticipate any of our counterparties being unable to fulfill their contractual obligations.

We account for derivative contracts in accordance with GAAP, which requires each derivative to be recorded on the balance sheet as an asset or a liability at its fair value. Changes in a derivative s fair value are required to be recognized currently in earnings unless specific hedge accounting criteria are met at the time we enter into a derivative contract. We have elected not to designate our commodity derivatives as hedging instruments. For additional information about fair value measurements, refer to Note 7.

***Commodity Derivative:*** During 2010, we entered into commodity option contracts to manage our exposure to commodity price risk from sales of oil through December 31, 2012. While these contracts are intended to reduce the effects of price volatility, they may also limit future income from favorable price movements. As of June 30, 2011, our open commodity derivatives were as follows:

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**W&T OFFSHORE, INC. AND SUBSIDIARIES**

**NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

**(Unaudited)**

**Zero Cost Collars Oil**

| Effective Date | Termination Date | Notional Quantity (Bbls) | Weighted Average NYMEX Contract Price Floor | Ceiling | Fair Value Liability (in thousands) |
|---|---|---|---|---|---|
| 7/1/2011 | 9/30/2011 | 231,900 | $ 75.00 | $ 93.02 | $ 934 |
| 10/1/2011 | 12/31/2011 | 392,100 | 75.00 | 95.58 | 2,714 |
| 1/1/2012 | 3/31/2012 | 364,000 | 75.00 | 97.88 | 2,726 |
| 4/1/2012 | 6/30/2012 | 364,000 | 75.00 | 97.88 | 3,186 |
| 7/1/2012 | 9/30/2012 | 124,000 | 75.00 | 97.88 | 1,152 |
| 10/1/2012 | 12/31/2012 | 251,000 | 75.00 | 98.99 | 2,357 |
| | | 1,727,000 | $ 75.00 | $ 96.86 | $ 13,069 |

At June 30, 2011, $9.6 million and $3.5 million were included in accrued liabilities and other long-term liabilities, respectively, related to our commodity derivative contracts. At December 31, 2010, $9.5 million and $5.4 million were included in accrued liabilities and other long-term liabilities, respectively, related to our commodity derivative contracts. Our derivative gain for the three months ended June 30, 2011 includes realized losses of $6.1 million and unrealized gains of $23.4 million related to our commodity derivatives. Our derivative loss for the six months ended June 30, 2011 includes realized losses of $8.3 million and unrealized gains of $1.8 million related to our commodity derivatives. Our derivative gain for the three months ended June 30, 2010 includes realized and unrealized gains of $2.1 million and $5.3 million, respectively, related to our commodity derivatives. Our derivative gain for the six months ended June 30, 2010 includes realized and unrealized gains of $3.2 million and $10.4 million, respectively, related to our commodity derivatives.

***Interest Rate Swap:*** Our interest rate swap contract with a fixed interest rate of 5.21% expired in August 2010. During the three months ended June 30, 2010, we recognized an unrealized gain of $1.8 million and a realized loss of $1.8 million for this contract. During the six months ended June 30, 2010, we recognized an unrealized gain of $3.3 million and a realized loss of $3.6 million for this contract.

**6. Long-Term Debt**

On June 10, 2011, we issued $600 million of our Senior Notes at par with an interest rate of 8.5% and maturity date of June 15, 2019 (the 8.5% Senior Notes ). Interest is payable semi-annually in arrears on June 15 and December 15 of each year beginning on December 15, 2011. The 8.5% Senior Notes are unsecured and are fully and unconditionally guaranteed by certain of our subsidiaries. The restrictive covenants and redemption provisions of the 8.5% Senior Notes are substantially similar to the terms of the 8.25% Senior Notes due 2014 (the 8.25% Senior Notes ). At June 30, 2011, the outstanding balance of our 8.5% Senior Notes was $600 million and was classified at their carrying value as long-term debt. The estimated annual effective interest rate on the 8.5% Senior Notes is 8.7% which includes amortization of debt issuance costs. At June 30, 2011, the estimated fair value of the 8.5% Senior Notes was approximately $606 million. For additional details about fair value measurements, refer to Note 7.

We used a portion of the net proceeds from the issuance of the 8.5% Senior Notes to fund a concurrent tender offer of our 8.25% Senior Notes, pursuant to which $406.2 million in principal amount of the 8.25% Senior Notes were tendered for repurchase. At June 30, 2011, the outstanding balance of our 8.25% Senior Notes was $43.9 million and was classified at their carrying value as short-term debt. At December 31, 2010, the outstanding balance of our 8.25% Senior Notes was $450 million and was classified at their carrying value as long-term debt. The estimated annual effective interest rate on the 8.25% Senior Notes during the six months ended June 30, 2011 was 8.4%. At June 30, 2011 and December 31, 2010, the estimated fair value of the 8.25% Senior Notes was approximately $45.7 million and $441 million, respectively. For additional details about fair value measurements, refer to Note 7. Costs related to the 8.25% Senior Notes that were repurchased pursuant to the tender offer, which includes the repurchase premium and a prorated amount of the unamortized debt issuance costs, are included in the statement of income within the line item classification, *Loss on extinguishment of debt,* in the amount of $20.0 million. See Note 13 for additional information regarding the remaining $43.9 million of 8.25% Senior Notes.

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**W&T OFFSHORE, INC. AND SUBSIDIARIES**

**NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

**(Unaudited)**

On May 5, 2011, we entered into a Fourth Amended and Restated Credit Agreement (the Credit Agreement ) which provides a revolving bank credit facility with an initial borrowing base of $525 million. This is a secured facility that is collateralized by our oil and natural gas properties. The Credit Agreement terminates on May 5, 2015 and replaces the prior Third Amended and Restated Credit Agreement (the Prior Credit Agreement ), which would have expired July 23, 2012. The pricing terms and restrictive covenants of the Credit Agreement are substantially similar to the terms of the Prior Credit Agreement. Availability under the Credit Agreement is subject to a semi-annual borrowing base determination set at the discretion of our lenders. The amount of the borrowing base is calculated by our lenders based on their evaluation of our proved reserves and their own internal criteria. Any determination by our lenders to change our borrowing base will result in a similar change in the availability under our revolving bank credit facility.

The initial borrowing base is reduced by $0.25 for every dollar of senior note indebtedness in excess of $450 million. Due to the issuance of the 8.5% Senior Notes, our borrowing base was reduced to $487.5 million.

The Credit Agreement contains covenants that restrict, among other things, the payment of cash dividends and share repurchases of up to $60 million per year, borrowings other than from the revolving bank credit facility, sales of assets, loans to others, investments, merger activity, hedging contracts, liens and certain other transactions without the prior consent of the lenders. Letters of credit may be issued up to $90 million, provided availability under the revolving bank credit facility exists. We are subject to various financial covenants calculated as of the last day of each fiscal quarter; including a minimum current ratio and a maximum leverage ratio as such ratios are defined in the Credit Agreement. We were in compliance with all applicable covenants of the Credit Agreement as of June 30, 2011.

Borrowings under the revolving bank credit facility bear interest at the applicable London Interbank Offered Rate ( LIBOR ) plus a margin that varies from 2.00% to 2.75% depending on the level of total borrowings under the Credit Agreement, or an alternative base rate equal to the applicable margin ranging from 1.00% to 1.75% plus the highest of the (a) the Prime Rate, (b) the Federal Funds Rate plus 0.50%, and (c) LIBOR plus 1.0%. The unused portion of the borrowing base is subject to a commitment fee of 0.50%. The estimated annual effective interest rate was 7.2% for the first six months of 2011 for borrowings under the Credit Agreement and the Prior Credit Agreement and includes amortization of debt issuance costs, commitment fees and other related costs.

Unamortized debt issuance costs related to the Prior Credit Agreement are included in the statement of income within the line item classification, *Loss on extinguishment of debt,* in the amount of $0.7 million.

At June 30, 2011, we had $75 million in borrowings and $0.5 million in letters of credit outstanding under the revolving bank credit facility. At December 31, 2010, we had no borrowings and $0.4 million in letters of credit outstanding under the revolving bank credit facility provided by the Prior Credit Agreement.

**7. Fair Value Measurements**

We measure the fair value of our derivative financial instruments by applying the income approach, using models with inputs that are classified within Level 2 of the valuation hierarchy. The inputs used for the fair value measurement of our derivative financial instruments are the exercise price, the expiration date, the settlement date, notional quantities, the implied volatility, the discount curve with spreads and published commodity futures prices. As described in Note 5, our derivative financial instruments are reported in the balance sheet at fair value and changes in fair value are recognized currently in earnings.

The fair value of our Senior Notes is based on quoted prices. The market for our Senior Notes is not an active market; therefore the fair value is classified within Level 2. The Senior Notes are reported in the balance sheet at their carrying value and their fair value is reported in Note 6.

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**W&T OFFSHORE, INC. AND SUBSIDIARIES**

**NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

**(Unaudited)**

**8. Share-Based Compensation and Cash-Based Incentive Compensation**

In 2010, the W&T Offshore, Inc. Amended and Restated Incentive Compensation Plan, ( the Plan ) was approved. As allowed by the Plan, in August 2010, the Company granted restricted stock units ( RSUs ) to certain of its employees and in January 2011, the Company granted restricted stock to one of its employees. RSUs are a long-term compensation component of the Plan, are granted to only certain employees, and are subject to adjustment based on the Company achieving certain predetermined performance criteria and vest at the end of a specified deferral period. Prior to 2010, the Company granted only restricted stock to its employees. In 2011 and in prior years, restricted stock was granted to the Company s non-employee directors under the Director Compensation Plan. In addition to share-based compensation, the Company may grant its employees cash-based incentive awards, which are a short-term component of the Plan, and are based on the Company and the employee achieving certain predetermined performance criteria.

We recognize compensation cost for share-based payments to employees and non-employee directors over the period during which the recipient is required to provide service in exchange for the award, based on the fair value of the equity instrument on the date of grant. We are also required to estimate forfeitures, resulting in the recognition of compensation cost only for those awards that actually vest.

At June 30, 2011, there were 2,152,377 shares of common stock available for award under the Plan and 568,783 shares of common stock available for award under the Directors Compensation Plan.

***Restricted Stock***: The Company currently has unvested restricted shares outstanding issued to employees and non-employee directors. Restricted shares are subject to forfeiture until vested and cannot be sold, transferred or disposed of during the restricted period. The holders of restricted shares generally have the same rights as a shareholder of the Company with respect to such shares, including the right to vote and receive dividends or other distributions paid with respect to the shares.

A summary of share activity related to restricted stock for the six months ended June 30, 2011 is as follows:

| | Restricted Stock | |
|---|---|---|
| | Shares | Weighted Average Grant Date Fair Value Per Share |
| Outstanding restricted shares, December 31, 2010 | 470,392 | $ 7.42 |
| Granted | 20,433 | 25.45 |
| Vested | (24,633) | 13.26 |
| Forfeited | (25,879) | 6.83 |
| Outstanding restricted shares, June 30, 2011 | 440,313 | 7.97 |

At June 30, 2011, the composition of our restricted stock awards outstanding, by year granted, was as follows:

| | Shares |
|---|---|
| Employees granted in: | |
| 2011 | 5,325 (1) |
| 2009 | 385,780 (2) |

| | |
|---|---|
| Non-employee directors granted in: | |
| 2011 | 15,108 (3) |
| 2010 | 23,330 (4) |
| 2009 | 10,770 (5) |
| Total | 440,313 |

Vesting is expected to occur, less any forfeitures, as follows:

(1) Equal installments in December 2011 and December 2012.
(2) December 2011.
(3) Equal installments in May 2012, 2013 and 2014.
(4) Equal installments in May 2012 and 2013.
(5) May 2012.

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**W&T OFFSHORE, INC. AND SUBSIDIARIES**

**NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

**(Unaudited)**

The grant date fair value of restricted stock granted during the six months ended June 30, 2011 and 2010 was $0.5 million and $0.4 million, respectively. The fair value of the shares that vested during the six months ended June 30, 2011 and 2010 was $0.6 million and $0.1 million, respectively.

***Restricted Stock Units:*** During 2010, the Company awarded to certain employees RSUs that were 100% contingent upon meeting a specified performance requirement, which was achieved in 2010. RSUs are subject to forfeiture until vested and cannot be sold, transferred or disposed of during the restricted period. Effective January 2011, RSUs awarded in 2010 earn dividend equivalents at the same rate as dividends paid on our common stock.

A summary of share activity related to RSUs for the six months ended June 30, 2011 is as follows:

| | Restricted Stock Units | |
|---|---|---|
| | Units (1) | Weighted Average Grant Date Fair Value Per Unit |
| Outstanding RSUs, December 31, 2010 | 1,266,617 | $ 9.36 |
| Granted | | |
| Vested | | |
| Forfeited | (33,096) | 9.36 |
| Outstanding RSUs, June 30, 2011 | 1,233,521 | 9.36 |

(1) All of the RSUs granted in 2010 will vest in December 2012 subject to employment conditions.

During the six months ended June 30, 2011 and 2010, there were no grants or vesting of RSUs.

***Share-Based Compensation:*** A summary of incentive compensation expense under share-based payment arrangements and the related tax benefit for the three and six months ended June 30, 2011 and 2010 is as follows (in thousands):

| | Three Months Ended June 30, | | Six Months Ended June 30, | |
|---|---|---|---|---|
| | 2011 | 2010 | 2011 | 2010 |
| Share-based compensation expense from: | | | | |
| Restricted stock | $ 603 | $ 747 | $ 1,191 | $ 1,943 |
| Restricted stock units | 1,232 | | 2,471 | |
| Total | $ 1,835 | $ 747 | $ 3,662 | $ 1,943 |
| Share-based compensation tax benefit: | | | | |
| Tax benefit computed at the statutory rate | $ 642 | $ 261 | $ 1,282 | $ 680 |

***Cash-based Incentive Compensation:*** As defined by the Plan, performance and annual incentive awards may be granted to eligible employees. These awards are performance-based awards consisting of one or more business criteria and individual performance criteria and a targeted level or levels of performance with respect to each of such criteria. Generally, the performance period is the calendar year and determination and payment is made in cash in the first quarter of the following year.

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**W&T OFFSHORE, INC. AND SUBSIDIARIES**

**NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

**(Unaudited)**

***Incentive Compensation:*** A summary of incentive compensation expense for the three and six months ended June 30, 2011 and 2010 is as follows (in thousands):

| | Three Months Ended June 30, | | Six Months Ended June 30, | |
|---|---|---|---|---|
| | **2011** | **2010** | **2011** | **2010** |
| Share-based compensation expense included in: | | | | |
| Lease operating expense | $ 116 | $ 159 | $ 233 | $ 428 |
| General and administrative | 1,719 | 588 | 3,429 | 1,515 |
| Total charged to operating income | 1,835 | 747 | 3,662 | 1,943 |
| Cash-based incentive compensation included in: | | | | |
| Lease operating expense | 1,119 | 651 | 2,199 | 777 |
| General and administrative | 3,288 | 2,377 | 6,052 | 2,911 |
| Total charged to operating income | 4,407 | 3,028 | 8,251 | 3,688 |
| Total incentive compensation charged to operating income | $ 6,242 | $ 3,775 | $ 11,913 | $ 5,631 |

As of June 30, 2011, unrecognized share-based compensation expense related to our outstanding restricted shares and RSUs was $1.7 million and $6.9 million, respectively. Unrecognized compensation expense will be recognized through April 2014 for restricted shares and November 2012 for RSUs.

**9. Income Taxes**

Income tax expense of $29.8 million and $40.0 million was recorded during the three and six months ended June 30, 2011, respectively. Our effective tax rate for the three and six months ended June 30, 2011 was 35.1% and 35.2%, respectively, which approximated the federal and state statutory rates. Income tax expense of $3.1 million and $7.1 million was recorded during the three and six months ended June 30, 2010, respectively. Our effective tax rate for the three and six months ended June 30, 2010 was 9.9% and 9.2% and primarily reflects a reduction in our valuation allowance that was recorded in prior years.

Exclusive of interest, the amount of unrecognized tax benefit recorded in other liabilities was $ 3.6 million as of June 30, 2011 and December 31, 2010. We recognize interest and penalties related to unrecognized tax benefits in income tax expense and these amounts were immaterial for the six months ended June 30, 2011 and 2010. The tax years from 2007 through 2010 remain open to examination by the applicable tax jurisdictions.

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W&T OFFSHORE, INC. AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

**10. Earnings Per Share**

The following table presents the calculation of basic earnings per common share for the three and six months ended June 30, 2011 and 2010 (in thousands, except per share amounts):

| | Three Months Ended June 30, | | Six Months Ended June 30, | |
|---|---|---|---|---|
| | 2011 | 2010 | 2011 | 2010 |
| Net income | $ 55,175 | $ 27,870 | $ 73,824 | $ 70,185 |
| Less portion allocated to nonvested shares | 1,178 | 379 | 1,558 | 957 |
| Net income allocated to common shares | $ 53,997 | $ 27,491 | $ 72,266 | $ 69,228 |
| Weighted average common shares outstanding | 74,020 | 73,669 | 74,012 | 73,665 |
| Basic and diluted earnings per common share | $ 0.73 | $ 0.37 | $ 0.98 | $ 0.94 |
| Shares excluded due to being anti-dilutive (weighted-average) | 1,683 | 1,017 | 1,699 | 1,021 |

**11. Dividends**

During the six months ended June 30, 2011 and 2010, we paid regular cash dividends of $0.04 and $0.03 per common share per quarter, respectively. On August 3, 2011, our board of directors declared a cash dividend of $0.04 per common share, payable on September 12, 2011 to shareholders of record on August 22, 2011.

**12. Contingencies**

We are a party to various pending or threatened claims and complaints seeking damages or other remedies concerning our commercial operations and other matters in the ordinary course of our business. In addition, claims or contingencies may arise related to matters occurring prior to our acquisition of properties or related to matters occurring subsequent to our sale of properties. In certain cases, we have indemnified the sellers of properties we have acquired, and in other cases, we have indemnified the buyers of properties we have sold. We are also subject to federal and state administrative proceedings conducted in the ordinary course of business. Although we can give no assurance about the outcome of pending legal and federal or state administrative proceedings and the effect such an outcome may have on us, management believes that any ultimate liability resulting from the outcome of such proceedings, to the extent not otherwise provided for or covered by insurance, will not have a material adverse effect on our consolidated financial position, results of operations or liquidity.

**13. Subsequent Event**

On July 18, 2011, we redeemed the remaining outstanding $43.9 million principal amount of our 8.25% Senior Notes, which would have matured in June 2014, at a redemption price of 104.125% plus accrued interest under the terms of the applicable indenture. These were 8.25% Senior Notes that were not tendered and repurchased during our tender offer conducted in June 2011. The redemption premium and remaining unamortized debt issuance costs of $2.0 million will be included in the statement of income within the line item classification, *Loss on extinguishment of debt,* in the third quarter of 2011.

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**W&T OFFSHORE, INC. AND SUBSIDIARIES**

**NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

**(Unaudited)**

**14. Supplemental Guarantor Information**

Our payment obligations under the 8.5% Senior Notes, the 8.25% Senior Notes and the Credit Agreement (see Note 6) are fully and unconditionally guaranteed by certain of our wholly-owned subsidiaries, Energy VI and W&T Energy VII, which does not have any active operations, (together, the Guarantor Subsidiaries ).

The following unaudited condensed consolidating financial information presents the financial condition, results of operations and cash flows of W&T Offshore, Inc. and other consolidated subsidiaries ( Parent Company ) and the Guarantor Subsidiaries, together with consolidating adjustments necessary to present the Company s results on a consolidated basis. Consolidated subsidiaries other than the Guarantor Subsidiaries are considered minor under applicable accounting rules of the SEC.

**Condensed Consolidating Balance Sheet as of June 30, 2011**

| | Parent Company | Guarantor Subsidiaries | Eliminations | Consolidated W&T Offshore, Inc. |
|---|---|---|---|---|
| | | (In thousands) | | |
| **Assets** | | | | |
| Current assets: | | | | |
| Cash and cash equivalents | $ 8,710 | $ | $ | $ 8,710 |
| Receivables: | | | | |
| Oil and natural gas sales | 69,201 | 22,316 | | 91,517 |
| Joint interest and other | 11,308 | | | 11,308 |
| Insurance | 6,925 | | | 6,925 |
| Income taxes | 45,830 | | (45,830) | |
| Total receivables | 133,264 | 22,316 | (45,830) | 109,750 |
| Deferred income taxes | | 9,183 | (9,183) | |
| Prepaid expenses and other assets | 44,153 | | | 44,153 |
| Total current assets | 186,127 | 31,499 | (55,013) | 162,613 |
| Property and equipment at cost: | | | | |
| Oil and natural gas properties and equipment | 5,435,135 | 272,493 | | 5,707,628 |
| Furniture, fixtures and other | 16,018 | | | 16,018 |
| Total property and equipment | 5,451,153 | 272,493 | | 5,723,646 |
| Less accumulated depreciation, depletion and amortization | 4,094,280 | 68,733 | | 4,163,013 |
| Net property and equipment | 1,356,873 | 203,760 | | 1,560,633 |
| Restricted deposits for asset retirement obligations | 33,921 | | | 33,921 |
| Other assets | 325,119 | 155,804 | (465,626) | 15,297 |
| Total assets | $ 1,902,040 | $ 391,063 | $ (520,639) | $ 1,772,464 |

| Liabilities and Shareholders Equity | | | | |
|---|---|---|---|---|
| Current liabilities: | | | | |
| Accounts payable | $ 64,285 | $ 1,351 | $ | $ 65,636 |
| Undistributed oil and natural gas proceeds | 35,937 | 326 | | 36,263 |
| Asset retirement obligations | 105,348 | | 31 | 105,379 |
| Accrued liabilities | 23,331 | | | 23,331 |
| Income taxes | | 48,426 | (45,830) | 2,596 |
| Deferred income taxes current | 2,249 | | | 2,249 |
| Long-term debt - current | 43,850 | | | 43,850 |
| Total current liabilities | 275,000 | 50,103 | (45,799) | 279,304 |
| Long-term debt | 675,000 | | | 675,000 |
| Asset retirement obligations, less current portion | 256,593 | 31,136 | (30) | 287,699 |
| Deferred income taxes | 33,989 | | (9,183) | 24,806 |
| Other liabilities | 168,186 | | (155,803) | 12,383 |
| Commitments and contingencies | | | | |
| Shareholders equity: | | | | |
| Common stock | 1 | | | 1 |
| Additional paid-in capital | 381,191 | 236,944 | (236,944) | 381,191 |
| Retained earnings | 136,247 | 72,880 | (72,880) | 136,247 |
| Treasury stock, at cost | (24,167) | | | (24,167) |
| Total shareholders equity | 493,272 | 309,824 | (309,824) | 493,272 |
| Total liabilities and shareholders equity | $ 1,902,040 | $ 391,063 | $ (520,639) | $ 1,772,464 |

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**W&T OFFSHORE, INC. AND SUBSIDIARIES**

**NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

**(Unaudited)**

**Condensed Consolidating Balance Sheet as of December 31, 2010**

| | Parent Company | Guarantor Subsidiaries | Eliminations | Consolidated W&T Offshore, Inc. |
|---|---|---|---|---|
| | | (In thousands) | | |
| **Assets** | | | | |
| Current assets: | | | | |
| Cash and cash equivalents | $ 28,655 | $ | $ | $ 28,655 |
| Receivables: | | | | |
| Oil and natural gas sales | 50,421 | 29,490 | | 79,911 |
| Joint interest and other | 25,415 | | | 25,415 |
| Insurance | 1,014 | | | 1,014 |
| Income taxes | 2,492 | | (2,492) | |
| Total receivables | 79,342 | 29,490 | (2,492) | 106,340 |
| Deferred income taxes | 5,784 | 2,755 | (2,755) | 5,784 |
| Prepaid expenses and other assets | 23,426 | | | 23,426 |
| Total current assets | 137,207 | 32,245 | (5,247) | 164,205 |
| Property and equipment at cost: | | | | |
| Oil and natural gas properties and equipment | 4,955,460 | 270,122 | | 5,225,582 |
| Furniture, fixtures and other | 15,841 | | | 15,841 |
| Total property and equipment | 4,971,301 | 270,122 | | 5,241,423 |
| Less accumulated depreciation, depletion and amortization | 3,994,085 | 27,310 | | 4,021,395 |
| Net property and equipment | 977,216 | 242,812 | | 1,220,028 |
| Restricted deposits for asset retirement obligations | 30,636 | | | 30,636 |
| Deferred income taxes | 2,819 | | | 2,819 |
| Other assets | 275,461 | 47,160 | (316,215) | 6,406 |
| Total assets | $ 1,423,339 | $ 322,217 | $ (321,462) | $ 1,424,094 |
| **Liabilities and Shareholders Equity** | | | | |
| Current liabilities: | | | | |
| Accounts payable | $ 77,422 | $ 3,020 | $ | $ 80,442 |
| Undistributed oil and natural gas proceeds | 24,866 | 374 | | 25,240 |
| Asset retirement obligations | 92,575 | | | 92,575 |
| Accrued liabilities | 25,827 | | | 25,827 |
| Income taxes | | 20,044 | (2,492) | 17,552 |
| Total current liabilities | 220,690 | 23,438 | (2,492) | 241,636 |
| Long-term debt | 450,000 | | | 450,000 |

| | | | | |
|---|---|---|---|---|
| Asset retirement obligations, less current portion | 269,016 | 29,725 | | 298,741 |
| Deferred income taxes | 2,755 | | (2,755) | |
| Other liabilities | 59,135 | | (47,161) | 11,974 |
| Commitments and contingencies | | | | |
| Shareholders equity: | | | | |
| Common stock | 1 | | | 1 |
| Additional paid-in capital | 377,529 | 236,944 | (236,944) | 377,529 |
| Retained earnings | 68,380 | 32,110 | (32,110) | 68,380 |
| Treasury stock, at cost | (24,167) | | | (24,167) |
| Total shareholders equity | 421,743 | 269,054 | (269,054) | 421,743 |
| Total liabilities and shareholders equity | $ 1,423,339 | $ 322,217 | $ (321,462) | $ 1,424,094 |

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**W&T OFFSHORE, INC. AND SUBSIDIARIES**

**NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

**(Unaudited)**

**Condensed Consolidating Statement of Income for the Three Months Ended June 30, 2011**

| | Parent Company | Guarantor Subsidiaries | Eliminations | Consolidated W&T Offshore, Inc. |
|---|---|---|---|---|
| | (In thousands) | | | |
| Revenues | $ 192,527 | $ 60,395 | $ | $ 252,922 |
| Operating costs and expenses: | | | | |
| Lease operating expenses | 38,066 | 10,531 | | 48,597 |
| Production taxes | 845 | | | 845 |
| Gathering and transportation | 3,249 | 548 | | 3,797 |
| Depreciation, depletion and amortization | 56,432 | 19,448 | | 75,880 |
| Asset retirement obligation accretion | 6,784 | 706 | | 7,490 |
| General and administrative expenses | 16,892 | 1,110 | | 18,002 |
| Derivative (gain) | (17,332) | | | (17,332) |
| Total costs and expenses | 104,936 | 32,343 | | 137,279 |
| Operating income | 87,591 | 28,052 | | 115,643 |
| Earnings of affiliates | 18,234 | | (18,234) | |
| Interest expense: | | | | |
| Incurred | 12,056 | | | 12,056 |
| Capitalized | (2,079) | | | (2,079) |
| Loss on extinguishment of debt | 20,663 | | | 20,663 |
| Interest income | 9 | | | 9 |
| Income before income tax expense | 75,194 | 28,052 | (18,234) | 85,012 |
| Income tax expense | 20,019 | 9,818 | | 29,837 |
| Net income | $ 55,175 | $ 18,234 | $ (18,234) | $ 55,175 |

**Condensed Consolidating Statement of Income for the Six Months Ended June 30, 2011**

| | Parent Company | Guarantor Subsidiaries | Eliminations | Consolidated W&T Offshore, Inc. |
|---|---|---|---|---|
| | (In thousands) | | | |
| Revenues | $ 332,753 | $ 131,024 | $ | $ 463,777 |
| Operating costs and expenses: | | | | |

| | | | | |
|---|---|---|---|---|
| Lease operating expenses | 80,147 | 20,855 | | 101,002 |
| Production taxes | 1,133 | | | 1,133 |
| Gathering and transportation | 6,321 | 2,029 | | 8,350 |
| Depreciation, depletion and amortization | 100,195 | 41,423 | | 141,618 |
| Asset retirement obligation accretion | 14,432 | 1,412 | | 15,844 |
| General and administrative expenses | 33,549 | 2,582 | | 36,131 |
| Derivative loss | 6,508 | | | 6,508 |
| Total costs and expenses | 242,285 | 68,301 | | 310,586 |
| Operating income | 90,468 | 62,723 | | 153,191 |
| Earnings of affiliates | 40,770 | | (40,770) | |
| Interest expense: | | | | |
| Incurred | 22,192 | | | 22,192 |
| Capitalized | (3,491) | | | (3,491) |
| Loss on extinguishment of debt | 20,663 | | | 20,663 |
| Interest income | 16 | | | 16 |
| Income before income tax expense | 91,890 | 62,723 | (40,770) | 113,843 |
| Income tax expense | 18,066 | 21,953 | | 40,019 |
| Net income | $ 73,824 | $ 40,770 | $ (40,770) | $ 73,824 |

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W&T OFFSHORE, INC. AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

**Condensed Consolidating Statement of Income for the Three Months Ended June 30, 2010**

| | Parent Company | Guarantor Subsidiaries (1) | Eliminations | Consolidated W&T Offshore, Inc. |
|---|---|---|---|---|
| | | (In thousands) | | |
| Revenues | $ 160,511 | $ 19,156 | $ | $ 179,667 |
| Operating costs and expenses: | | | | |
| Lease operating expenses | 46,546 | 5,911 | | 52,457 |
| Production taxes | 283 | | | 283 |
| Gathering and transportation | 3,512 | 214 | | 3,726 |
| Depreciation, depletion and amortization | 63,831 | 6,064 | | 69,895 |
| Asset retirement obligation accretion | 6,031 | 96 | | 6,127 |
| General and administrative expenses | 13,102 | 1,273 | | 14,375 |
| Derivative (gain) | (7,374) | | | (7,374) |
| Total costs and expenses | 125,931 | 13,558 | | 139,489 |
| Operating income | 34,580 | 5,598 | | 40,178 |
| Earnings of affiliates | 3,639 | | (3,639) | |
| Interest expense: | | | | |
| Incurred | 10,914 | | | 10,914 |
| Capitalized | (1,329) | | | (1,329) |
| Interest income | 354 | | | 354 |
| Income before income tax expense | 28,988 | 5,598 | (3,639) | 30,947 |
| Income tax expense | 1,118 | 1,959 | | 3,077 |
| Net income | $ 27,870 | $ 3,639 | $ (3,639) | $ 27,870 |

(1) Began operations on May 1, 2010. Includes only May and June of 2010.

**Condensed Consolidating Statement of Income for the Six Months Ended June 30, 2010**

| | Parent Company | Guarantor Subsidiaries (1) | Eliminations | Consolidated W&T Offshore, Inc. |
|---|---|---|---|---|
| | | (In thousands) | | |
| Revenues | $ 330,096 | $ 19,156 | $ | $ 349,252 |

| | | | | |
|---|---|---|---|---|
| Operating costs and expenses: | | | | |
| Lease operating expenses | 81,912 | 5,911 | | 87,823 |
| Production taxes | 512 | | | 512 |
| Gathering and transportation | 8,099 | 214 | | 8,313 |
| Depreciation, depletion and amortization | 126,755 | 6,064 | | 132,819 |
| Asset retirement obligation accretion | 12,316 | 96 | | 12,412 |
| General and administrative expenses | 23,481 | 1,273 | | 24,754 |
| Derivative (gain) | (13,270) | | | (13,270) |
| Total costs and expenses | 239,805 | 13,558 | | 253,363 |
| Operating income | 90,291 | 5,598 | | 95,889 |
| Earnings of affiliates | 3,639 | | (3,639) | |
| Interest expense: | | | | |
| Incurred | 21,834 | | | 21,834 |
| Capitalized | (2,745) | | | (2,745) |
| Interest income | 482 | | | 482 |
| Income before income tax expense | 75,323 | 5,598 | (3,639) | 77,282 |
| Income tax expense | 5,138 | 1,959 | | 7,097 |
| Net income | $ 70,185 | $ 3,639 | $ (3,639) | $ 70,185 |

(1) Began operations on May 1, 2010. Includes only May and June of 2010.

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**W&T OFFSHORE, INC. AND SUBSIDIARIES**

**NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

**(Unaudited)**

**Condensed Consolidating Statement of Cash Flows for the Six Months Ended June 30, 2011**

| | Parent Company | Guarantor Subsidiaries | Eliminations | Consolidated W&T Offshore, Inc. |
|---|---|---|---|---|
| | | (In thousands) | | |
| **Operating activities:** | | | | |
| Net income | $ 73,824 | $ 40,770 | $ (40,770) | $ 73,824 |
| Adjustments to reconcile net income to net cash provided by operating activities: | | | | |
| Depreciation, depletion, amortization and accretion | 114,627 | 42,835 | | 157,462 |
| Amortization of debt issuance costs and discount on indebtedness | 815 | | | 815 |
| Loss on extinguishment of debt | 20,663 | | | 20,663 |
| Share-based compensation | 3,662 | | | 3,662 |
| Derivative loss | 6,508 | | | 6,508 |
| Cash payments on derivative settlements | (8,322) | | | (8,322) |
| Deferred income taxes | 42,154 | (6,428) | | 35,726 |
| Earnings of affiliates | (40,770) | | 40,770 | |
| Changes in operating assets and liabilities: | | | | |
| Oil and natural gas receivables | (18,779) | 7,173 | | (11,606) |
| Joint interest and other receivables | 14,107 | | | 14,107 |
| Insurance receivables | 12,583 | | | 12,583 |
| Income taxes | (43,339) | 28,382 | | (14,957) |
| Prepaid expenses and other assets | (24,650) | (108,643) | 108,643 | (24,650) |
| Asset retirement obligations | (29,703) | | | (29,703) |
| Accounts payable and accrued liabilities | (4,665) | (1,717) | | (6,382) |
| Other liabilities | 108,758 | | (108,643) | 115 |
| Net cash provided by operating activities | 227,473 | 2,372 | | 229,845 |
| **Investing activities:** | | | | |
| Acquisition of significant property interest in oil and natural gas properties | (396,976) | | | (396,976) |
| Investment in oil and natural gas properties and equipment | (83,429) | (2,372) | | (85,801) |
| Purchases of furniture, fixtures and other | (178) | | | (178) |
| Net cash used in investing activities | (480,583) | (2,372) | | (482,955) |
| **Financing activities:** | | | | |
| Issuance of 8.5% Senior Notes | 600,000 | | | 600,000 |
| Repurchase of 8.25% Senior Notes | (406,150) | | | (406,150) |
| Borrowings of long-term debt revolving bank credit facility | 310,000 | | | 310,000 |
| Repayments of long-term debt revolving bank credit facility | (235,000) | | | (235,000) |
| Repurchase premium and debt issuance costs | (29,728) | | | (29,728) |
| Dividends to shareholders | (5,957) | | | (5,957) |

| | | | | |
|---|---|---|---|---|
| Net cash provided by (used in) financing activities | 233,165 | | | 233,165 |
| Increase in cash and cash equivalents | (19,945) | | | (19,945) |
| Cash and cash equivalents, beginning of period | 28,655 | | | 28,655 |
| Cash and cash equivalents, end of period | $ 8,710 | $ | $ | $ 8,710 |

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**W&T OFFSHORE, INC. AND SUBSIDIARIES**

**NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

**(Unaudited)**

**Condensed Consolidating Statement of Cash Flows for the Six Months Ended June 30, 2010**

| | Parent Company | Guarantor Subsidiaries (1) | Eliminations | Consolidated W&T Offshore, Inc. |
|---|---|---|---|---|
| | (In thousands) | | | |
| **Operating activities:** | | | | |
| Net income | $ 70,185 | $ 3,639 | $ (3,639) | $ 70,185 |
| Adjustments to reconcile net income to net cash provided by operating activities: | | | | |
| Depreciation, depletion, amortization and accretion | 139,071 | 6,160 | | 145,231 |
| Amortization of debt issuance costs and discount on indebtedness | 669 | | | 669 |
| Share-based compensation | 1,943 | | | 1,943 |
| Derivative gain | (13,270) | | | (13,270) |
| Cash payments on derivative settlements | (442) | | | (442) |
| Deferred income taxes | 144 | 2,801 | | 2,945 |
| Earnings of affiliates | (3,639) | | 3,639 | |
| Changes in operating assets and liabilities: | | | | |
| Oil and natural gas receivables | (2,140) | (9,599) | | (11,739) |
| Joint interest and other receivables | 21,931 | | | 21,931 |
| Insurance receivables | 29,879 | | | 29,879 |
| Income taxes | 92,355 | (842) | | 91,513 |
| Prepaid expenses and other assets | (9,129) | (5,154) | 5,154 | (9,129) |
| Asset retirement obligations | (35,210) | | | (35,210) |
| Accounts payable and accrued liabilities | (65,537) | 2,995 | | (62,542) |
| Other liabilities | 17,508 | | (5,154) | 12,354 |
| Net cash provided by operating activities | 244,318 | | | 244,318 |
| **Investing activities:** | | | | |
| Acquisition of significant property interests in oil and natural gas properties | | (116,589) | | (116,589) |
| Investment in oil and natural gas properties and equipment | (89,705) | | | (89,705) |
| Proceeds from sales of oil and natural gas properties and equipment | 1,335 | | | 1,335 |
| Investment in subsidiary | (116,589) | | 116,589 | |
| Purchases of furniture, fixtures and other | (167) | | | (167) |
| Net cash used in investing activities | (205,126) | (116,589) | 116,589 | (205,126) |
| **Financing activities:** | | | | |
| Borrowings of long-term debt revolving bank credit facility | 285,000 | | | 285,000 |
| Repayments of long-term debt revolving bank credit facility | (285,000) | | | (285,000) |
| Dividends to shareholders | (4,481) | | | (4,481) |
| Investment from parent | | 116,589 | (116,589) | |

| | | | | |
|---|---|---|---|---|
| Net cash provided by (used in) financing activities | (4,481) | 116,589 | (116,589) | (4,481) |
| Increase in cash and cash equivalents | 34,711 | | | 34,711 |
| Cash and cash equivalents, beginning of period | 38,187 | | | 38,187 |
| Cash and cash equivalents, end of period | $ 72,898 | $ | $ | $ 72,898 |

(1) Began operations on May 1, 2010. Includes only May and June of 2010.

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**Item 2. Management s Discussion and Analysis of Financial Condition and Results of Operations**
**Forward-Looking Statements**

The following discussion and analysis should be read in conjunction with our accompanying unaudited condensed consolidated financial statements and the notes to those financial statements included in Item 1 of this Quarterly Report on Form 10-Q. The following discussion contains forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995, Section 27A of the Securities Act of 1933 and Section 21E of the Exchange Act, that involve risks, uncertainties and assumptions. If the risks or uncertainties materialize or the assumptions prove incorrect, our results may differ materially from those expressed or implied by such forward-looking statements and assumptions. All statements other than statements of historical fact are statements that could be deemed forward-looking statements, such as those statements that address activities, events or developments that we expect, believe or anticipate will or may occur in the future. These statements are based on certain assumptions and analyses made by us in light of our experience and perception of historical trends, current conditions, expected future developments and other factors we believe are appropriate in the circumstances. Certain factors that may affect our financial condition and results of operations are discussed in Item 1A Risk Factors and Item 7A Quantitative and Qualitative Disclosures About Market Risk of our Annual Report on Form 10-K for the year ended December 31, 2010 and may be discussed or updated from time to time in subsequent reports filed with the SEC. We assume no obligation, nor do we intend, to update these forward-looking statements. Unless the context requires otherwise, references in this Quarterly Report on Form 10-Q to W&T, we, us, our and the Company refer to W&T Offshore Inc. and its consolidated subsidiaries.

**Overview**

W&T is an independent oil and natural gas producer focused primarily in the Gulf of Mexico. W&T has grown through acquisitions, exploitation and exploration and currently holds working interests in approximately 67 producing or capable of producing fields in federal and state waters. The majority of our daily production was derived from offshore wells we operate. In May 2011, we closed on the acquisition of the Permian Basin Properties as described below. After completing this acquisition, we now hold working interests in over 30,000 net acres onshore primarily in the West Texas Permian Basin. Acquiring these onshore properties has diversified our business by having both significant offshore and onshore operations.

Our financial condition, cash flow and results of operations are significantly affected by the volume of our oil and natural gas production and the price that we receive for such production. Our production volumes for the first six months of 2011 was comprised of approximately 47% oil, condensate and natural gas liquids and 53% natural gas, determined using the ratio of six thousand cubic feet ( Mcf ) of natural gas to one barrel ( Bbl ) of crude oil, condensate or natural gas liquids. The conversion ratio does not assume price equivalency, and the price per one thousand cubic feet equivalent ( Mcfe ) for oil and natural gas liquids may differ significantly from the price per Mcf for natural gas. For example, for the first six months of 2011, our average realized price for oil and NGLs on a Mcfe basis was $15.72 compared to $4.37 per Mcf for natural gas. For the first six months of 2011, our combined total production of oil, condensate, natural gas liquids and natural gas was approximately 11.0% higher on a Mcfe basis than during the same period in 2010.

During May 2011, we completed the acquisition of approximately 21,900 gross acres (21,500 net acres) of oil and gas leasehold interests in the Permian Basin Properties from Opal. The stated purchase price was $366.3 million, subject to certain adjustments, including adjustments from an effective date of January 1, 2011. Taking into account adjustments through June 30, 2011, the purchase price was $399.5 million. The increase of $33.2 million primarily reflects drilling costs in excess of cash flow from the effective date of January 1, 2011 to the closing date of May 11, 2011. The purchase price is subject to further adjustments and we expect final settlement could occur as early as the third quarter of 2011. We acquired estimated proved reserves of approximately 30 million barrels of oil equivalent (182 Bcfe) (using a 6 to 1 Mcf to barrel equivalency) as of December 31, 2010, comprised of approximately 91% oil and natural gas liquids and which are approximately 78% proved undeveloped. The properties include interests in producing wells, which produced approximately 2,534 net barrels of oil equivalents per day for the month of June 2011. Capital expenditures associated with planned development activities for these properties from the closing date of May 11, 2011 to December 31, 2011 are currently estimated to be between $40 million and $50 million. The acquisition was funded from cash on hand and borrowings under our revolving bank credit facility.

During 2010, we closed on two major acquisitions. In April 2010, we acquired property interests from Total and in November 2010, we acquired property interests from Shell. These transactions are described in *Financial Statements - Note 2 Acquisitions* under Part I, Item 1 of this Form 10-Q.

On March 31, 2011, the third-party pipeline used by our Main Pass 108, 98 and 180 fields, which had been offline since June 2010, became operational. In the second quarter of 2011, we gradually increased production in this area and in June 2011, it produced approximately 41 MMcfe per day, made up of 29,700 Mcf of natural gas and 1,937 barrels of oil/NGLs per day. Production in the second quarter of 2011 was impacted due to a shut down of our Matterhorn field for approximately one month for repairs, which had an average production of approximately 3,900 Boe per day in the month prior to the shutdown.

Prices for oil have continued to be volatile in 2011. The West Texas Intermediate posted spot price for oil was $98.08 per barrel for the first six months of 2011, representing an increase of 25.3% from $78.30 for the first six months of 2010. The price for oil during the first six months of 2011 ranged from a low of $83.13 per barrel to a high of $113.39 per barrel and during the first six months of 2010 prices ranged from $64.78 to $86.54 per barrel. For the first six months of 2011, our average realized sales price for oil and NGLs increased by 33.8% over the comparable period in 2010. Oil prices continue to be impacted by market fundamentals such as supply and demand and also by political events and disruptions throughout the world such as events in Japan, Africa and the Middle East. Long-term forecasts for oil demand, and therefore global oil prices, continue to be favorable in several key growing markets, specifically China and India.

The wide spreads between West Texas Intermediate crude and other crudes have continued since the early part of 2011. A significant majority of our oil production, which is located in south Louisiana, has received price premiums between $7.00 and $15.00 per barrel in the first six months of 2011. In comparison, the average premium spread between Light Louisiana Sweet crude and West Texas Intermediate crude was approximately $3.00 per barrel during 2010. We may continue to experience higher premiums to West Texas Intermediate crude in our future sales of crude oil until such time as the causative factors are resolved. We cannot predict with any certainty how long such pricing conditions will last.

Natural gas prices are much more affected by domestic issues, such as supply, local demand issues and domestic economic conditions. The Henry Hub posted spot price for natural gas was $4.27 per MMBtu for the first six months of 2011, representing a decrease of 9.3% from $4.71 per MMBtu for the first six months of 2010. The price for natural gas in the first six months of 2011 ranged from a low of $3.70 per MMBtu to a high of $4.92 per MMBtu and the range in the first six months of 2010 was from $3.72 to $7.51 per MMBtu. During the first six months of 2011, the average realized sales price of our natural gas decreased 10.5% from the comparable period of 2010. We are expecting continued weakness in natural gas prices unless demand for natural gas increases as a result of a strong economic recovery, drilling activity subsides dramatically or forced production shut-ins occur. There is also a risk that, as a result of successful exploration and development activities in the shale areas coupled with the availability of increasing amounts of liquefied natural gas, increased supplies of natural gas will offset or mitigate the impact of any natural gas shut-ins or demand increases resulting from improved economic conditions. According to industry sources, the rig count for horizontal drilling rigs, used primarily in the shale formation areas such as Louisiana, Arkansas, Texas, North Dakota and Pennsylvania, has reached or exceeded record levels. Natural gas production and supply continues to exceed demand. Onshore natural gas producers have continued to drill in attempts to yield production sufficient to preserve existing leases. Seasonal weather conditions also impact the demand for and price of natural gas.

Should prices decline for oil and natural gas in the future, it would negatively impact our future oil and natural gas revenues, earnings and liquidity, and could result in ceiling test write-downs of the carrying value of our oil and natural gas properties, create issues with financial ratio compliance, and result in a reduction of the borrowing base associated with our credit agreement, depending on the severity of such declines. If those were to occur and were significant, it may limit the willingness of financial institutions and investors to provide capital to us and others in the oil and natural gas industry.

In April 2010, there was a fire and explosion aboard the Deepwater Horizon drilling platform operated by BP in ultra deep water in the Gulf of Mexico. As a result of the explosion and ensuing fire, the rig sank, causing loss of life, and created a major oil spill that produced economic, environmental and natural resource damage in the Gulf Coast region. In response to the explosion and spill, the Bureau of Ocean Energy Management, Regulation and Enforcement (the BOEMRE ) issued a series of Notices to Lessees ( NTLs ), and other significant changes in regulations. In addition, the BOEMRE implemented a six-month moratorium on drilling activities which began in May 2010. There also continue to be many proposed changes in laws, regulations, guidance and policy in response to the Deepwater Horizon explosion and spill. After the moratorium ended in 2010, it was not until March 2011 that deep water drilling permits began to be issued, and even then only sporadically, to continue drilling activities that had commenced prior to the Deepwater Horizon incident. Since March 2011, a small number of deepwater drilling permits have been issued, but at a much lower rate than prior to the Deepwater Horizon event. The most significant regulation changes since the Deepwater Horizon event are regulations related to assessing the potential environmental impact of future spills using worse case discharge scenarios, spill response documentation, compliance reviews, operator practices related to safety and implementing a safety and environmental

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management system. The new regulations and increased review process increases the time it takes to obtain drilling permits and increases the cost of operations. As these new regulations and guidance continue to evolve, we cannot estimate the cost and impact to our business at this time. The permitting process is also slow and inconsistent for shallow water work as well. We have not experienced delays in obtaining permits related to our onshore operations.

**Results of Operations**

The following table sets forth selected financial data for the periods indicated (all values are net to our interest unless indicated otherwise):

| | Three Months Ended June 30, (1) | | | | Six Months Ended June 30, (1) | | | |
|---|---|---|---|---|---|---|---|---|
| | **2011** | **2010** | **Change** | **%** | **2011** | **2010** | **Change** | **%** |
| | (In thousands, except percentages and per share data) | | | | | | | |
| **Financial:** | | | | | | | | |
| Revenues: | | | | | | | | |
| Oil and NGLs | $ 193,944 | $ 124,762 | $ 69,182 | 55.5% | $ 353,431 | $ 240,242 | $ 113,189 | 47.1% |
| Natural gas | 58,661 | 54,719 | 3,942 | 7.2% | 109,579 | 108,789 | 790 | 0.7% |
| Other | 317 | 186 | 131 | 70.4% | 767 | 221 | 546 | 247.1% |
| Total revenues | 252,922 | 179,667 | 73,255 | 40.8% | 463,777 | 349,252 | 114,525 | 32.8% |
| Operating costs and expenses: | | | | | | | | |
| Lease operating expenses (2) | 48,597 | 52,457 | (3,860) | (7.4%) | 101,002 | 87,823 | 13,179 | 15.0% |
| Production taxes | 845 | 283 | 562 | 198.6% | 1,133 | 512 | 621 | 121.3% |
| Gathering and transportation | 3,797 | 3,726 | 71 | 1.9% | 8,350 | 8,313 | 37 | 0.4% |
| Depreciation, depletion, amortization and accretion | 83,370 | 76,022 | 7,348 | 9.7% | 157,462 | 145,231 | 12,231 | 8.4% |
| General and administrative expenses | 18,002 | 14,375 | 3,627 | 25.2% | 36,131 | 24,754 | 11,377 | 46.0% |
| Derivative (gain) loss | (17,332) | (7,374) | (9,958) | 135.0% | 6,508 | (13,270) | 19,778 | NM |
| Total costs and expenses | 137,279 | 139,489 | (2,210) | (1.6%) | 310,586 | 253,363 | 57,223 | 22.6% |
| Operating income | 115,643 | 40,178 | 75,465 | 187.8% | 153,191 | 95,889 | 57,302 | 59.8% |
| Interest expense, net of amounts capitalized | 9,977 | 9,585 | 392 | 4.1% | 18,701 | 19,089 | (388) | (2.0%) |
| Loss on extinguishment of debt (3) | 20,663 | | 20,663 | NM | 20,663 | | 20,663 | NM |
| Other income | 9 | 354 | (345) | (97.5%) | 16 | 482 | (466) | (96.7%) |
| Income before income tax expense | 85,012 | 30,947 | 54,065 | 174.7% | 113,843 | 77,282 | 36,561 | 47.3% |
| Income tax expense | 29,837 | 3,077 | 26,760 | NM | 40,019 | 7,097 | 32,922 | 463.9% |
| Net income | $ 55,175 | $ 27,870 | $ 27,305 | 98.0% | $ 73,824 | $ 70,185 | $ 3,639 | 5.2% |
| Basic and diluted earnings per common share | $ 0.73 | $ 0.37 | $ 0.36 | 97.3% | $ 0.98 | $ 0.94 | $ 0.04 | 4.3% |

(1) During the second quarter of 2011, we acquired the Permian Basin Properties. During 2010, we acquired property interests from Total in the second quarter and property interests from Shell in the fourth quarter. These acquisitions affect the comparability of results between time periods.

(2) Included in lease operating expenses are repair expenses, insurance reimbursements and other items related to hurricane damage. For additional details about our hurricane related items, refer to *Financial Statements Note 3 Hurricane Remediation and Insurance Claims* under Part I, Item 1 of this Form 10-Q.

(3) In May 2011, we entered into the Fourth Amended and Restated Credit Agreement, which replaced the Prior Credit Agreement. Unamortized debt issuance costs of $0.7 million related to the Prior Credit Agreement were expensed. In June 2011, we conducted a tender offer for our 8.25% Senior Notes, pursuant to which $406.2 million of the $450 million were tendered and repurchased, which resulted in loss on extinguishment of debt of $20.0 million.

NM = percentage change not meaningful

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The following table sets forth selected financial and operating data for the periods indicated (all values are net to our interest unless indicated otherwise):

| | Three Months Ended June 30, (1) | | | | Six Months Ended June 30, (1) | | | |
|---|---|---|---|---|---|---|---|---|
| | **2011** | **2010** | **Change** | **%** | **2011** | **2010** | **Change** | **%** |
| **Operating:** | | | | | | | | |
| Net sales: | | | | | | | | |
| Natural gas (Bcf) | 13.2 | 12.3 | 0.9 | 7.3% | 25.1 | 22.3 | 2.8 | 12.6% |
| Oil and NGLs (MMBbls) | 1.9 | 1.7 | 0.2 | 11.8% | 3.7 | 3.4 | 0.3 | 8.8% |
| Total natural gas and oil (Bcfe) (2) | 24.8 | 22.8 | 2.0 | 8.8% | 47.5 | 42.8 | 4.7 | 11.0% |
| Total natural gas and oil (MMBoe) (2) | 4.1 | 3.8 | 0.3 | 7.9% | 7.9 | 7.1 | 0.8 | 11.3% |
| Average daily equivalent sales (MMcfe/d) | 273.0 | 250.5 | 22.5 | 9.0% | 262.7 | 236.2 | 26.5 | 11.2% |
| Average realized sales prices (Unhedged): | | | | | | | | |
| Natural gas ($/Mcf) | $ 4.45 | $ 4.47 | $ (0.02) | (0.4%) | $ 4.37 | $ 4.88 | $ (0.51) | (10.5%) |
| Oil and NGLs($/Bbl) | 99.72 | 70.97 | 28.75 | 40.5% | 94.29 | 70.48 | 23.81 | 33.8% |
| Natural gas equivalent ($/Mcfe) | 10.17 | 7.87 | 2.30 | 29.2% | 9.74 | 8.16 | 1.58 | 19.4% |
| Average realized sales prices (Hedged): | | | | | | | | |
| Natural gas ($/Mcf) | $ 4.45 | $ 4.65 | $ (0.20) | (4.3%) | $ 4.37 | $ 5.06 | $ (0.69) | (13.6%) |
| Oil and NGLs ($/Bbl) | 96.59 | 70.90 | 25.69 | 36.2% | 92.07 | 70.21 | 21.86 | 31.1% |
| Natural gas equivalent ($/Mcfe) | 9.92 | 7.97 | 1.95 | 24.5% | 9.56 | 8.24 | 1.32 | 16.0% |
| Average per Mcfe ($/Mcfe): | | | | | | | | |
| Lease operating expenses | $ 1.96 | $ 2.30 | $ (0.34) | (14.8%) | $ 2.13 | $ 2.05 | $ 0.08 | 3.9% |
| Gathering and transportation | 0.15 | 0.16 | (0.01) | (6.3%) | 0.18 | 0.19 | (0.01) | (5.3%) |
| Production costs | 2.11 | 2.46 | (0.35) | (14.2%) | 2.31 | 2.24 | 0.07 | 3.1% |
| Production taxes | 0.03 | 0.01 | 0.02 | 200.0% | 0.02 | 0.01 | 0.01 | 100.0% |
| Depreciation, depletion, amortization and accretion | 3.36 | 3.33 | 0.03 | 0.9% | 3.31 | 3.40 | (0.09) | (2.6%) |
| General and administrative expenses | 0.73 | 0.63 | 0.10 | 15.9% | 0.76 | 0.58 | 0.18 | 31.0% |
| | $ 6.23 | $ 6.43 | $ (0.20) | (3.1%) | $ 6.40 | $ 6.23 | $ 0.17 | 2.7% |
| Total number of offshore wells drilled (gross) | 2 | 2 | | | 3 | 5 | (2) | (40.0%) |
| Total number of onshore wells drilled (gross) | 9 | | 9 | NM | 10 | | 10 | NM |
| Total number of offshore productive wells drilled (gross) | 2 | 2 | | | 3 | 4 | (1) | (25.0%) |
| Total number of onshore productive wells drilled (gross) | 9 | | 9 | NM | 10 | | 10 | NM |

(1) During the second quarter of 2011, we acquired the Permian Basin Properties. During 2010, we acquired property interests from Total in the second quarter and property interests from Shell in the fourth quarter. These acquisitions affect the comparability of results between time periods.

(2) The conversion to cubic feet equivalent and barrels of equivalent measures determined using the ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or natural gas liquids (totals may not compute due to rounding). The conversion ratio does not assume price equivalency, and the price per Mcfe for oil and natural gas liquids may differ significantly from the price per Mcf for natural gas.

NM = percentage change not meaningful

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***Three Months Ended June 30, 2011 Compared to the Three Months Ended June 30, 2010***

*Revenues.* Total revenues increased $73.3 million, or 40.8%, to $252.9 million for the second quarter of 2011 as compared to the same period in 2010. Oil and NGL revenues increased $69.2 million, natural gas revenues increased $3.9 million and other revenues increased $0.2 million. The oil and NGL revenue increase was attributable to a 40.5% increase in the average realized sales price to $99.72 per barrel for the three months ended June 30, 2011 from $70.97 per barrel for the same period in 2010, combined with an increase of 11.8% in sales volumes. The sales volume increase for oil and NGL is primarily attributable to increases associated with the properties purchased from Shell in November of 2010. The increase in natural gas revenue resulted from a 7.3% increase in sales volumes, partially offset by a 0.4% decrease in the average realized natural gas sales price. For the three months ended June 30, 2011, the natural gas average realized sales price was $4.45 per Mcf compared to $4.47 per Mcf for the same period in 2010. The sales volume increase for natural gas is primarily attributable to increases associated with the properties acquired from Shell in 2010.

*Lease operating expenses.* Lease operating expenses, which include base lease operating expenses, insurance, workovers, maintenance on our facilities, and hurricane remediation costs net of insurance claims, decreased $3.9 million to $48.6 million in the second quarter of 2011 compared to the second quarter of 2010. On a per Mcfe basis, lease operating expenses decreased to $1.96 per Mcfe during the second quarter of 2011 compared to $2.30 per Mcfe during the second quarter of 2010. On a component basis, hurricane remediation costs net of insurance claims, base lease operating expenses, insurance premiums and workover costs decreased $2.6 million, $2.0 million, $1.8 million and $1.5 million, respectively, while facility expenses increased $4.1 million. Hurricane remediation costs net of insurance claims decreased due to lower repair expenses and higher claims submitted for reimbursement. The decrease in base lease operating expenses is primarily attributable to lower base operating expenses at the properties purchased from Total in 2010. The decrease in insurance resulted primarily from lower premiums on our insurance policies covering well control and hurricane damage. Workover costs decreased due to numerous projects undertaken in 2010 that did not reoccur in 2011. The increase in facility expenses is primarily attributable to work performed on the tendon tension monitoring system and mechanical repairs at our Matterhorn platform.

*Production taxes.* Production taxes increased to $0.8 million for the quarter compared to $0.3 million in the prior year due to the acquisition of the Permian Basin Properties and are currently not a large component of our operating costs. Most of our production is from federal waters where there are no production taxes while onshore operations are subject to production taxes.

*Gathering and transportation costs.* Gathering and transportation costs were basically flat for the quarter compared to the prior year.

*Depreciation, depletion, amortization and accretion ( DD&A ).* DD&A, including accretion for ARO, increased slightly to $3.36 per Mcfe for the second quarter of 2011 from $3.33 per Mcfe in the second quarter of 2010. On a nominal basis, DD&A increased to $83.4 million for the second quarter of 2011 from $76.0 million in the second quarter of 2010. The slight increase to DD&A on a per Mcfe basis was due to the acquisition of the Permian Basin Properties while DD&A on a nominal basis increased due to higher production volumes.

*General and administrative expenses ( G&A ).* G&A expenses increased to $18.0 million for the second quarter of 2011 from $14.4 million for the same period in 2010, primarily due to higher incentive compensation as a result of improved financial and operational performance, reduced overhead charges billed to joint interest operators and slightly higher salaries. On a per Mcfe basis, G&A was $0.73 per Mcfe for the second quarter of 2011, compared to $0.63 per Mcfe for the same period in 2010.

*Derivative (gain)/loss.* For the second quarter of 2011, our derivative gain of $17.3 million related entirely to a change in the fair value of our commodity derivatives as a result of changes in crude oil prices. For the second quarter of 2010, our derivative gain of $7.4 million related primarily to a gain from our commodity derivatives as a result of changes in crude oil and natural gas prices. For additional details about our derivatives, refer to *Financial Statements Note 5 Derivative Financial Instruments* under Part I, Item 1 of this Form 10-Q.

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*Interest expense*. Interest expense incurred increased to $12.1 million for the second quarter of 2011 from $10.9 million for the same period in 2010 primarily as a result of increased borrowings related to the funding of the acquisition of the Permian Basin Properties. Combined with cash on hand, funding was obtained initially through borrowings on the revolving bank credit facility. The borrowings on the revolving bank credit facility were subsequently reduced through the proceeds received from the issuance of our 8.5% Senior Notes. Additionally, the effective interest rate and outstanding principal of our long-term debt increased after consummation of the 8.5% Senior Notes issuance and the tender offer for the 8.25% Senior Notes (see *Liquidity and Capital Resources* below). During the second quarter of 2011 and 2010, $2.1 million and $1.3 million, respectively, of interest was capitalized to unevaluated oil and natural gas properties with the increase attributable to the acquisition of the Permian Basin Properties.

*Loss on extinguishment of debt.* The loss on extinguishment of debt of $20.7 million was attributable primarily to the repurchase premium related to the tender offer for the 8.25% Senior Notes. This offer was made concurrently with, and was funded using a portion of the proceeds from, the issuance of the 8.5% Senior Notes. The consent payment, unamortized debt issuance costs and other related expenses totaled $20.0 million. In addition, the previous revolving bank credit facility was replaced resulting in the write off of unamortized debt issuance costs of $0.7 million. For additional information about our long-term debt and revolving bank credit facility, refer to *Financial Statements Note 6 Long-Term Debt* under Part I, Item 1 of this Form 10-Q.

*Income tax expense.* Income tax expense increased to $29.8 million for the second quarter of 2011 compared to $3.1 million for the same period of 2010. Our effective tax rate for the second quarter of 2011 was 35.1%, which approximates the statutory rate. Our effective tax rate for the second quarter of 2010 was approximately 9.9% and primarily reflects a reduction in our valuation allowance that was recorded in prior years.

***Six Months Ended June 30, 2011 Compared to the Six Months Ended June 30, 2010***

*Revenues*. Total revenues increased $114.5 million, or 32.8%, to $463.8 million for the first six months of 2011 as compared to the same period in 2010. Oil and NGL revenues increased $113.2 million, natural gas revenues increased $0.8 million and other revenues increased $0.5 million. The oil and NGL revenue increase was attributable to a 33.8% increase in the average realized sales price to $94.29 per barrel for the six months ended June 30, 2011 from $70.48 per barrel for the same period in 2010, combined with an increase of 8.8% in sales volumes. The sales volume increase for oil and NGL is primarily attributable to increases associated with the properties purchased from Shell in November 2010 and Total in April of 2010. The increase in natural gas revenue resulted from a 12.6% increase in sales volumes, partially offset by a 10.5% decrease in the average realized natural gas sales price to $4.37 per Mcf for the six months ended June 30, 2011 from $4.88 per Mcf for the same period in 2010. The sales volume increase for natural gas is primarily attributable to increases associated with the properties purchased from Total and Shell in 2010.

*Lease operating expenses.* Lease operating expenses, which include base lease operating expenses, insurance, workovers, maintenance on our facilities, and hurricane remediation costs net of insurance claims, increased $13.2 million to $101.0 million in the first six months of 2011 compared to the first six months of 2010. On a per Mcfe basis, lease operating expenses increased to $2.13 per Mcfe during the first six months of 2011 compared to $2.05 per Mcfe during the first six months of 2010. On a component basis, facility expenses, base lease operating expenses, and hurricane remediation costs net of insurance claims, increased $9.6 million, $5.3 million and $5.0 million, respectively, while insurance premiums and workover costs decreased $4.6 million and $2.1 million, respectively. The increase in facility expenses is primarily attributable to work performed on the tendon tension monitoring system and mechanical repairs at our Matterhorn platform, the pipeline repairs at our Ship Shoal 300 field to remove paraffin and other work on newly acquired deepwater properties. The increase in base lease operating expenses is primarily attributable to the properties purchased from Shell in 2010, the acquisition of the Permian Basin Properties in 2011 and the final settlement adjustments related to properties sold in 2009 that served to reduce expenses in 2010. Hurricane remediation costs net of insurance claims increased due to the return of insurance reimbursements previously received by us related to prepayments based on preliminary estimates, reversal of previously recorded hurricane remediation accruals in the first quarter of 2010, and reductions in claims submitted for reimbursement. The decrease in insurance resulted primarily from lower premiums on our insurance policies covering well control and hurricane damage. Workover costs decreased due to numerous projects undertaken in 2010 that did not reoccur in 2011.

*Production taxes.* Production taxes increased to $1.1 million for the first six months of 2011 compared to $0.5 million in the prior year due to the acquisition of the Permian Basin Properties and are currently not a large component of our operating costs. Most of our production is from federal waters where there are no production taxes while onshore operations are subject to production taxes.

*Gathering and transportation costs.* Gathering and transportation costs were basically flat for the first six months compared to the prior year.

*Depreciation, depletion, amortization and accretion.* DD&A, including accretion for ARO, decreased to $3.31 per Mcfe for the first six months of 2011 from $3.40 per Mcfe in the first six months of 2010. On a nominal basis, DD&A increased to $157.5 million for the first six months of 2011 from $145.2 million in the first six months of 2010. DD&A on a per Mcfe basis decreased due to an increase in proved reserves while DD&A on a nominal basis increased due to higher production volumes.

*General and administrative expenses.* General and administrative expenses increased to $36.1 million for the first six months of 2011 from $24.8 million for the same period in 2010, primarily due to higher incentive compensation as a result of improved financial and operational performance, higher salaries, surety premiums, fees paid to Shell for administrative services attributable to the properties purchased from Shell, reduced overhead charges billed to joint interest operators and service fee income received in 2010 attributable to a property divestiture. On a per Mcfe basis, G&A was $0.76 per Mcfe for the first six months of 2011, compared to $0.58 per Mcfe for the same period in 2010.

*Derivative (gain)/loss.* For the first six months of 2011, our derivative loss of $6.5 million related entirely to a change in the fair value of our commodity derivatives as a result of the changes in crude oil prices. For the first six months of 2010, our derivative gain of $13.3 million related to a gain from our commodity derivatives of $13.6 million and a loss of $0.3 million related to our interest rate swap. For additional details about our derivatives, refer to Item 1 *Financial Statements Note 5 Derivative Financial Instruments* under Part I, Item 1 of this Form 10-Q.

*Interest expense*. Interest expense incurred increased to $22.2 million for the first six months of 2011 from $21.8 million for the same period in 2010 primarily as a result of increased borrowings related to the funding of the acquisition of the Permian Basin Properties. During the first six months of 2011 and 2010, $3.5 million and $2.7 million, respectively, of interest was capitalized to unevaluated oil and natural gas properties with the increase attributable to the acquisition of the Permian Basin Properties.

*Loss on extinguishment of debt.* The loss on extinguishment of debt of $20.7 million was attributable primarily due to the repurchase premium related to the tender offer for the 8.25% Senior Notes. This offer was made concurrently with, and funded with a portion of the proceeds from, the issuance of the 8.5% Senior Notes. The consent payment, unamortized debt issuance costs and other related expenses totaled $20.0 million. In addition, the previous revolving bank credit facility was replaced resulting in the write off of unamortized debt issuance costs of $0.7 million. For additional information about our long-term debt and revolving bank credit facility, refer to *Financial Statements Note 6 Long-Term Debt* under Part I, Item 1 of this Form 10-Q.

*Income tax expense.* Income tax expense increased to $40.0 million for the first six months of 2011 compared to $7.1 million for the same period of 2010. Our effective tax rate for the first six months of 2011 was 35.2%, which approximates the statutory rate. Our effective tax rate for the first six months of 2010 was approximately 9.2% and primarily reflects a reduction in our valuation allowance that was recorded in prior years.

**Liquidity and Capital Resources**

Our primary liquidity needs are to fund capital expenditures and strategic property acquisitions to allow us to replace our oil and natural gas reserves, repay outstanding borrowings and make related interest payments. We have funded our capital expenditures, including acquisitions, with cash on hand, cash provided by operations, securities offerings and bank borrowings. These sources of liquidity have historically been sufficient to fund our ongoing cash requirements.

*Cash flow and working capital.* Net cash provided by operating activities for the first six months of 2011 was $229.8 million, compared to $244.3 million for the first six months of 2010. The decrease is primarily due to income tax payments in 2011 of $19.1 million compared to tax refunds of $99.8 million received in the 2010 period. Otherwise cash flow provided by operating activities is higher due to a significant improvement in operations attributable to higher prices and higher production. Our combined average realized sales price was 19.4% higher than the comparable 2010 period and our combined total production of oil, NGLs and natural gas during the first six months of 2011 was approximately 11.0% higher than the comparable 2010 period.

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Net cash used in investing activities totaled $483.0 million and $205.1 million during the first six months of 2011 and 2010, respectively, which primarily represents our investments in oil and natural gas properties. Major acquisitions consisted of the cash portion of the Permian Basin Properties purchased in 2011 ($397.0 million) and the offshore properties purchased from Total in 2010 ($116.6 million). In addition, investments in other oil and natural gas properties and equipment were $85.8 million in the first six months of 2011 compared to $89.7 million in the first six months of 2010. There were no proceeds from sales of assets in the first six months of 2011 and proceeds from asset sales were $1.3 million for the first six months of 2010.

Net cash provided by financing activities was $233.2 million during the first six months of 2011. Funds were provided through net borrowings on the revolving bank credit facility of $75 million and issuance of $600 million of 8.5% Senior Notes; partially offset by the purchase of $406.2 million of the 8.25% Senior Notes, repurchase premium and debt issuance costs of $29.7 million and the payment of dividends of $6.0 million. See *Financial Statements Note 6 Long-Term Debt* under Part I, Item 1 of this Form 10-Q for additional information on the Senior Notes transactions. Net cash used in financing activities during the first six months of 2010 was $4.5 million which reflects dividend payments during the period.

At June 30, 2011, we had a cash balance of $8.7 million and $412.0 million of undrawn capacity available under the new revolving bank credit facility.

*Credit agreement and long-term debt.* At June 30, 2011, there were $75 million borrowings outstanding under our revolving bank credit facility compared to zero at December 31, 2010. At June 30, there was $600 million of our 8.5% Senior Notes outstanding and $43.9 million of our 8.25% Senior Notes outstanding and at December 31, 2011 there was $450 million outstanding of our 8.25% Senior Notes. We believe that cash provided by operations, borrowings available under our revolving bank credit facility and other external sources of liquidity should be sufficient to fund our ongoing cash requirements.

On May 5, 2011, we entered into the Credit Agreement which provides a revolving bank credit facility with an initial borrowing base of $525 million collateralized by our oil and natural gas properties. The Credit Agreement terminates on May 5, 2015 and replaces the Prior Credit Agreement, which would have expired July 23, 2012. Fees and transactions costs related to the Credit agreement were approximately $5.6 million. The terms of the Credit Agreement are substantially similar to the terms of the Prior Credit Agreement. Availability under the Credit Agreement is subject to a semi-annual borrowing base determination set at the discretion of our lenders. The amount of the borrowing base is calculated by our lenders based on their evaluation of our proved reserves and their own internal criteria. Any determination by our lenders to change our borrowing base will result in a similar change in the availability under our revolving bank credit facility. As of June 30, 2011, our borrowing base was $487.5 million as the borrowing base was reduced due to the issuance of the 8.5% Senior Notes. The borrowing base will be increased by $50 million if we close on the acquisition of certain properties owned by Shell by September 2, 2011.

The Credit Agreement contains various financial covenants calculated as of the last day of each fiscal quarter, including a minimum current ratio and a maximum leverage ratio, as defined in the Credit Agreement. We were in compliance with all applicable covenants of the Credit Agreement as of June 30, 2011. During the first six months of 2011, borrowings outstanding on the revolving bank credit facility increased to $300 million to fund the acquisition of the Permian Basin Properties, which also included funding from cash on hand. These borrowings were subsequently reduced to $75 million as of June 30, 2011, by utilizing cash from operations and funds received from the senior note transactions described below. Letters of credit outstanding as of June 30, 2011 were $0.5 million.

On June 10, 2011, we issued $600 million of 8.5% Senior Notes and used a portion of the net proceeds to repurchase $406.2 million of the 8.25% Senior Notes. The net cash provided by these Senior Notes transactions as of June 30, 2011, which includes initial purchaser fees, consent payments and other transactions costs, was $169.7 million. These transactions extended the maturity date of our long-term debt and we used the remaining net proceeds to pay down outstanding borrowings under the revolving bank credit facility. The 8.5% Senior Notes mature on June 15, 2019. Interest is payable semi-annually in arrears on June 15 and December 15 of each year beginning on December 15, 2011. On July 18, 2011, we purchased the remaining $43.9 million of the 8.25% Senior Notes for $45.7 million, representing a redemption premium of 4.125% pursuant to the terms of the 8.25% Senior Notes.

For additional information about our credit agreement and long-term debt, refer to *Financial Statements Note 6 Long-Term Debt* under Part I, Item 1 of this Form 10-Q.

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*Derivatives.* From time to time, we use various derivative instruments to manage our exposure to commodity price risk from sales of oil and natural gas and interest rate risk from floating interest rates on our revolving bank credit facility. As of June 30, 2011, our derivative instruments outstanding consisted of commodity option contracts relating to approximately 0.6 MMBbls and 1.1 MMBbls of our anticipated oil production for the balance of 2011 and the full year of 2012, respectively. For additional details about our derivatives, refer to Item 1 *Financial Statements Note 5 Derivative Financial Instruments* under Part I, Item 1 of this Form 10-Q.

*Hurricane Remediation and Insurance Claims.* During the third quarter of 2008, Hurricane Ike, and to a much lesser extent Hurricane Gustav, caused property damage and disruptions to our exploration and production activities. Our insurance coverage policy limits at the time of Hurricane Ike were $150 million for property damage due to named windstorms (excluding certain damage incurred at our marginal facilities) and $250 million for, among other things, removal of wreckage if mandated by any governmental authority. The policies in effect on the occurrence dates of Hurricanes Ike and Gustav had a retention requirement of $10 million per occurrence. In 2008, we satisfied our $10 million retention requirement for Hurricane Ike in connection with two platforms that were toppled and were deemed total losses. The damage we incurred as a result of Hurricane Gustav was below our retention amount.

We recognize insurance receivables with respect to capital, repair and plugging and abandonment costs as a result of hurricane damage when we deem those to be probable of collection. Our assessment of probability considers the review and approval of such costs by our insurance underwriters adjuster. Claims that have been processed in this manner have customarily been paid on a timely basis.

In the first six months of 2011 and the year 2010, we received cash of $11.9 million and $65.5 million, respectively, from our insurance carrier related to Hurricane Ike claims. We have recorded $6.9 million of insurance receivables as of June 30, 2011 for claims that have been submitted and approved for payment. As of June 30, 2011, we have recorded in ARO an estimate of $65.5 million for additional costs to be incurred related to Hurricane Ike and we estimate that this work will be completed by the end of 2012. We expect to receive reimbursement for a portion of these costs from our insurance carrier once the costs are incurred, claims are processed and payments are approved, but cannot estimate the amount of reimbursement to be received at this time. Should necessary expenditures exceed our insurance coverage for damages incurred as a result of Hurricane Ike, or claims are denied by our insurance carrier for other reasons, we expect that our available cash on hand, cash flow from operations and the availability under our revolving bank credit facility will be sufficient to meet these future cash needs.

For a discussion of our hurricane remediation costs related to lease operating expenses incurred during the first six months of 2011 and 2010, refer to *Financial Statements Note 3 Hurricane Remediation and Insurance Claims* under Part I, Item 1 of this Form 10-Q. Lease operating expenses will be offset in future periods to the extent that these costs incurred are approved for payment under our insurance policies.

We currently carry three layers of insurance coverage for our operating activities in the Gulf of Mexico. The current policy limits for well control and hurricane damage (defined as named windstorm in our policies) are up to $100 million and $120 million, respectively, and the policies are effective until June 1, 2012. We carry an additional $100 million of well control coverage effective until June 1, 2012 on certain wells at our Mahogany, Matterhorn, Virgo, Tahoe and SE Tahoe fields. A retention amount of $5 million for well control events and $37.5 million per hurricane occurrence must be satisfied by us before we are indemnified for losses. Certain properties we have deemed as non-core are not covered for hurricane damage; however, properties representing approximately 96% of our present value of estimated future net revenues discounted at 10% ( PV-10 ) at December 31, 2010 are covered under our insurance policies for hurricane damage. Pollution causing a negative environmental impact is characterized as a covered component of each of the well control and hurricane sections of the policy.

Our general and excess liability policy provides for $250 million of liability coverage for bodily injury and property damage, including liability claims resulting from seepage, pollution or contamination. With respect to the Oil Spill Financial Responsibility ( OSFR ) requirement under the Oil Pollution Act (the OPA ), we are required to evidence $150 million of financial responsibility to the BOEMRE. We qualify to self-insure for $35 million of this amount and the remaining $115 million is covered by our insurance policy. We may only collect proceeds under this OSFR policy after our well control, hurricane damage and excess liability policies have been exhausted.

These policies summarized above have annual terms that expire in May and June of 2012. The premiums for the above policies were $30 million compared to $22 million for the policies that expired in May and June of 2011. Although we have not been informed otherwise, in the future, our insurers may not continue to offer this type and level of coverage to us, or our

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costs may increase substantially as a result of increased premiums and the increased risk of uninsured losses that may have been previously insured, all of which could have a material adverse effect on our financial condition and results of operations. We are also exposed to the possibility that in the future we will be unable to buy insurance at any price or that if we do have a claim, the insurance companies will not pay our claim. However, we are not aware of any financial issues related to any of our insurance underwriters that would affect their ability to pay claims. We do not carry business interruption insurance.

*Capital expenditures.* The level of our investment in oil and natural gas properties changes from time to time depending on numerous factors, including the prices of oil and natural gas, acquisition opportunities, and the results of our exploration and development activities. The following table presents our capital expenditures for acquisitions, exploration, development and other leasehold costs:

| | Six Months Ended June 30, | |
|---|---|---|
| | **2011** | **2010** |
| | (in thousands) | |
| Acquisition of Opal properties (Permian Basin) | $ 396,976 | $ |
| Acquisition of Total properties | | 116,589 |
| Exploration (1) | 20,891 | 48,563 |
| Development (1) | 52,229 | 25,790 |
| Seismic, capitalized interest, other leasehold costs | 12,681 | 15,352 |
| Acquisitions and investments in oil and gas property/equipment | $ 482,777 | $ 206,294 |

(1) Reported by geography in the subsequent table.

The following table presents our exploration and development capital expenditures by geography:

| | Six Months Ended June 30, | |
|---|---|---|
| | **2011** | **2010** |
| | (in thousands) | |
| Conventional shelf | $ 52,387 | $ 67,281 |
| Deepwater | 2,195 | 4,806 |
| Deep shelf | 31 | 2,266 |
| Onshore | 18,507 | |
| Exploration and development capital expenditures | $ 73,120 | $ 74,353 |

Our 2011 capital expenditures were financed by cash flow from operating activities, cash on hand and additional borrowings. Our 2010 capital expenditures were financed by cash flow from operating activities and cash on hand.

During the first six months of 2011, we participated in the drilling of ten onshore wells and three offshore wells, all of which were successful. One onshore well was an exploration well in south Texas and the other nine onshore wells were development wells in the Permian Basin of West Texas. All of the offshore wells were on the conventional shelf with one being an exploration well and the other two being development wells.

During the first six months of 2010, we participated in the drilling of five offshore wells, four of which were successful. Of the successful wells, all four were on the conventional shelf with three being exploration wells and one a development well.

Our total capital expenditure budget for 2011 is $310 million, which excludes acquisitions. Although there has been considerable shuffling of wells and focus areas since the original budget was prepared, we believe that the $310 million continues to be a reasonable estimate of our capital expenditures, excluding acquisitions, for 2011. The budget includes amounts for drilling and evaluation of wells, well completions, facilities capital, recompletions, seismic and leasehold items. Our 2011 capital budget is subject to change as conditions warrant and our budget is sufficiently flexible such that most any change can be made without incurring any contractor breakage or commitment fees.

Capital expenditures associated with development activities for the Permian Basin Properties acquired in May 2011 from the closing date of May 11, 2011 to December 31, 2011 are currently estimated between $40 million and $50 million and are included in the total annual capital expenditure budget described above. For additional information on this acquisition, please see *Financial Statements - Note 2 Acquisitions* under Part I, Item 1 of this Form 10-Q.

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We intend to continue to pursue acquisitions and joint venture opportunities during 2011 should attractive opportunities arise. We are actively evaluating several other opportunities and expect to complement our drilling and exploitation projects with acquisitions providing acceptable rates of return. We anticipate funding our 2011 capital budget and acquisitions with internally generated cash flow, cash on hand, borrowings under our revolving bank credit facility, issuance of our 8.5% Senior Notes and additional long-term debt as needed.

*Income taxes*. During the six months ended June 30, 2011, we made tax payments of $19.1 million which relate to the 2010 tax year. For the six months ended June 30, 2010, we received refunds of approximately $99.8 million. For the year 2011, we expect substantially all of our income tax will be deferred and only minimal payments are expected primarily related to alternative minimum tax.

*Dividends*. During the first six months of 2011 and 2010, we paid regular cash dividends of $0.04 and $0.03 per common share per quarter, respectively. On August 3, 2011, our board of directors declared a cash dividend of $0.04 per common share, payable on September 12, 2011 to shareholders of record on August 22, 2011.

*Contractual obligations*. Major changes in contractual obligations from those disclosed in Item 7 of our Annual Report on Form 10-K for the year ended December 31, 2010 are as follows: 1) asset retirement obligations as disclosed in *Financial Statements - Note 4 Asset Retirement Obligations* under Part I, Item 1 of this Form 10-Q; 2) additions of principal and interest related to our 8.5% Senior Notes and reductions of principal and interest related to our 8.25% Senior Notes principal as disclosed in *Financial Statements - Note 6 Long-Term Debt* under Part I, Item 1 of this Form 10-Q; 3) drilling rig contracts with terms of six months or less have additional commitments of $27.6 million subsequent to June 30, 2010; and 4) changes to derivative contracts as disclosed in *Financial Statements - Note 5 Derivative Financial Instruments* under Part I, Item 1 of this Form 10-Q.

**Critical Accounting Policies**

Our significant accounting policies are summarized in Note 1 of Notes to Consolidated Financial Statements included in our Annual Report on Form 10-K for the year ended December 31, 2010. Also refer to the Notes to Condensed Consolidated Financial Statements included in Part 1, Item 1 of this Form 10-Q.

**Recent Accounting Pronouncements**

None.

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

Information about market risks for the first six months of 2011 did not change materially from the disclosures in Item 7A of our Annual Report on Form 10-K for the year ended December 31, 2010. As such, the information contained herein should be read in conjunction with the related disclosures in our Annual Report on Form 10-K for the year ended December 31, 2010.

***Commodity Price Risk***. Our revenues, profitability and future rate of growth substantially depend upon market prices of oil and natural gas, which fluctuate widely. In the past, oil and natural gas price declines and volatility have negatively affected our revenues, net cash provided by operating activities and profitability. We have entered into a limited number of commodity option contracts to help manage our exposure to commodity price risk from sales of oil during the fiscal years ending December 31, 2011 and 2012. As of June 30, 2011 our derivative instruments outstanding consisted of commodity option contracts relating to approximately 0.6 MMBbls and 1.1 MMBbls of our anticipated production for the balance of 2011 and year 2012, respectively. While these contracts are intended to reduce the effects of volatile oil prices, they may also limit future income if oil prices were to rise substantially over the price established by the hedge. Currently, we do not have any commodity option contracts for natural gas. We do not enter into derivative instruments for speculative trading purposes. For additional details about our commodity derivatives, refer to Item 1 *Financial Statements - Note 5 Derivative Financial Instruments* under Part I, Item 1 of this Form 10-Q.

***Interest Rate Risk.*** We currently do not have any derivative instruments related to interest rates. As of June 30, 2011, we had $75 million of floating rate debt outstanding. Borrowings on our revolving bank credit facility are subject to interest rate risk.

**Item 4. Controls and Procedures**

We have established disclosure controls and procedures designed to ensure that material information required to be disclosed in our reports filed under the Exchange Act is recorded, processed, summarized and reported within the time periods specified by the SEC and that any material information relating to us is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosures. In designing and evaluating our disclosure controls and procedures, our management recognizes that controls and procedures, no matter how well designed and operated, can provide only reasonable assurance of achieving desired control objectives. In reaching a reasonable level of assurance, our management necessarily was required to apply its judgment in evaluating the cost-benefit relationship of possible controls and procedures.

As required by Exchange Act Rule 13a-15(b), we performed an evaluation, under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) as of the end of the period covered by this report. Based on that evaluation, our Chief Executive Officer and Chief Financial Officer have each concluded that as of June 30, 2011 our disclosure controls and procedures are effective to ensure that information we are required to disclose in reports filed or submitted under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC s rules and forms, and that our controls and procedures are designed to ensure that information required to be disclosed by us in such reports is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

During the quarter ended June 30, 2011, there was no change in our internal control over financial reporting that materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

## PART II OTHER INFORMATION

**Item 1. Legal Proceedings**

None.

**Item 1A. Risk Factors**

Carefully consider the risk factors set forth below, as well as the risk factors included under the caption Risk Factors under Part I, Item 1A in the Company s Annual Report on Form 10-K for the year ended December 31, 2010, together with all of the other information included in this document, in the Company s Annual Report on Form 10-K and in the Company s other public filings, press releases and discussions with Company management.

***Federal and state legislation and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays.***

Hydraulic fracturing is an important and common practice that is used to stimulate production of hydrocarbons from tight formations. We utilize hydraulic fracturing techniques in connection with developing our recently acquired Permian Basin Properties and other properties. The process involves the injection of water, sand and small amounts of chemicals under pressure into the formation to fracture the surrounding rock and stimulate production. The process is typically regulated by state oil and gas commissions. The federal Environmental Protection Agency ( EPA ), however, recently asserted federal regulatory authority over certain hydraulic fracturing activities involving diesel fuel under the federal Safe Drinking Water Act s (the SDWA ) Underground Injection Control Program and has begun the process of drafting guidance documents on regulating requirements for companies that plan to conduct hydraulic fracturing using diesel fuel. In addition, a number of federal agencies are analyzing a variety of environmental issues associated with hydraulic fracturing. The EPA has commenced a study of the potential environmental effects of hydraulic fracturing activities, with initial results expected to be available by late 2012 and final results by 2014. A committee of the United States House of Representatives also has conducted an investigation of hydraulic fracturing practices. These studies, depending on their results, could spur initiatives to regulate hydraulic fracturing under the SDWA or otherwise. Legislation also has been introduced before Congress to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the fracturing process. In addition, some states and local governments have adopted, and other states and local governments are considering

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adopting, regulations that could impose more stringent permitting, disclosure and well construction requirements on hydraulic fracturing operations, including states in which we operate. For example, on June 17, 2011, Texas signed into law a bill that requires the disclosure of information regarding the substances used in the hydraulic fracturing process to the Railroad Commission of Texas (the entity that regulates oil and natural gas production in Texas) and the public. The disclosure of information regarding the constituents of hydraulic fracturing fluids could make it easier for third parties opposing the hydraulic fracturing process to initiate legal proceedings based upon allegations that specific chemicals used in the fracturing process could adversely affect the environment, including groundwater, soil or surface water. In addition, disclosure of proprietary chemical formulas or disclosure of any chemicals used in such formulas to the public could diminish the value of those formulas and could result in competitive harm to us. If new laws or regulations that significantly restrict hydraulic fracturing are adopted, such laws could make it more difficult or costly for us to perform fracturing to stimulate production from tight formations. In addition, if hydraulic fracturing becomes regulated at the federal level as a result of federal legislation or regulatory initiatives by the EPA, our fracturing activities could become subject to additional permitting requirements, and also to attendant permitting delays and potential increases in costs. Restrictions on hydraulic fracturing could also reduce the amount of oil and natural gas that we are ultimately able to produce from our reserves.

***Recently Proposed Rules Regulating Air Emissions from Oil and Gas Operations Could Cause Us to Incur Increased Capital Expenditures and Operating Costs***

On July 28, 2011, the Environmental Protection Agency ( EPA ) proposed rules that would establish new air emission controls for oil and natural gas production and natural gas processing operations. Specifically, EPA s proposed rule package includes New Source Performance Standards to address emissions of sulfur dioxide and volatile organic compounds ( VOCs ) and a separate set of emission standards to address hazardous air pollutants frequently associated with oil and natural gas production and processing activities. EPA s proposal would require the reduction of VOC emissions from oil and natural gas production facilities by mandating the use of green completions for hydraulic fracturing, which requires the operator to recover rather than vent the gas and natural gas liquids that come to the surface during completion of the fracturing process. The proposed rules also would establish specific requirements regarding emissions from compressors, dehydrators, storage tanks, and other production equipment. In addition, the rules would establish new leak detection requirements for natural gas processing plants. EPA will receive public comment and hold hearings regarding the proposed rules and must take final action on them by February 28, 2012. If finalized, these rules could require a number of modifications to our operations including the installation of new equipment. Compliance with such rules could result in significant costs, including increased capital expenditures and operating costs, and could adversely impact our business.

**Item 5. Other Information - Submission of Matters to a Vote of Security Holders**

As disclosed in the Company s Form 10-Q for the quarter ended March 31, 2011, the shareholders non-binding advisory vote selected three-years as the frequency of future non-binding advisory votes to approve the compensation of the Company s executives. On August 3, 2011, the Board approved a resolution to use the three-year frequency for future non-binding advisory votes to approve the compensation of the Company s executives until the next required vote on the frequency of shareholder votes on the compensation of the Company s executives.

**Item 6. Exhibits**

The exhibits to this report are listed in the Exhibit Index.

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**SIGNATURE**

Pursuant to the requirements of Section 13 or 15(d) of the Exchange Act, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, on August 4, 2011.

**W&T OFFSHORE, INC.**

By: /s/ John D. Gibbons

**John D. Gibbons**
**Senior Vice President, Chief Financial Officer and Chief Accounting Officer, duly authorized to sign on behalf of the registrant**

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**EXHIBIT INDEX**

| Exhibit Number | Description |
|---|---|
| 2.1 | Purchase and Sale Agreement between Opal Resources, LLC and W&T Offshore, Inc. (Incorporated by reference to Exhibit 2.1 of the Company s Current Report on Form 8-K, filed May 13, 2011) |
| 3.1 | Amended and Restated Articles of Incorporation of W&T Offshore, Inc. (Incorporated by reference to Exhibit 3.1 of the Company s Current Report on Form 8-K, filed February 24, 2006) |
| 3.2 | Amended and Restated Bylaws of W&T Offshore, Inc. (Incorporated by reference to Exhibit 3.2 of the Company s Registration Statement on Form S-1, filed May 3, 2004 (File No. 333-115103)) |
| 4.1 | First Supplemental Indenture, dated as of June 10, 2011, by and among W&T Offshore, Inc., the Guarantors named therein and Wells Fargo Bank, National Association, as trustee. (Incorporated by reference to Exhibit 4.1 of the Company s Current Report on Form 8-K, filed June 16, 2011) |
| 4.2 | Indenture, dated as of June 10, 2011, by and among W&T Offshore, Inc., the Guarantors named therein and Wells Fargo Bank, National Association, as trustee. (Incorporated by reference to Exhibit 4.1 of the Company s Current Report on Form 8-K, filed June 16, 2011) |
| 4.3 | Form of 8.5% Senior Notes due 2019 (included in Exhibit 4.2) |
| 4.4 | Registration Rights Agreement, dated June 10, 2011, by and among W&T Offshore, Inc., the Guarantors named therein and Morgan Stanley & Co. LLC, as representative of the Initial Purchasers. (Incorporated by reference to Exhibit 4.1 of the Company s Current Report on Form 8-K, filed June 16, 2011) |
| 10.1 | Fourth Amended and Restated Credit Agreement, dated May 5, 2011, by and among W&T Offshore, Inc., Toronto Dominion (Texas) LLC, as agent and the various agents and lenders party thereto. (Incorporated by reference to Exhibit 10.1 of the Company s Current Report on Form 8-K, filed May 6, 2011) |
| 31.1* | Section 302 Certification of Chief Executive Officer. |
| 31.2* | Section 302 Certification of Chief Financial Officer. |
| 32.1* | Section 906 Certification of Chief Executive Officer and Chief Financial Officer. |
| 101.INS* | XBRL Instance Document |
| 101.SCH* | XBRL Schema Document |
| 101.CAL* | XBRL Calculation Linkbase Document |
| 101.DEF* | XBRL Definition Linkbase Document |
| 101.LAB* | XBRL Label Linkbase Document |
| 101.PRE* | XBRL Presentation Linkbase Document |

* Filed or furnished herewith.