Rosetta Resources Inc.
Form 10-K
March 16, 2007

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

# FORM 10-K

x **Annual Report Pursuant To Section 13 or 15(d) of The Securities Exchange Act of 1934**

**For The Fiscal Year Ended December 31, 2006**

**OR**

¨ **Transition Report Pursuant To Section 13 Or 15(d) of The Securities Exchange Act of 1934**

**Commission File Number: 000-51801**

**ROSETTA RESOURCES INC.**
**(Exact name of registrant as specified in its charter)**

| | |
|---|---|
| **Delaware** | **43-2083519** |
| **(State or other jurisdiction of incorporation or organization)** | **(I.R.S. Employer Identification No.)** |
| **717 Texas, Suite 2800, Houston, TX** | **77002** |
| **(Address of principal executive offices)** | **(Zip Code)** |

Registrant's telephone number, including area code: **(713) 335-4000**

Securities Registered Pursuant to Section 12(b) of the Act:

| | |
|---|---|
| **Common Stock, $.001 Par Value** | **The Nasdaq Stock Market LLC** |
| (Title of Class) | (Name of Exchange on which registered) |

Securities Listed Pursuant to Section 12 (g) of the Act:
**None**

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act of 1933. Yes ¨ Nox

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934. Yes ¨ Nox

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

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of the registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. x

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer or a non-accelerated filer. See definition of "accelerated filer and large accelerated filer" in Rule 12b-2 of the Securities Exchange Act of 1934. Large accelerated filer ¨ Accelerated filer ¨ Non-Accelerated filer x

Indicate by check mark whether the registrant is a shell company (as defined by Rule 12b-2 of the Securities Exchange Act of 1934). Yes ¨ No x

The aggregate market value of the voting and non-voting common equity held by non-affiliates of the registrant as of June 30, 2006 was approximately $831 million based on the closing price of $16.62 per share on the Nasdaq Global Select Market.

The number of shares of the registrant's Common Stock, $.001 par value per share outstanding as of March 5, 2007 was 50,753,951.

**Documents Incorporated By Reference**

Information required by Part III will either be included in Rosetta Resources Inc.'s definitive proxy statement filed with the Securities and Exchange Commission or filed as an amendment to this Form 10-K no later than 120 days after the end of the Company's fiscal year, to the extent required by the Securities Exchange Act of 1934, as amended.

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Cautionary Note

This Annual Report contains forward-looking statements of our management regarding factors that we believe may affect our performance in the future. Such statements typically are identified by terms expressing our future expectations or projections of revenues, earnings, earnings per share, cash flow, market share, capital expenditures, effects of operating initiatives, gross profit margin, debt levels, interest costs, tax benefits and other financial items. All forward-looking statements, although made in good faith, are based on assumptions about future events and are, therefore, inherently uncertain; and actual results may differ materially from those expected or projected. Important factors that may cause our actual results to differ materially from expectations or projections include those described under the heading “Forward-Looking Statements” in Item 7. Forward-looking statements speak only as of the date of this report, and we undertake no obligation to update or revise such statements to reflect new circumstances or unanticipated events as they occur.

For a glossary of oil and natural gas terms, see page 97.

## Part I

### Item 1. Business

### General

Rosetta Resources Inc. (together with our consolidated subsidiaries, the “Company”) was formed in June 2005 to acquire Calpine Natural Gas L.P. the domestic oil and natural gas business formerly owned by Calpine Corporation and affiliates (“Calpine”). The Company (“Successor”) acquired Calpine Natural Gas L.P. (“Predecessor”) in July 2005 (hereinafter, the “Acquisition”) and together with all subsequently acquired oil and gas properties is engaged in oil and natural gas exploration, development, production and acquisition activities in the United States and operates in one business segment. Our operations are primarily concentrated in the Sacramento Basin of California, the Lobo and Perdido Trends in South Texas, the State Waters of Texas, the Gulf of Mexico and the Rocky Mountains. The Company has grown its existing property base through exploitation of its leasehold acreage and by: purchasing new undeveloped leases; acquiring oil and gas producing properties from third parties; and acquiring drilling prospects with third parties where the Company earns an ownership interest in new third party properties or otherwise participates in exploration.

Pursuant to the Acquisition, we entered into several operative contracts with Calpine, including a purchase and sale agreement (together with the interrelated agreements concurrently executed on or about July 7, 2005, are hereinafter, collectively, the “Purchase Agreement”) under which we have indemnification rights and obligations with respect to Calpine. Currently, Calpine markets our oil and gas under a marketing services agreement whose term runs through June 30, 2007. We also sell a significant portion of our gas to Calpine pursuant to certain gas purchase and sales contracts, all of which were part of the Acquisition documents.

In October 1999, Calpine purchased Sheridan Energy, Inc. (“Sheridan”), a natural gas exploration and production company operating in northern California and the Gulf Coast region. Sheridan, renamed Calpine Natural Gas Company, provided the initial management team an operational infrastructure to evaluate and acquire oil and natural gas properties for Calpine. In December 1999, Calpine purchased Vintage Petroleum, Inc.’s interest in the Rio Vista Gas Unit and related areas, representing primarily natural gas reserves located in the Sacramento Basin in northern California. In October 2001, Calpine Natural Gas Company completed the acquisition of 100% of the voting stock of Michael Petroleum Corporation, a natural gas exploration and production company with operations in South Texas. Calpine Natural Gas Company was merged into Calpine in April 2002, and Calpine Natural Gas L.P. was subsequently established. In September 2004, Calpine and Calpine Natural Gas L.P. sold their natural gas reserves in the New Mexico San Juan Basin and Colorado Piceance Basin and such properties have been reflected as discontinued operations for all periods presented herein. Several members of the Calpine management team, who were responsible for operating Calpine’s oil and natural gas business, joined the Company concurrently with the Acquisition.

**Our Strengths**

We believe our historical success is, and future performance will be, directly related to the following combination of strengths:

***High Quality, Diversified Asset Base.*** We own a geographically diversified asset base comprised of long-lived reserves along with shorter-lived, higher return reserves. Approximately 96% of our reserves are natural gas and almost all of our assets are located in the Sacramento Basin of California, South Texas, the Gulf of Mexico and the Rocky Mountains. We believe this geographic and production profile diversity will enhance the stability of our cash flows while providing us with a large number of development and exploration opportunities, as well as support for additional acquisitions.

***Development and Exploration Drilling Inventory.*** We have identified over 500 drillable, low to moderate risk opportunities providing us with multiple years of drilling inventory, and we expect to drill approximately 190 of these locations during 2007. Approximately 20% of these locations are classified as proved undeveloped. We also have a large and diversified portfolio of what we designate as development and exploration prospects. Our capital expenditure budget is approximately $250 million for 2007. We will manage our exploratory risks and expenditures by selectively reducing our capital exposure in certain high risk projects by partnering with others in our industry.

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***Operational Control.*** We operate approximately 90% of our estimated proved reserves, which allows us to more effectively manage expenses and control the timing of capital allocation of our development and exploration activities.

***Experienced Management Team.*** Our executive management team has an average of over 30 years of experience in the oil and natural gas industry as well as strong technological backgrounds.

***Proven Technical and Land Personnel with Access to Technological Resources.*** Our technical staff of 28 includes geologists, geophysicists, landmen, engineers and technicians with an average of over 20 years of relevant technical experience. Our staff has a proven record of analyzing complex structural and stratigraphic plays using 3-D geophysical expertise, producing and optimizing low pressure natural gas reservoirs, detecting low contrast, low permeability pay opportunities, drilling, completing and fracing of deep tight natural gas reservoirs operating in the Gulf of Mexico and managing horizontal drilling and coalbed methane operations. These core competencies helped us to achieve a drilling success rate of 85% for the year ended December 31, 2006 and has helped maximize recovery from our reservoirs. Our definition of drilling success is a well that produces hydrocarbons at sufficient rates to allow us to recover, at a minimum, our capital investment and operating costs.

## Our Strategy

Our strategy is to increase stockholder value by profitably increasing our reserves, production, cash flow and earnings using a balanced program of (1) developing existing properties, (2) exploring undeveloped properties, (3) completing strategic acquisitions (4) maintaining financial flexibility (5) striving to be a low cost producer, and (6) maintaining financial flexibility. We will seek to accomplish these goals while working to protect shareholder interests by conserving natural resources, monitoring emerging trends, minimizing liabilities through an aggressive approach to governmental compliance, respecting the dignity of human life, and protecting the environment. The following are key elements of our strategy:

***Further Development to Existing Properties.*** We intend to further develop the significant remaining upside potential of our properties by working over existing wells, drilling in-fill locations, drilling step-out wells to expand known field outlines, recomplete to logged behind pipe pays and lowering field line pressures through compression for additional reserve recovery.

***Exploration Growth.*** We intend to focus on niche areas in which we have technological and operational advantages. This growth will come from higher-risk, higher-impact opportunities in the Gulf of Mexico, Texas and Louisiana State Waters, in deep horizons in the Sacramento Basin, and from lower-risk, longer-lived opportunities in the shallow Sacramento Basin, the Lobo and Perdido Sand Trends in South Texas, Niobrara chalk in the DJ Basin and coalbed methane in the San Juan Basin. While the majority of our prospects will be internally generated, we will, from time to time, participate in third-party drilling opportunities.

***Acquisition Growth.*** We continually review opportunities to acquire producing properties, undeveloped acreage and drilling prospects. We focus on opportunities where we believe our reservoir management and operational expertise will enhance the value and performance of acquired properties. Acquisition targets will generally be in and around our major producing and activity areas. We will also use our minor producing field ownerships as islands of control and knowledge to make strategic acquisitions. Historically, our management team has demonstrated success in oil and gas acquisitions and has developed a significant oil and gas knowledge base in fields throughout the United States.

***Maintain Technological Expertise.*** We intend to maintain the technological expertise that helped us achieve a drilling success rate of 85% for the year ended December 31, 2006, and helped us maximize field recoveries. We will use advanced geological and geophysical technologies, detailed petrophysical analyses, state-of-the-art reservoir engineering and sophisticated completion and stimulation techniques to grow our reserves and production.

***Endeavor to be a Low Cost Producer.*** We will strive to minimize our operating costs by concentrating our assets within geographic areas where we can capture operating efficiencies. This is particularly true in the Sacramento Basin and South Texas where we are a dominant producer in each region.

***Maintain Financial Flexibility.*** We intend to optimize unused borrowing capacity under our revolving line of credit by periodically refinancing our bank debt in the capital markets when conditions are favorable. As of December 31, 2006, we had $159.0 million available for borrowing under our revolving line of credit. Additionally, we expect internally generated cash flow to provide additional financial flexibility, allowing us to pursue our business strategy. We intend to actively manage our exposure to commodity price risk in the marketing of our oil and natural gas production. As part of this strategy and in connection with our credit facilities, we entered into natural gas fixed-price swaps and costless collar transactions for a significant portion of our expected production through 2009. We may enter into other agreements, including fixed price, forward price, physical purchase and sales, futures, financial swaps, option and put option contracts.

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**Calpine Bankruptcy**

On December 20, 2005 Calpine and certain of its subsidiaries filed for protection under federal bankruptcy laws in the United States Bankruptcy Court of the Southern District of New York (the “Bankruptcy Court”). The filing raises certain concerns regarding aspects of our relationship with Calpine which we will continue to closely monitor as the Calpine bankruptcy proceeds. See Item 3. Legal Proceedings for further information regarding the Calpine bankruptcy.

**Our Operating Areas**

We own producing and non-producing oil and natural gas properties in the Sacramento Basin of California, the Lobo and Perdido Trends in South Texas, the State Waters of Texas, the Gulf of Mexico, the Rocky Mountains and other properties located in various geographical areas in the United States. In each area we are pursuing geological objectives and projects that are consistent with our technical expertise in order to provide the highest potential economic returns. For the year ended December 31, 2006, we have drilled 142 gross and 120 net wells, of which 85% found commercial quantities of production. The following is a summary of our major operating areas in which we discuss their various characteristics. With respect to acreage information in this report, we have included acreage relating to properties for which legal title was not given to us by Calpine on the original date of Acquisition because consents to transfer, which the parties believed at that time were required, had not been obtained as of July 7, 2005. See Item 3. Legal Proceedings for further information regarding the Calpine bankruptcy.

***California-Sacramento Basin***

*Rio Vista Field and Surrounding Area.* The Rio Vista Gas Unit and a significant portion of the deep rights below the Rio Vista Gas Unit, together constitute the greater Rio Vista Field, is the largest onshore natural gas field in California and one of the 15 largest natural gas fields in the United States. The field has produced a cumulative 3.6 Tcfe of natural gas reserves to date since its discovery in 1936. We currently produce from or have behind-pipe reserves in over 16 different zones at depths ranging from 2,500 feet to 9,300 feet in the field. The natural gas field trap is a faulted, downthrown rollover anticline, elongated to the northwest. The current productive area is approximately ten miles long and eight miles wide. A majority of the reservoirs are depletion driven with long production histories. For the twelve months ended December 31, 2006, the average net daily production in the Sacramento Basin was approximately 31 MMcfe from 142 producing wells. As of December 31, 2006, we owned approximately 77,000 net acres in the Rio Vista Field and surrounding Sacramento Basin areas. We are one of the largest producers and leaseholders in the basin. Our acreage in the basin holds significant low-risk, low-cost upside potential in 117 currently shut-in or idle wells, and over 110 drillable locations, and numerous workover and recompletion opportunities. Additional reserve potential exists in gathering system optimization projects, numerous fracture stimulation opportunities in lower permeability, low contrast pays, and deeper gas bearing sands.

We drilled 19 successful wells in and around the Rio Vista field in 2006. Six wells were drilled in the southern portion of the field in extending pays in three reservoirs: Upper Capay, Lower Capay and Martinez. A 12-square mile 3-D program was shot over the Bradford Island area of the field. This area of the field previously has never been covered by seismic data.

*Sacramento Valley Extension.* We believe our existing land position and financial strength will give us the ability to continue expanding our Sacramento Basin operations. The Sacramento Valley Extension Project is an extension of work and study done in the redevelopment of the Rio Vista Field and non-operated drilling in nearby reservoirs. Numerous plays are being evaluated, including Mokelumme gorge traps and McCormick fault traps, deeper Winters traps, and shallow Emigh/Capay truncation traps on the east side of the Sacramento Basin. Low contrast and low resistivity pays in the Emigh, Capay, Hamilton and Martinez formations are being pursued for under-exploited and unrecognized potential. We have approximately 581 square miles of 3-D seismic data and over 2,216 miles of 2-D seismic data in Rio Vista, the extension area, and the greater Sacramento Valley. The area contains 16 prospective producing formations with historically high production rates at shallow to moderate drill depths.

*Other Activities.* We are actively pursuing additional lease acquisitions throughout the Sacramento Basin. In 2006, we added approximately 16,400 acres to our leasehold inventory. We have one rig actively drilling in the field. We will be procuring a deep rig in the summer to drill three deep tests. In all, we plan to drill 30 wells in 2007. There are three completion rigs currently working on Rosetta wells in the Rio Vista area. Other than new well completions, we plan to conduct between 30 and 40 workover, recompletion or reactivation operations on field wells with these rigs during 2007.

***Lobo***

*Lobo Trend.* Discovered in 1973, the Lobo Trend of South Texas is a complex, highly faulted sand that has produced over 7 Tcf of natural gas. The Lobo section produces from tight sands with low permeabilities and high pressures at depths from 7,500 to 10,000 feet. We are a significant producer in the Lobo Trend, with over 65,000 net acres, 320 square miles of 3-D seismic data, approximately 239 active operated wells and interests in approximately 120 non-operated wells. We recently added a new acreage position in the heart of our acreage in the Lobo Trend. For the year ended December 31, 2006, our average net daily production from the Trend was 26.5 MMcfe. Our working interests range from 50% to 100%. We have identified 90 potential drilling locations on our acreage.

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We have two drilling rigs under contract for the drilling program, and we plan to drill 30 wells in the Trend in 2007. We drilled 21 successful wells in 2006.

**Perdido**

*Perdido Sand Trend.* We own a 50% non-operating working interest in approximately 17,500 acres in the Perdido Sand Trend. The Perdido Sands are in isolated fault blocks and are stratigraphically trapped below the Upper Wilcox structures at approximately 8,000 to 9,500 feet. The Perdido Sands are comprised of tight natural gas sands requiring significant fracture stimulation. Horizontal drilling has been very successful in maximizing natural gas recovery. We plan to maintain our current acreage and seismic position and to continue to improve horizontal drilling techniques to lower cost and increase performance. For the twelve months ended December 31, 2006, our average net daily production was 11.4 MMcfe from 28 producing wells. We participated in the drilling of 7 horizontal wells in 2006 with 6 successful. Two of the 7 wells were drilled in 2006 and completed in January 2007. We plan to drill 7 additional wells in 2007.

**Gulf of Mexico**

*Federal Waters.* The Company owns working interests in 11 blocks ranging from 20% to 100%. We have satisfied the regulatory requirement for receiving ministerial approval in all the offshore blocks in the Gulf of Mexico except for four blocks for which we have not received Mineral Management Service's ("MMS") ministerial approvals. In 2006, we acquired ownership interests in another three blocks in the Gulf of Mexico. For the year ended December 31, 2006, our average net daily production from these blocks was 8.3 MMcfe.

During 2006, through our participation in a joint venture, we acquired a 25% non-operated working interest in two OCS blocks, Main Pass Block 118 and Main Pass Block 117. Main Pass Block 118 well No. 1 was drilled, production casing set, successfully tested and is awaiting platform installation. The Block 117 well No. 1 was a dry hole. We acquired a 50% working interest in Main Pass Block 29 and a 25% working interest in Grand Isle Block 72. These wells will be placed on production in 2007. We plan to drill 2 additional wells in the Gulf of Mexico in 2007.

We have entered into an Area of Mutual Interest ("AMI") agreement in which we have the right to participate in up to a 50% working interest in wells within 150 Outer Continental Shelf ("OCS") blocks on the Louisiana offshore shelf. We have obtained MMS leases for another three OCS blocks. We intend to participate in the drilling of at least one to two new prospects each year in these blocks, as well as other blocks in which we may obtain leases.

**State Waters of Texas**

*Galveston Bay.* We continue exploring in the Vicksburg and Frio Trends in Galveston Bay, Texas, specifically pursuing sands that exhibit strong hydrocarbon indicators on 3-D seismic.

In 2006 we participated in the drilling of 5 wells; one of which is on production, two waiting on production facilities and two dry holes. Over average net daily production was 3.1 MMcfe for 2006. We plan to drill 4 additional wells in 2007.

*Sabine Lake.* We own a 50% operated working interest through a joint venture in Sabine Lake, within Texas State Waters of Jefferson County. We are currently drilling a 13,000 foot test well which is one of four expected to be drilled in 2007. We currently hold interest in approximately 2,100 gross acres and have recently acquired an additional interest in approximately 4,800 acres in the same area.

**Other Onshore**

*Live Oak County Prospect.* Through the interpretation of 3-D seismic data, we have identified four structures at approximately 16,500 feet in the Sligo Reef Trend in Live Oak County, Texas. Two of these structures were previously drilled and produced by other operators. One structure has produced 33 Bcfe since 1983 from one well on the south end of our 3-D data coverage, and a second structure on the north end of our data coverage produced 13 Bcfe since 1987, also from one well. We currently have approximately 2,500 net acres under lease and have obtained a partner to join in the drilling of the initial exploratory well to a depth of 17,000 feet. The Exploration Agreement provides for the formation of an AMI covering approximately 22,000 acres for exploration and development purposes. The initial well should commence operations prior to August 31, 2007.

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*Frio, Vicksburg, Yegua and Wilcox Trends.* In Colorado and Wharton Counties, we are pursuing amplitude plays between 3,500 and 7,000 feet in the Frio and Yegua Trends. In the Wilcox Trend, we are pursuing normally pressured structural closures at 10,000 feet and over-pressured closures from 14,000 to 17,500 feet. All of these projects are based on 3-D seismic data. In 2006, we drilled 6 wells and participated in 2 others, with a 50% success rate. We continue to look for additional opportunities in these trends.

We plan to drill 18 additional wells in 2007 in the Other Onshore area.

**Rocky Mountains**

We are active in the DJ and San Juan Basins in the Rocky Mountains.

*DJ Basin, Colorado.* As of December 31, 2006, we had a majority working interest in approximately 95,000 net acres in the Niobrara Chalk play at 2,500 feet. In 2006 we drilled 46 locations, 43 of which were successful. As of December 31, 2006 we have identified approximately 200 additional locations on our existing leases with 70 wells planned for 2007. For the year ended December 31, 2006, our average production from the area was approximately 1 MMcfe/d.

By December 31, 2006, we had acquired 91.1 square miles of 3D seismic data, 61 square miles of which was acquired in 2006. We are using 3-D seismic data as a critical tool in identifying potential drilling opportunities. We drilled 33 successful wells out of 33 attempts in the Republican River 3-D area in 2006. Pipeline and gathering system construction is underway in the Republican River. Additional pipeline, gathering line and water collection pits were permitted and installed in the Kitzmiller area.

*San Juan Basin, New Mexico.* The San Juan Basin is the second most prolific gas basin in North America, according to published articles, with 34 Tcf of production through the end of October 2004, 11.4 Tcf of which comes from the Fruitland Coal CBM (“Coal Bed Methane”). There is Fruitland Coal production from depths of 1,600 feet surrounding our leasehold. We are pursuing this coalbed methane play and had, as of December 31, 2006, a 100% working interest position in approximately 7,500 acres. The well permitting process is ongoing. In 2006 we drilled 14 Fruitland Coal CBM wells and 1 saltwater disposal well. We have identified 40 drillable locations on our San Juan Basin leases with 18 wells planned for 2007.

**Mid-Continent**

*Texas Panhandle —Price Ranch Project.* On February 10, 2006, we acquired a farmout from BP on approximately 12,800 acres in Sherman County, Texas, to explore for oil and gas reserves in the Marmaton Limestone and Morrow Sandstone. The acreage is held by production by shallower Chase Formation Hugoton gas production. The farmout includes access to a proprietary BP 22 square miles of 3-D seismic survey, which was reprocessed for prospect development. We have acquired a 3.5-mile 2-D seismic line to evaluate several well locations offsetting existing Marmaton production. Three drillable prospects resulted from the seismic and geologic evaluations. Subsequent to December 31, 2006, one of these prospects has been drilled, and another is expected to commence drilling by the end of the first quarter of 2007.

**Crude Oil and Natural Gas Operations**

***Production by Operating Area***

The following table presents certain information with respect to our production data for the period presented:

| | For the Year Ended December 31, 2006 (1) | | |
|---|---|---|---|
| | Natural Gas (Bcf) | Oil (MMBbls) | Equivalents (Bcfe) |
| California | 11.4 | - | 11.5 |
| Lobo | 9.3 | - | 9.7 |
| Perdido | 4.0 | - | 4.2 |
| State Waters | 1.1 | - | 1.1 |
| Gulf of Mexico | 1.5 | 0.3 | 3.0 |
| Other Onshore | 2.4 | 0.2 | 3.3 |
| Rocky Mountains | 0.4 | - | 0.4 |
| Mid-Continent | 0.2 | - | 0.2 |
| | 30.3 | 0.5 | 33.4 |

(1) Excludes properties not conveyed as part of the Acquisition of the domestic oil and natural gas properties of Calpine, as described in the footnotes for proved reserves below.

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***Proved Reserves***

There are a number of uncertainties inherent in estimating quantities of proved reserves, including many factors beyond our control, such as commodity pricing. Therefore, the reserve information in this report represents only estimates. Reserve engineering is a subjective process of estimating underground accumulations of oil and natural gas that cannot be measured in an exact manner. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. As a result, estimates of different engineers may vary. In addition, results of drilling, testing and production subsequent to the date of an estimate may justify revising the original estimate. Accordingly, initial reserve estimates are often different from the quantities of oil and natural gas that are ultimately recovered. The meaningfulness of such estimates depends primarily on the accuracy of the assumptions upon which they were based. Except to the extent that we acquire additional properties containing proved reserves or conduct successful exploration and development activities, or both, our proved reserves will decline as reserves are produced.

As of December 31, 2006, we had 407.8 Bcfe of proved oil and natural gas reserves, including 390.2 Bcf of natural gas and 2,930 MBbls of oil and condensate. Using prices as of December 31, 2006, (adjusted for basis and quality differentials) the estimated standardized measure of discounted future net cash flows was $721.7 million. The following table sets forth by operating area a summary of our estimated net proved reserve information as of December 31, 2006:

| | **Estimated Proved Reserves at December 31, 2006 (1)(2)(3)** | | | |
|---|---|---|---|---|
| | **Developed (Bcfe)** | **Undeveloped (Bcfe)** | **Total (Bcfe)** | **Percent of Total Reserves** |
| California | 115.4 | 37.2 | 152.6 | 37% |
| Lobo | 87.7 | 83.7 | 171.4 | 42% |
| Perdido | 8.3 | 11.6 | 19.9 | 5% |
| State Waters | 2.2 | - | 2.2 | 1% |
| Gulf of Mexico | 13.8 | 1.8 | 15.6 | 4% |
| Other Onshore | 18.4 | 6.6 | 25.0 | 6% |
| Rockies | 15.0 | 3.5 | 18.5 | 4% |
| Mid-Continent | 2.1 | 0.5 | 2.6 | 1% |
| Total | 262.9 | 144.9 | 407.8 | 100% |

(1) These estimates are based upon a reserve report prepared by Netherland Sewell & Associates, Inc. (hereafter “Netherland Sewell”) using criteria in compliance with the Securities and Exchange Commission (“SEC”) guidelines and excludes 23.4 Bcfe of proved oil and gas reserves with an SEC PV-10 value of $53.0 million pretax representing the total allocated value of wells and the associated leases described in footnote 2 below.

(2) At the July 2005 closing of the Acquisition, we withheld $68 million for properties (excluding that portion of the properties subject to the preferential right) which Calpine agreed to transfer legal title to us but for which Calpine had not then secured consents to assign, which the parties believed at that time were required (“Non-Consent Properties”). Subsequent analysis determined that a portion of these properties, having an allocated value withheld under the Purchase Agreement at closing of $29 million, did not require such consent. Consents now have been received for the remaining properties as to which the allocated value under the Purchase Agreement withheld at closing, was $39 million (“Cured Non-Consent Properties”). We are prepared to pay Calpine the retained portion of the original purchase price, upon our receipt from Calpine of record legal title on these properties, free of any encumbrance, subject to appropriate adjustment for the net revenues through the relevant pre-petition period

related to the Cured Non-Consent Properties, and Calpine's performance of its obligations under the "further assurances" provisions of the Purchase Agreement.

(3) Includes properties subject to additional documentation or completion of ministerial actions by federal or state agencies necessary to perfect legal title issues discovered during routine post-closing analysis after the Acquisition of the domestic oil and natural gas business from Calpine, for which Calpine is contractually obligated to assist in resolving.

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**2006 Capital Expenditures**

The following table summarizes information regarding development and exploration capital expenditures for the year ended December 31, 2006 (Successor), six months ended December 31, 2005 (Successor), the six months ended June 30, 2005 (Predecessor) and the capital expenditures for the year ended December 31, 2004 (Predecessor).

| | Successor | | Predecessor | |
|---|---|---|---|---|
| | Year Ended December 31, 2006 | Six Months Ended December 31, 2005 | Six Months Ended June 30, 2005 | Year Ended December 31, 2004 |
| | (In thousands) | | | |
| Capital Expenditures by Operating Area: | | | | |
| California | $ 39,691 | $ 3,933 | $ 4,572 | $ 8,239 |
| Lobo | 51,911 | 6,775 | 2,020 | 8,670 |
| Perdido | 25,971 | 9,268 | 12,441 | 18,683 |
| Texas State Waters | 13,028 | 3,023 | 3,417 | - |
| Other Onshore | 10,207 | 10,831 | 2,300 | 8,207 |
| Gulf of Mexico | 17,958 | 9,369 | 4,556 | 4,174 |
| Rocky Mountains | 15,299 | 3,035 | 1,102 | - |
| Mid-Continent | 3,371 | 317 | 220 | 300 |
| Leasehold | 16,383 | 9,224 | 2,617 | 3,559 |
| New acquisitions | 35,105 | 5,524 | - | - |
| Delay rentals | 728 | 143 | 443 | 507 |
| Geological and geophysical/seismic | 3,748 | 5,659 | 513 | 199 |
| Total capital expenditures (1) | $ 233,400 | $ 67,101 | $ 34,201 | $ 52,538 |

(1) Capital expenditures for the year ended December 31, 2006 (Successor) excludes capitalized overhead costs of \$3.4 million, capitalized interest of \$2.1 million and corporate other capitalized costs of \$1.7 million. The six months ended December 31, 2005 (Successor) excludes capitalized interest of \$0.6 million, corporate other capitalized costs of \$1.6 million and capitalized overhead costs of \$1.7 million. Corporate other capitalized costs consist of costs related to IT software/hardware, office furniture and fixtures and license transfer fees. The six-month period ended June 30, 2005 (Predecessor) excludes \$(0.7) million of capitalized interest and \$1.7 million of overhead. The amount for 2004 (Predecessor) excludes \$1.3 million of capitalized interest, \$3.1 million of overhead, \$10.0 million of compressor station and gathering system expense and \$1.4 million for acquisition properties. Our total capital expenditures in 2004 of \$52.5 million, including these exclusions, corresponds to 2004 total capital costs of \$69 million as defined under Statement of Financial Accounting Standards (“SFAS”) No. 19, “Financial Accounting and Reporting by Oil and Gas Producing Companies” in the Supplemental Oil and Gas Disclosure under Item 8 of this report.

**Productive Wells and Acreage**

The following table sets forth our interest in undeveloped acreage, developed acreage and productive wells in which we own a working interest as of December 31, 2006. Gross represents the total number of acres or wells in which we own a working interest. Net represents our proportionate working interest resulting from our ownership in the gross acres or wells. Productive wells are wells in which we have a working interest and that are capable of producing oil or natural gas.

| | **Undeveloped Acres (1)** | | **Developed Acres (1)** | | **Productive Wells** | |
|---|---|---|---|---|---|---|
| | **Gross** | **Net** | **Gross** | **Net** | **Gross** | **Net** |
| California | 45,364 | 35,247 | 47,184 | 41,695 | 142 | 118 |
| Lobo | 24,716 | 21,105 | 53,519 | 45,699 | 359 | 188 |
| Perdido | 4,128 | 2,073 | 13,898 | 6,940 | 28 | 14 |
| Texas State Waters | 8,860 | 4,536 | 2,408 | 715 | 2 | 1 |
| Other Onshore | 11,647 | 7,651 | 29,797 | 21,608 | 161 | 45 |
| Gulf of Mexico (2) | 15,805 | 9,375 | 38,695 | 22,514 | 4 | 3 |
| Rocky Mountains | 189,511 | 149,983 | 8,859 | 6,160 | 25 | 22 |
| Mid-Continent | 280 | 52 | 2,675 | 2,561 | 30 | 8 |
| | 300,311 | 230,022 | 197,035 | 147,892 | 751 | 399 |

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Capital

(1) Includes acreage relating to properties for which legal title was not transferred to us on the original date of the Acquisition because consents to transfer which were believed at that time to be required and had not yet been obtained is included in this table.

(2) Offshore productive wells are based on intervals rather than well bores.

The following table shows our interest in undeveloped acreage as of December 31, 2006, which is subject to expiration in 2007, 2008, 2009, and thereafter.

| 2007 | | 2008 | | 2009 | | Thereafter | |
|---|---|---|---|---|---|---|---|
| **Gross** | **Net** | **Gross** | **Net** | **Gross** | **Net** | **Gross** | **Net** |
| 15,379 | 10,374 | 25,830 | 22,929 | 32,648 | 25,366 | 226,454 | 171,353 |

**Drilling Activity**

The following table sets forth the number of gross exploratory and gross development wells drilled in which we participated during the last three fiscal years. The number of wells drilled refers to the number of wells commenced at any time during the respective fiscal year. Productive wells are either producing wells or wells capable of commercial production. At December 31, 2006, we were in the process of drilling six gross wells.

| | Gross Wells | | | | | |
|---|---|---|---|---|---|---|
| | Exploratory | | | Development | | |
| | **Productive** | **Dry** | **Total** | **Productive** | **Dry** | **Total** |
| 2006 | 68.0 | 15.0 | 83.0 | 51.0 | 8.0 | 59.0 |
| 2005 | 7.0 | 5.0 | 12.0 | 41.0 | 3.0 | 44.0 |
| 2004 | 8.0 | 2.0 | 10.0 | 40.0 | 2.0 | 42.0 |

The following table sets forth, for each of the last three fiscal years, the number of net exploratory and net development wells drilled by us based on our proportionate working interest in such wells.

| | Net Wells | | | | | |
|---|---|---|---|---|---|---|
| | Exploratory | | | Development | | |
| | **Productive** | **Dry** | **Total** | **Productive** | **Dry** | **Total** |
| 2006 | 58.5 | 10.0 | 68.5 | 45.0 | 6.2 | 51.2 |
| 2005 | 3.4 | 3.4 | 6.8 | 23.5 | 3.0 | 26.5 |
| 2004 | 4.3 | 1.0 | 5.3 | 21.1 | 2.0 | 23.1 |

**Marketing and Customers**

Pursuant to our natural gas purchase and sales contract with Calpine and its subsidiaries, we are obligated to sell all of the then-existing and future production from our California leases in production as of May 1, 2005, through December 2009, based on market prices. Calpine maintains a right of first refusal for a term of 10 years after the primary term. As of December 31, 2006, this production comprised approximately 40% of our current overall daily equivalent production. Under the terms of our gas purchase and sale contract and spot agreements with Calpine, cash payment for all natural gas volumes that are contractually sold to Calpine on the previous day are deposited into our collateral bank account. If the funds are not deposited one business day in arrears in accordance with our contract, we are not obligated to continue to sell our production to Calpine and these sales can then cease immediately. We would then be in a position to market this natural gas production to other parties. Calpine has 60 days to pay amounts owed to us, at which time we are obligated under the contract to resume natural gas sales to Calpine. We believe that Calpine's bankruptcy will have no significant effect on our ability to sell our natural gas at market prices. Additionally, while we may market our natural gas production, which is not subject to the above mentioned natural gas contract, to parties other than Calpine, an affiliate of Calpine is under contract through June 30, 2007, to provide us administrative services in connection with such marketing efforts.

All of our other production is sold to various purchasers, including Calpine, on a competitive basis.

**Major Customers**

For the year ended December 31, 2006, the Company had two major customers, which accounted for approximately 60% of the Company's consolidated annual revenue. Calpine Energy Services ("CES") was one of the major customers and accounted for approximately 45% of the Company's consolidated annual revenue. Total Gas and Power was the other major customer.

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**Competition**

The oil and natural gas industry is highly competitive, and we compete with a substantial number of other companies that have greater resources. Many of these companies explore for, produce and market oil and natural gas, carry on refining operations and market the resultant products on a worldwide basis. The primary areas in which we encounter substantial competition are in locating and acquiring desirable leasehold acreage for our drilling and development operations, locating and acquiring attractive producing oil and natural gas properties, and obtaining purchasers and transporters of the oil and natural gas we produce. There is also competition between producers of oil and natural gas and other industries producing alternative energy and fuel. Furthermore, competitive conditions may be substantially affected by various forms of energy legislation and/or regulation considered from time to time by the federal, state and local government; however, it is not possible to predict the nature of any such legislation or regulation that may ultimately be adopted or its effects upon our future operations. Such laws and regulations may, however, substantially increase the costs of exploring for, developing or producing natural gas and oil and may prevent or delay the commencement or continuation of a given operation. The effect of these risks cannot be accurately predicted.

**Seasonal Nature of Business**

Generally, but not always, the demand for natural gas decreases during the summer months and increases during the winter months. Seasonal anomalies such as mild winters or abnormally hot summers sometimes lessen this fluctuation. In addition, certain natural gas users utilize natural gas storage facilities and purchase some of their anticipated winter requirements during the summer. This can also lessen seasonal demand fluctuations. Seasonal weather conditions and lease stipulations can limit our drilling and producing activities and other oil and natural gas operations in certain areas of the Rocky Mountain region. These seasonal anomalies can increase competition for equipment, supplies and personnel during the spring and summer months, which could lead to shortages and increase costs or delay our operations.

**Regulation**

The oil and natural gas industry in the United States is subject to extensive regulation by federal, state and local authorities. We hold onshore and offshore federal leases involving the United States Department of Interior (the Bureau of Land Management, the Bureau of Indian Affairs and the Minerals Management Service). At the federal level, various federal rules, regulations and procedures apply, including those issued by the United States Department of Interior as noted above, and the United States Department of Transportation (U.S. Coast Guard and Office of Pipeline Safety). At the state and local level, various agencies and commissions regulate drilling, production and midstream activities. These federal, state and local authorities have various permitting, licensing and bonding requirements. Varied remedies are available for enforcement of these federal, state and local rules, regulations and procedures, including fines, penalties, revocation of permits and licenses, actions affecting the value of leases, wells or other assets, and suspension of production. As a result, there can be no assurance that we will not incur liability for fines and penalties or otherwise subject us to the various remedies as are available to these federal, state and local authorities. However, we believe that we are currently in material compliance with these federal, state and local rules, regulations and procedures.

*Transportation and Sale of Natural Gas.* The Federal Energy Regulatory Commission ("FERC") regulates interstate natural gas pipeline transportation rates and service conditions. Although the FERC does not regulate natural gas producers such as us, the agency's actions are intended to foster increased competition within all phases of the natural gas industry. To date, the FERC's pro-competition policies have not materially affected our business or operations. It is unclear what impact, if any, future rules or increased competition within the natural gas industry will have on our natural gas sales efforts.

The FERC, the United States Congress or state regulatory agencies may consider additional proposals or proceedings that might affect the natural gas industry. We cannot predict when or if these proposals will become effective or any effect they may have on our operations. We do not believe, however, that any of these proposals will affect us any differently than other natural gas producers with which we compete.

*Regulation of Production.* Oil and natural gas production is regulated under a wide range of federal, state and municipal (or other local) statutes, rules, orders and regulations. Federal, state and municipal statutes and regulations require permits for drilling operations, drilling bonds and reports concerning operations. The states in which we own and operate properties have regulations governing conservation matters, including provisions for the unitization or pooling of oil and natural gas properties, the establishment of maximum rates of production from oil and natural gas wells and the regulation of the spacing and plugging and abandonment of wells. Many states also restrict production to the market demand for oil and gas, and several states have indicated interest in revising applicable regulations. These regulations limit the amount of oil and gas we can produce from our wells and limit the number of wells or the locations at which we can drill. Also, each state generally imposes an ad valorem, production or severance tax with respect to production and sale of oil, natural gas and natural gas liquids within its jurisdiction.

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*U.S. Minerals Management Services of the Department of the Interior.* The MMS has broad authority to regulate our oil and natural gas operations on offshore leases in federal waters. It must approve and grant permits in connection with our drilling and development plans. Additionally, the MMS has promulgated regulations requiring offshore production facilities to meet stringent engineering and construction specifications restricting the flaring or venting of natural gas, governing the plugging and abandonment of wells and controlling the removal of production facilities. Under certain circumstances, the MMS may suspend or terminate any of our operations on federal leases, and has proposed regulations that would permit it to expel unsafe operators from offshore operations. Delays in the approval of plans and issuance of permits by the MMS because of staffing, economic, environmental or other reasons could adversely affect our operations. The MMS has also established rules governing the calculation of royalties and the valuation of oil and natural gas produced from federal onshore and offshore leases and regulations regarding deductible costs.

*Environmental Regulations.* Processes involved in the drilling, construction, extraction and transportation of oil and natural gas in the exploration and production industry are subject to extensive operating rules and regulations that have been promulgated by federal, state and local authorities with the intent of conserving natural resources, preservation of the environment and protection of human health. Environmental regulations affecting us prohibit or control the emitting or discharge of regulated pollutants into the atmosphere, underground sources of drinking water, ground water supplies, surface waters of the United States, or to unprotected surface soils on or in the vicinity of our operations. The environmental statutes provide for sensitive habitat, endangered species, wetlands loss and waste management practices. The standards in many cases require a lengthy and complex process of obtaining licenses, permits and approvals from federal, state and local agencies. Inherent in the environmental legal system affecting our business are the following primary compliance obligations which often require costly precautionary measures or lend us to serious enforcement consequences:

- Notification requirements
- Point of discharge or “Waste End” controls
- Process oriented controls and pollution prevention
- Regulation of activities to protect resources, species or ecological amenities
- Safe transportation requirements
- Response and remediation requirements
- Compensation requirements.

The environmental regulations provide for criminal prosecution of responsible corporate officials under certain circumstances. In addition, the environmental regulations also provide for civil enforcement actions in certain circumstances.

The environmental laws with their implementing regulations with the most significant impact on the oil and natural gas exploration and production industry include the following:

- Clean Air Act (“CAA”)
- Clean Water Act (“CWA”)

- Comprehensive Environmental Response, Compensation & Liability Act (“CERCLA”)
- National Environmental Policy Act (“NEPA”)
- Oil Pollution Act of 1990 (“OPA’90”)
- Resource Conservation & Recovery Act (“RCRA”)
- Safe Drinking Water Act
- Superfund Amendments & Reauthorization Act (“SARA”)

Environmental laws and regulations are subject to change, and we are unable to predict the ongoing cost of complying with them or their future impact on our operations. A violation of environmental laws and regulations and any related permits may result in administrative, civil or criminal penalties, injunctions and delays. Discharge of hydrocarbons or hazardous substances into the environment to the extent the event is not insured, may result in substantial expense, including both the cost to comply with the applicable laws and regulations and claims made by neighboring landowners and other third parties for personal injury and property damage.

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We believe that we are currently in substantial compliance with the requirements of these statutes and related state and local laws and regulations, and that we hold all necessary and up-to-date permits, registrations and other authorizations to the extent they are required by our operations under such laws.

*Occupational Safety & Health Act* ("OSHA"). The Williams-Steiger Occupational Safety and Health Act of 1970 requires, in part, that every employer covered under OSHA furnish its employees a place of employment which is free from recognized hazards that are causing or are likely to cause death or serious physical harm to its employees. OSHA also requires that employers comply with occupational safety and health standards promulgated under OSHA, and that employees comply with standards, rules, regulations and orders issued under the Act which are applicable to their own actions and conduct. OSHA authorizes the Department of Labor to conduct inspections, and to issue citations and proposed penalties for alleged violations. OSHA, under section 20(b), also authorizes the Secretary of Health, Education, and Welfare to conduct inspections and to question employers and employees in connection with research and other related activities. OSHA contains provisions for adjudication of violations, periods prescribed for the abatement of violations, and proposed penalties by the Occupational Safety and Health Review Commission, if contested by an employer or by an employee or authorized representative of employees, and for judicial review.

**Insurance Matters**

As is common in the oil and natural gas industry, we do not insure fully against all risks associated with our business either because such insurance is not available or because premium costs are considered prohibitive. A loss not fully covered by insurance could have a materially adverse effect on our financial position, results of operations or cash flows. In analyzing our operations and insurance needs, and in recognition that we have a large number of individual well locations with varied geographical distribution, we compared premium costs to the likelihood of material loss of production. Based on this analysis, we have elected, at this time, not to carry loss of production or business interruption insurance for our operations.

**Employees**

As of March 5, 2007, we have 135 full time employees. We also contract for the services of independent consultants involved in land, regulatory accounting, financial and other disciplines as needed. None of our employees are represented by labor unions or covered by any collective bargaining agreement. We believe that our relations with our employees are satisfactory.

**Access to Company Reports**

For further information pertaining to us, you may inspect without charge at the public reference facilities of the SEC at 100 F Street, NE, Room 1580, Washington, D.C. 20549 any of our filings with the SEC. Copies of all or any portion of the documents may be obtained by calling the SEC at 1-800-SEC-0330. In addition, the SEC maintains a web site that contains reports, proxy and information statements and other information that is filed electronically with the SEC. The web site can be accessed at *www.sec.gov*.

**Corporate Governance Matters**

Our website is *http://www.rosettaresources.com.* All corporate filings with the SEC can be found on our website, as well as other information related to our business. Under the Corporate Governance tab you can find copies of our Code of Business Conduct and Ethics, our Nominating and Corporate Governance Committee Charter, our Audit Committee Charter, and our Compensation Committee Charter.

**Item 1A. Risk Factors**

***Calpine's bankruptcy filing may adversely affect us in several respects.***

*Calpine, its creditors or interest holders may challenge the fairness of some or all of the Acquisition.*

Five and one-half months after the Acquisition, Calpine and certain of its subsidiaries (the "Debtors") filed for protection under the federal bankruptcy laws in the Bankruptcy Court on December 20, 2005 (the "Petition Date"). Calpine or its Bankruptcy estate may bring an action under the Bankruptcy Code or relevant state fraudulent conveyance laws asserting that Calpine's transfer of its domestic oil and natural gas business to us (as either the alleged initial transferee or the immediate or mediate transferee from the initial transferee) should be voided or set aside as a fraudulent transfer or, alternatively, entitles Calpine's estate monetary relief to the extent Rosetta is found not to have paid reasonably equivalent value. To prevail in such a legal action, Calpine, its creditors or interest holders would be required to prove that Calpine either:

- Transferred its domestic oil and natural gas business to us with the intent of hindering, delaying or defrauding its current or future creditors; or

- As of July 7, 2005 (the date of the closing of the Acquisition), (a) received less than reasonably equivalent value for the business, and (b) was insolvent, became insolvent as a result of such transfer, was engaged in a business or transaction or was about to engage in a business or transaction for which any property remaining was unreasonably small, or intended to incur or believed it would incur debts that would be beyond its ability to pay as such debts matured.

Our primary defense against such a legal challenge rests on the extensive negotiations leading up to, and the market pricing mechanisms incorporated within the terms and procedure of the Acquisition. Nonetheless, if after a trial on the merits, the Bankruptcy Court was to determine that the Debtors have met their burden of proof, it could void the transfer or take other actions against us, including (i) setting aside the Acquisition and returning our purchase price and give us a first lien on all the properties and assets we purchased in the Acquisition or (ii) sustaining the Acquisition subject to our being required to pay the Debtors the amount, if any, by which the fair value of the business transferred, as determined by the Bankruptcy Court as of July 7, 2005, exceeded the purchase price determined and paid in July 2005. If the Bankruptcy Court should so rule, a setting aside of the Acquisition would be materially detrimental to us in that substantially all our properties conveyed at the time of the Acquisition would be returned to Calpine, subject to our right (as a good faith transferee) to retain a lien in our favor to secure the return of the purchase price we paid for the properties. Additionally, if the Bankruptcy Court should so rule, any requirement to pay an increased purchase price could adversely affect us depending on the amount we might be required to pay. See Item 3. Legal Proceedings for further information regarding the Calpine bankruptcy.

*The bankruptcy proceeding may prevent, frustrate or delay our ability to receive record legal title to certain properties originally determined to be Non-Consent Properties which we are entitled to receive under the Purchase Agreement.*

At the closing of the Acquisition, Calpine agreed to sell but retained legal title to certain domestic oil and natural gas properties, subject to obtaining various third party consents or waivers of preferential purchase rights, which the parties believe at the time were required, in order to effect transfer of legal title. In July 2005, as part of the transactions undertaken in connection with closing the Acquisition, we accepted possession of and have since been operating all of the properties for which Calpine retained record legal title. We withheld approximately $75 million from the aggregate purchase price, which was the allocated dollar amount under the Purchase Agreement for the remaining properties. Subsequent to the closing of the Acquisition, with the exception of the properties subject to the preferential right to purchase, we obtained substantially all of the consents to assign for all of these remaining properties for which consents were actually required. Prior to the Calpine bankruptcy, we were prepared to consummate the assignments of legal title for these remaining properties, except those subject to properly executed preferential rights to purchase. The SEC PV-10 value of these properties at December 31, 2005 was approximately $72.4 million pretax. Based on our internal calculations, we estimate the SEC PV-10 value of these properties at current market prices at December 31, 2006 to be approximately $53.0 million pretax. We are prepared to pay Calpine the retained portion of the original purchase price, approximately $68 million, and approximately $11 million in other true-up payment obligations, all upon our receipt from Calpine of record legal title, free of any encumbrances, for that portion of these properties which are the Non-Consent Properties, subject to appropriate adjustment for the net revenues and expenses through December 15, 2005 and Calpine's performance of its obligations under the "further assurances" provisions of the Purchase Agreement. If the assignment of any remaining properties (including any leases) does not occur, the portion of the purchase price we held back pending consent or waiver will be retained by us and will be available to us for general corporate purposes.

*The bankruptcy proceeding may prevent, frustrate or delay our ability to receive corrective documentation from Calpine for certain properties that we bought from Calpine and paid for, in cases where Calpine delivered incomplete documentation, including documentation related to certain ministerial governmental approvals.*

Certain of the properties we purchased from Calpine and paid Calpine for on July 7, 2005, require certain additional documentation, depending on the particular facts and circumstances surrounding the particular properties involved, such documentation to be delivered by Calpine to quiet title related to our ownership of these properties. Certain of these properties are subject to ministerial governmental action approving us as qualified assignee and operator, even though in most cases there had been a conveyance by Calpine and release of mortgages and liens by Calpine's creditors. For certain other properties, the documentation delivered by Calpine at closing was incomplete. While we remain hopeful that Calpine will continue to work cooperatively with us to secure these ministerial governmental approvals and accomplish the curative corrections for all of these properties for which we paid Calpine for, all of the same being covered, we believe, by the further assurances provision of the Purchase Agreement, the exact details for each property involved and how, when and if this will be able to be secured or accomplished continue to remain uncertain at this stage of Calpine's bankruptcy.

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Additionally, on June 29, 2006, Calpine filed a Section 365 motion in connection with its pending bankruptcy proceeding seeking entry of an order authorizing Calpine to assume certain oil and natural gas leases which Calpine previously sold or agreed to sell to us in the Acquisition, to the extent those leases constitute “unexpired leases of non-residential real property” and were not fully transferred to us at the time of Calpine’s filing for bankruptcy. According to this motion, Calpine filed it to avoid the automatic forfeiture of any interest it might have in these leases by operation of a statutory deadline. Calpine’s motion did not request that the Bankruptcy Court determine whether these properties belong to us or to Calpine. Generally, oil and gas leases are regarded as real property and not leases of real property despite their being called leases. If the Bankruptcy Court were to later conclude that the oil and natural gas leases are “unexpired leases of non-residential real property,” and that we had no interest in them, we may be required to take further action or pay further consideration to complete the assignments of these interests or Calpine could retain the leases. In light of Calpine’s obligations under the Purchase Agreement and rights afforded purchasers of real property, we would oppose any such request or effort. Any failure by Calpine to complete the corrective action necessary to remove title deficiencies with respect to certain of these properties, including decision of the Bankruptcy Court not to require Calpine to deliver corrective documentation or to require us to pay additional consideration, could result in a material adverse effect on our results of operations or financial condition if we are not able to receive any offsetting refund of the portion of the purchase price attributable to those properties or if the amount of additional consideration we are required to pay is material.

*We have expended and may continue to expend significant resources in connection with Calpine’s bankruptcy.*

We have expended and may continue to expend significant resources in connection with Calpine’s bankruptcy. These resources include our increased costs for lawyers, consultant experts and related expenses, as well as lost opportunity costs associated with our dedicating internal resources to these matters. If we continue to expend significant resources and our management is distracted from the operational matters by the Calpine bankruptcy, our business, results of operations, financial position or cash flows could be adversely affected.

***Oil and natural gas prices are volatile, and a decline in oil and natural gas prices would significantly affect our financial results and impede our growth.***

Our revenue, profitability and cash flow depend substantially upon the prices and demand for oil and natural gas. The markets for these commodities are volatile and even relatively modest drops in prices can significantly affect our financial results and impede our growth. Prices for oil and natural gas fluctuate widely in response to relatively minor changes in the supply and demand for oil and natural gas, market uncertainty and a variety of additional factors beyond our control, such as:

- Domestic and foreign supply of oil and gas;
- Price and quantity of foreign imports;
- Actions of the Organization of Petroleum Exporting Countries and state-controlled oil companies relating to oil price and production controls;
- Domestic and foreign governmental regulations;
- Political conditions in or affecting other oil producing and natural gas producing countries, including the current conflicts in the Middle East and conditions in South America and Russia;
- Weather conditions and natural disasters;

- Technological advances affecting oil and natural gas consumption;
- Overall U.S. and global economic conditions; and
- Price and availability of alternative fuels.

Further, oil and natural gas prices do not necessarily fluctuate in direct relationship to each other. Because the majority of our estimated proved reserves are natural gas reserves, our financial results are more sensitive to movements in natural gas prices. Lower oil and natural gas prices may not only decrease our revenues on a per unit basis but also may reduce the amount of oil and natural gas that we can produce economically. Thus a significant reduction in commodity prices may result in our having to make substantial downward adjustments to our estimated proved reserves and could have a material adverse effect on our financial condition, results of operations and cash flows.

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***Development and exploration drilling activities do not ensure reserve replacement and thus our ability to produce revenue.***

Development and exploration drilling and strategic acquisitions are the main methods of replacing reserves. However, development and exploration drilling operations may not result in any increases in reserves for various reasons. Development and exploration drilling operations may be curtailed, delayed or cancelled as a result of:

- Lack of acceptable prospective acreage;
- Inadequate capital resources;
- Weather conditions and natural disasters;
- Title problems;
- Compliance with governmental regulations;
- Mechanical difficulties; and
- Availability of equipment.

***Counterparty credit default could have an adverse effect on us.***

Our revenues are generated under contracts with various counterparties. Results of operations would be adversely affected as a result of non-performance by any of these counterparties of their contractual obligations under the various contracts. A counterparty's default or non-performance could be caused by factors beyond our control such as a counterparty experiencing credit default. A default could occur as a result of circumstances relating directly to the counterparty, or due to circumstances caused by other market participants having a direct or indirect relationship with the counterparty. Defaults by counterparties may occur from time to time, and this could negatively impact our results of operations, financial position and cash flows. Calpine's recent bankruptcy could result in the failure of Calpine to continue purchasing natural gas from us under our natural gas purchase and sale agreements with Calpine discussed below.

***We sell a significant amount of our production to one customer.***

In connection with the Acquisition, we entered into a natural gas purchase and sale contract with Calpine that obligates us to sell all of the then-existing and future production from our California leases in production as of May 1, 2005 through December 31, 2009 based on market prices. Calpine maintains a right of first refusal for a term of 10 years after the primary term. As of December 31, 2006, this production comprised approximately 40% of our current overall production based on an equivalent basis. Calpine's recent bankruptcy could result in failure of Calpine to continue purchasing natural gas from us. Additionally, under separate monthly spot agreements, we may sell our natural gas production, not subject to the term contract to Calpine, which could increase our credit exposure to Calpine. Under the terms of our natural gas purchase and sale contract and spot agreements with Calpine, all natural gas volumes that are contractually sold to Calpine are collateralized by Calpine making margin payments one business day in arrears to our collateral account equal to the previous day's natural gas sales. In the event of a default by Calpine, we could be exposed to the loss of up to four days of natural gas sales revenue under the contract, which at prices and volumes in effect as of December 31, 2006 would be approximately $2.5 million.

***Unless we replace our oil and natural gas reserves, our reserves and production will decline.***

Our future oil and natural gas production depends on our success in finding or acquiring additional reserves. If we fail to replace reserves through drilling or acquisitions, our level of production and cash flows will be affected adversely. In general, production from oil and natural gas properties declines as reserves are depleted, with the rate of decline depending on reservoir characteristics. Our total proved reserves decline as reserves are produced. Our ability to make the necessary capital investment to maintain or expand our asset base of oil and natural gas reserves would be impaired to the extent cash flow from operations is reduced and external sources of capital become limited or unavailable. We may not be successful in exploring for, developing or acquiring additional reserves.

***We will require additional capital to fund our future activities. If we fail to obtain additional capital, we may not be able to implement fully our business plan, which could lead to a decline in reserves.***

Future projects and acquisitions may depend on our ability to obtain financing beyond our cash flow from operations. We will finance our business plan and operations primarily with internally generated cash flow, bank borrowings, entering into exploratory arrangements with other parties and publicly or privately raised equity. In the future, we will require substantial capital to fund our business plan and operations. Sufficient capital may not be available on acceptable terms or at all. If we cannot obtain additional capital resources, we may curtail our drilling, development and other activities or be forced to sell some of our assets on unfavorable terms.

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***The terms of our credit facilities contain a number of restrictive and financial covenants that limit our ability to pay dividends. If we are unable to comply with these covenants, our lenders could accelerate the repayment of our indebtedness.***

The terms of our credit facilities subject us to a number of covenants that impose restrictions on us, including our ability to incur indebtedness and liens, make loans and investments, make capital expenditures, sell assets, engage in mergers, consolidations and acquisitions, enter into transactions with affiliates, enter into sale and leaseback transactions, change our lines of business and pay dividends on our common stock. We will also be required by the terms of our credit facilities to comply with financial covenant ratios. A more detailed description of our credit facilities is included in "Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources" and the footnotes to the Consolidated/Combined Financial Statements.

A breach of any of the covenants imposed on us by the terms of our indebtedness, including the financial covenants under our credit facilities, could result in a default under such indebtedness. In the event of a default, the lenders for our revolving credit facility could terminate their commitments to us, and they and the lenders of our second lien term loan could accelerate the repayment of all of our indebtedness. In such case, we may not have sufficient funds to pay the total amount of accelerated obligations, and our lenders under the credit facilities could proceed against the collateral securing the facilities. Any acceleration in the repayment of our indebtedness or related foreclosure could adversely affect our business.

***Properties we acquire may not produce as expected, and we may be unable to determine reserve potential, identify liabilities associated with the properties or obtain protection from sellers against such liabilities.***

We continually review opportunities to acquire producing properties, undeveloped acreage and drilling prospects; however, such reviews are not capable of identifying all potential conditions. Generally, it is not feasible to review in depth every individual property involved in each acquisition. Ordinarily, we will focus our review efforts on higher value properties or properties with known adverse conditions and will sample the remainder.

However, even a detailed review of records and properties may not necessarily reveal existing or potential problems or permit a buyer to become sufficiently familiar with the properties to assess fully their condition, any deficiencies, and development potential. Inspections may not always be performed on every well, and environmental problems, such as ground water contamination are not necessarily observable even when an inspection is undertaken.

***Our exploration and development activities may not be commercially successful.***

Exploration activities involve numerous risks, including the risk that no commercially productive oil or natural gas reservoirs will be discovered. In addition, the future cost and timing of drilling, completing and producing wells is often uncertain. Furthermore, drilling operations may be curtailed, delayed or canceled as a result of a variety of factors, including:

- Unexpected drilling conditions; pressure or irregularities in formations; equipment failures or accidents;
- Adverse weather conditions, including hurricanes, which are common in the Gulf of Mexico during certain times of the year; compliance with governmental regulations; unavailability or high cost of drilling rigs, equipment or labor;
- Reductions in oil and natural gas prices; and
- Limitations in the market for oil and natural gas.

Our decisions to purchase, explore, develop and exploit prospects or properties depend in part on data obtained through geophysical and geological analyses, production data and engineering studies, the results of which are often uncertain. Even when used and properly interpreted, 3-D seismic data and visualization techniques only assist geoscientists in identifying subsurface structures and hydrocarbon indicators. They do not allow the interpreter to know conclusively if hydrocarbons are present or producible economically. In addition, the use of 3-D seismic and other advanced technologies requires greater pre-drilling expenditures than traditional drilling strategies. Because of these factors, we could incur losses as a result of exploratory drilling expenditures. Poor results from exploration activities could have a material adverse effect on our future cash flows, results of operations and financial position.

***Numerous uncertainties are inherent in our estimates of oil and natural gas reserves and our estimated reserve quantities and present value calculations may not be accurate. Any material inaccuracies in these reserve estimates or underlying assumptions will affect materially the estimated quantities and present value of our reserves.***

Estimates of proved oil and natural gas reserves and the future net cash flows attributable to those reserves are prepared by independent petroleum engineers and geologists. There are numerous uncertainties inherent in estimating quantities of proved oil and natural gas reserves and cash flows attributable to such reserves, including factors beyond our control and that of our engineers. Reserve engineering is a subjective process of estimating underground accumulations of oil and natural gas that cannot be measured in an exact manner. The accuracy of an estimate of quantities of reserves, or of cash flows attributable to such reserves, is a function of the available data, assumptions regarding future oil and natural gas prices, expenditures for future development and exploration activities, engineering and geological interpretation and judgment. Additionally, reserves and future cash flows may be subject to material downward or upward revisions, based upon production history, development and exploration activities and prices of oil and natural gas. Actual future production, revenue, taxes, development expenditures, operating expenses, underlying information, quantities of recoverable reserves and the value of cash flows from such reserves may vary significantly from the assumptions and underlying information set forth herein. In addition, different reserve engineers may make different estimates of reserves and cash flows based on the same available data. The present value of future net revenues from our proved reserves referred to in this Report is not necessarily the actual current market value of our estimated oil and natural gas reserves. In accordance with SEC requirements, we base the estimated discounted future net cash flows from our proved reserves on fixed prices and costs as of the date of the estimate. Actual future prices and costs fluctuate over time and may differ materially from those used in the present value estimate. In addition, discounted future net cash flows are estimated assuming royalties to the MMS, royalty owners and other state and federal regulatory agencies with respect to our affected properties, and will be paid or suspended during the life of the properties based upon oil and natural gas prices as of the date of the estimate. Since actual future prices fluctuate over time, royalties may be required to be paid for various portions of the life of the properties and suspended for other portions of the life of the properties.

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The timing of both the production and expenses from the development and production of oil and natural gas properties will affect both the timing of actual future net cash flows from our proved reserves and their present value. In addition, the 10% discount factor that we use to calculate the net present value of future net cash flows for reporting purposes in accordance with the SEC's rules may not necessarily be the most appropriate discount factor. The effective interest rate at various times and the risks associated with our business or the oil and natural gas industry, in general, will affect the appropriateness of the 10% discount factor in arriving at an accurate net present value of future net cash flows.

***We are subject to the full cost ceiling limitation which may result in a write-down of our estimated net reserves.***

Under the full cost method, we are subject to quarterly calculations of a "ceiling" or limitation on the amount of our oil and gas properties that can be capitalized on our balance sheet. If the net capitalized costs of our oil and gas properties exceed the cost center ceiling, we are subject to a ceiling test write-down of our estimated net reserves to the extent of such excess. If required, it would reduce earnings and impact stockholders' equity in the period of occurrence and result in lower amortization expense in future periods. The discounted present value of our proved reserves is a major component of the ceiling calculation and represents the component that requires the most subjective judgments. However, the associated hedge adjusted market prices of oil and gas reserves that are included in the discounted present value of the reserves do not require judgment. The ceiling calculation dictates that prices and costs in effect as of the last day of the quarter are held constant. However, we may not be subject to a write-down if prices increase subsequent to the end of a quarter in which a write-down might otherwise be required. The risk that we will be required to write down the carrying value of oil and natural gas properties increases when natural gas and crude oil prices are depressed or volatile. In addition, write-down of proved oil and natural gas properties may occur if we experience substantial downward adjustments to our estimated proved reserves or if purchasers cancel long-term contracts for our natural gas production. As expense recorded in one period may not be reversed in a subsequent period event though higher natural gas and crude oil prices may have increased the ceiling applicable in the subsequent period.

***We are subject to complex government regulation that could adversely affect our operations.***

Our activities are subject to complex and stringent environmental and other governmental laws and regulations. The exploration and production of oil and natural gas requires numerous permits, approvals and certificates from appropriate federal, state and local governmental agencies, including state and local agencies in California, whose regulations typically are more stringent than in other states or localities, as well as compliance with environmental protection legislation and other regulations. We remain subject to a varied and complex body of laws and regulations that both public officials and private individuals may seek to enforce. Existing laws and regulations are routinely revised or reinterpreted, and together with new laws and regulations may impact us and have a negative effect on our business and results of operations. We may be unable to obtain all necessary licenses, permits, approvals and certificates for proposed projects. Intricate and changing environmental and other regulatory requirements may necessitate substantial expenditures to obtain and maintain permits. If a project is unable to function as planned due to changing requirements or local opposition, it may create expensive delays, extended periods of non-operation or significant loss of value in a project.

Our business is subject to federal, state and local laws and regulations as interpreted by governmental agencies and other bodies, including those in California, vested with authority over the exploration, development, production and transportation of oil and natural gas, including environmental and safety matters. Existing laws and regulations are routinely changed which could increase costs of compliance and costs of operating drilling equipment, or otherwise significantly limit drilling activity.

Under certain circumstances, the MMS may require that our operations on federal leases be suspended or terminated. These circumstances include our failure to pay royalties or our failure to comply with safety and environmental regulations. The requirements imposed by these laws and regulations are frequently changed and subject to new interpretations, and if such were to occur, could negatively impact our results of operations and cash flows.

***Our business requires technical expertise, specialized knowledge and training and a high degree of management experience.***

Our success is largely dependent on the skills, experience and efforts of our employees. The loss of the services of one or more members of our senior management or of numerous employees with critical skills could have a negative effect on our business, financial conditions and results of operations and future growth.

***Our results are subject to commodity price fluctuations related to seasonal and market conditions and reservoir and production risks.***

Our quarterly operating results have fluctuated in the past and could be negatively impacted in the future as a result of a number of factors, including:

- Seasonal variations in oil and natural gas prices;
- Variations in levels of production; and
- The completion of exploration and production projects.

***The ultimate outcome of the legal proceedings relating to our activities cannot be predicted. Any adverse determination could have a material adverse effect on our financial condition, results of operations or cash flows.***

Operation of our properties has generated various litigation matters arising out of the normal course of business. In connection with the transfer and assumption agreement with Calpine, we generally assumed liabilities arising from our activities from and after the Acquisition, including defense of future litigation and claims involving Calpine's domestic oil and natural gas reserve properties conveyed in the Acquisition, other than certain litigation that Calpine and its subsidiaries retained liability or agreed to indemnify the Company by agreement. Calpine's bankruptcy may affect its obligations for the retained liabilities and claims. The ultimate outcome of claims and litigation relating to our activities cannot presently be determined, nor can the liability that may potentially result from a negative outcome be reasonably estimated at this time for every case. The liability we may ultimately incur with respect to any one of these matters in the event of a negative outcome may be in excess of amounts currently accrued with respect to such matters and, as a result, these matters may potentially be material to our financial condition, results of operations or cash flows.

***Market conditions or transportation impediments may hinder our access to oil and natural gas markets or delay our production.***

Market conditions, the unavailability of satisfactory oil and natural gas processing and transportation or the remote location of certain of our drilling operations may hinder our access to oil and natural gas markets or delay our production. The availability of a ready market for our oil and natural gas production depends on a number of factors, including the demand for and supply of oil and natural gas and the proximity of reserves to pipelines or trucking and terminal facilities. In the Gulf of Mexico operations, the availability of a ready market depends on the proximity of and our ability to tie into existing production platforms owned or operated by others and the ability to negotiate commercially satisfactory arrangements with the owners or operators. We may be required to shut in natural gas wells or delay initial production for lack of a market or because of inadequacy or unavailability of natural gas pipelines or gathering system capacity. When that occurs, we are unable to realize revenue from those wells until the production can be tied to a gathering system. This can result in considerable delays from the initial discovery of a reservoir to the actual production of the oil and natural gas and realization of revenues.

***Competition in the oil and natural gas industry is intense, and many of our competitors have resources that are greater than ours.***

We operate in a highly competitive environment for acquiring prospects and productive properties, marketing oil and natural gas and securing equipment and trained personnel. Many of our competitors, major and large independent oil and natural gas companies, possess and employ financial, technical and personnel resources substantially greater than our resources. Those companies may be able to develop and acquire more prospects and productive properties than our financial or personnel resources permit. Our ability to acquire additional prospects and discover reserves in the future will depend on our ability to evaluate and select suitable properties and consummate transactions in a highly competitive environment. Also, there is substantial competition for capital available for investment in the oil and natural gas industry. Larger competitors may be better able to withstand sustained periods of unsuccessful drilling and absorb the burden of changes in laws and regulations more easily than we can, which would adversely affect our competitive position. We may not be able to compete successfully in the future in acquiring prospective reserves, developing reserves, marketing hydrocarbons, attracting and retaining quality personnel and raising additional capital.

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***Operating hazards, natural disasters or other interruptions of our operations could result in potential liabilities, which may not be fully covered by our insurance.***

The oil and natural gas business involves certain operating hazards such as:

- Well blowouts;
- Cratering;
- Explosions;
- Uncontrollable flows of oil, natural gas or well fluids;
- Fires;
- Hurricanes, tropical storms, earthquakes, mud slides, and flooding;
- Pollution; and
- Releases of toxic gas.

The occurrence of one of the above may result in injury, loss of life, property damage, suspension of operations, environmental damage and remediation and/or governmental investigations and penalties.

In addition, our operations in California are especially susceptible to damage from natural disasters such as earthquakes and fires and involve increased risks of personal injury, property damage and marketing interruptions. Any of these operating hazards could cause serious injuries, fatalities or property damage, which could expose us to liabilities. The payment of any of these liabilities could reduce, or even eliminate, the funds available for exploration, development, and acquisition, or could result in a loss of our properties. Our insurance policies provide limited coverage for losses or liabilities relating to pollution, with broader coverage for sudden and accidental occurrences. Our insurance might be inadequate to cover our liabilities. For example, we are not fully insured against earthquake risk in California because of high premium costs. Insurance covering earthquakes or other risks may not be available at premium levels that justify its purchase in the future, if at all. In addition, we are subject to energy package insurance coverage limitations related to any single named windstorm. The insurance market in general and the energy insurance market in particular have been difficult markets over the past several years. Insurance costs are expected to continue to increase over the next few years and we may decrease coverage and retain more risk to mitigate future cost increases. If we incur substantial liability and the damages are not covered by insurance or are in excess of policy limits, or if we incur a liability at a time when we are not able to obtain liability insurance, then our business, results of operations, financial condition, and cash flows could be materially adversely affected. Because of the expense of the associated premiums and the perception of risk, we do not have any insurance coverage for any loss of production as may be associated with these operating hazards.

***Environmental, health, and safety liabilities could adversely affect our financial condition.***

The oil and natural gas business is subject to environmental, health and safety hazards, such as oil spills, natural gas leaks and ruptures and discharges of petroleum products and hazardous substances, and historic disposal activities. These hazards could expose us to material liabilities for property damages, personal injuries or other environmental, health and safety harms, including costs of investigating and remediating contaminated properties. In addition, we also may be liable for environmental damages caused by the previous owners or operators of properties we have purchased or are currently operating. A variety of federal, state and local laws and regulations govern the environmental aspects of our business and impose strict requirements for, among other things:

- Well drilling or workover, operation and abandonment;
- Waste management;
- Land reclamation;
- Financial assurance under the Oil Pollution Act of 1990; and
- Controlling air, water and waste emissions.

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Any noncompliance with these laws and regulations could subject us to material administrative, civil or criminal penalties or other liabilities. Additionally, our compliance with these laws may, from time to time, result in increased costs to our operations or decreased production, and may affect our costs of acquisitions. We are unable to predict the ultimate cost of complying with these regulations.

In addition, environmental laws may, in the future, cause a decrease in our production or cause an increase in our costs of production, development or exploration. Pollution and similar environmental risks generally are not fully insurable.

Some of our California properties have been in operation for a substantial length of time, and current or future local, state and federal environmental and other laws and regulations may require substantial expenditures to remediate the properties or to otherwise comply with these laws and regulations. A variety of existing laws, rules and guidelines govern activities that can be conducted on our properties and other existing or future laws, rules and guidelines could prohibit or limit our operations and our planned activities for properties.

Under our Purchase Agreement with Calpine, other than certain retained claims, we are responsible for environmental claims prior to the Acquisition and we may not have indemnification from Calpine related to those claims.

***Our acquisition strategy could fail or present unanticipated problems for our business in the future, which could adversely affect our ability to make acquisitions or realize anticipated benefits of those acquisitions.***

Our growth strategy includes acquiring oil and natural gas businesses and properties if favorable economics and strategic objectives can be served. We may not be able to identify suitable acquisition opportunities or finance and complete any particular acquisition successfully.

Furthermore, acquisitions involve a number of risks and challenges, including:

- Division of management’s attention;
- The need to integrate acquired operations;
- Potential loss of key employees of the acquired companies;
- Potential lack of operating experience in a geographic market of the acquired business; and
- An increase in our expenses and working capital requirements.

Any of these factors could adversely affect our ability to achieve anticipated levels of cash flows from the acquired businesses and properties or realize other anticipated benefits of those acquisitions.

***We are vulnerable to risks associated with operating in the Gulf of Mexico.***

Our operations and financial results could be significantly impacted by conditions in the Gulf of Mexico because we explore and produce extensively in that area. As a result of this activity, we are vulnerable to the risks associated with operating in the Gulf of Mexico, including those relating to:

- Adverse weather conditions and natural disasters;
- Oil field service costs and availability;
- Compliance with environmental and other laws and regulations;
- Remediation and other costs resulting from oil spills or releases of hazardous materials; and
- Failure of equipment or facilities.

Further, production of reserves from reservoirs in the Gulf of Mexico generally decline more rapidly than from fields in many other producing regions of the world. This results in recovery of a relatively higher percentage of reserves from properties in the Gulf of Mexico during the initial years of production, and as a result, our reserve replacement needs from new prospects may be greater there than for our operations elsewhere. Also, our revenues and return on capital will depend significantly on prices prevailing during these relatively short production periods.

***Hedging transactions may limit our potential gains.***

We have entered into natural gas price hedging arrangements with respect to a significant portion of our expected production through 2009. Such transactions may limit our potential gains if oil and natural gas prices were to rise substantially over the price established by the hedge. In addition, such transactions may expose us to the risk of loss in certain circumstances, including instances in which our production is less than expected, there is a widening of price differentials between delivery points for our production and the delivery point assumed in the hedge arrangement, or the counterparties to our hedging agreements fail to perform under the contracts.

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***The historical financial results of the domestic oil and natural gas business of Calpine may not be representative of our results as a separate company.***

The combined historical financial information included in this report does not necessarily reflect what our financial position, results of operations and cash flows would have been had we been a separate, stand-alone entity during the periods presented. The costs and expenses reflect charges from Calpine for centralized corporate services and infrastructure costs. The allocations were determined based on Calpine's methodologies. This combined historical financial information is not necessarily indicative of what our results of operations, financial position and cash flows will be in the future.

***Failure to achieve and maintain effective internal control over financial reporting in accordance with the rules of the SEC could harm our business.***

Under current rules of the SEC, as of December 31, 2007, we will be required to document and test our internal control over financial reporting so that our management can certify as to the effectiveness of our internal control over financial reporting and our independent registered public accounting firm can render an opinion on management's assessment. We cannot be certain as to the timing of completion of our evaluation, testing and remediation actions, if any, or the impact of the same on our operations. The assessment of our internal control over financial reporting will require us to expend significant management and employee time and resources and incur significant additional expense.

We have begun the process of evaluating and documenting our internal control over financial reporting in order to test and determine whether any remediation actions may be necessary to fully implement the requirements relating to internal controls and all other aspects of related SEC rules and the Sarbanes Oxley Act of 2002. Management believes it has remediated the material weaknesses noted as of December 31, 2005: (1) lack of a sufficient complement of permanent personnel to have an appropriate accounting and financial reporting structure to support the activities of the Company and (2) ineffective controls as related to the identification and documentation of accounting policies, including selection and application of generally accepted accounting principles used for accounting for select transactions and other activities; however, see Item 9A. Controls and Procedures, for a further discussion on these material weaknesses.

Although we expect to fully implement the requirements to meet the required SEC and Sarbanes-Oxley standards in 2007, our efforts may not be successful and additional deficiencies or weaknesses in our internal controls and procedures may be identified.

***Our prior and continuing relationship with Calpine exposes us to risks attributable to Calpine's businesses and credit worthiness.***

We acquired a business that previously was integrated within Calpine and is subject to liabilities and risk for activities of businesses of Calpine other than the acquired business. In connection with our separation from Calpine, Calpine and certain of its subsidiaries have agreed to retain and indemnify us for certain liabilities. Third parties may seek to hold us responsible for some or all of those retained liabilities.

Any claims made against us that are properly attributable to Calpine and certain of its subsidiaries will require us to exercise our rights under the indemnification provisions of the purchase and sale agreement to obtain payment from them. We are exposed to the risk that, in these circumstances and in light of the Calpine bankruptcy, any or all of Calpine and certain of its subsidiaries cannot or will not make the required payment. If this were to occur, our business and results of operations, financial position or cash flow could be adversely affected.

***If we are unable to obtain governmental approvals arising from the Acquisition, we may not acquire all of Calpine's domestic oil and gas business.***

The consummation of the Acquisition required various approvals, filings and recordings with governmental entities to transfer existing contracts and arrangements as well as all of Calpine's domestic oil and gas properties to us. In addition, all government issued permits and licenses that are important to our business, including permits issued by the City of Rio Vista and Counties of Sacramento, Solano and Contra Costa, California, may require reapplication or application by us and reissuance or issuance in our name. Some of the required permits, licenses and approvals have been obtained or received, but certain others remain outstanding. If we are unable to obtain a reissuance or issuance of any contract, license or permit being transferred or the required approvals as operator and/or lessee, as to certain oil and gas properties, our business and results of operations, financial position and cash flow could be adversely affected.

***The SEC informal inquiry relating to the downward revision of the estimate of continuing proved reserves, while owned by Calpine, could have a material adverse effect on the presentation of our predecessor financial statements.***

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In April 2005, the staff of the Division of Enforcement of the SEC commenced an informal inquiry into the facts and circumstances relating to the downward revision of the estimate of continuing proved natural gas reserves at December 31, 2004, while the domestic oil and natural gas properties were owned by Calpine. Calpine has advised us that it is fully cooperating with this informal inquiry which also involved two other non-oil and natural gas related matters, and we have separately agreed with Calpine that we will also fully cooperate. Calpine has advised us that it has not had any further response or inquiry from the SEC staff in regard to this matter since July 2005 and that the ultimate outcome of this inquiry cannot presently be determined. However, it is possible that the staff of the SEC could conclude that the estimate of continuing proved reserves as of December 31, 2004, as revised, requires further downward revision, which could have a material adverse effect on the presentation of our predecessor financial statements.

***Future sales of our common stock may cause our stock price to decline.***

Sales of substantial amounts of our common stock in the public market, or the perception that these sales may occur, could cause the market price of our common stock to decline, which could impair our ability to raise capital through the sale of additional common or preferred stock.

***Stock sales and purchases by institutional investors or stockholders with significant holdings could have significant influence over our stock volatility and our corresponding ability to raise capital through debt or equity offerings.***

Because institutional investors have the ability to trade in large volumes of shares of our common stock, the price of our common stock could be subject to significant volatility, which could adversely affect the market price for our common stock as well as limit our ability to raise capital or issue additional equity in the future.

***You may experience dilution of your ownership interests because of the future issuance of additional shares of our common and preferred stock.***

We may in the future issue our previously authorized and unissued equity securities, resulting in the dilution of the ownership interests of our present stockholders and purchasers of common stock offered hereby. We are currently authorized to issue an aggregate of 155,000,000 shares of capital stock consisting of 150,000,000 shares of common stock and 5,000,000 shares of preferred stock with preferences and rights as determined by our Board of Directors. As of December 31, 2006, 50,732,694 shares of common stock were issued, including 673,875 shares of restricted stock issued to certain employees and directors. The majority of these vest over a three year period. Of the restricted stock that has been granted, 346,975 shares had vested as of December 31, 2006 and the remaining shares will vest on a three year period ending in 2009. Pursuant to our 2005 Long-Term Incentive Plan, we have reserved 3,000,000 shares of our common stock for issuance as restricted stock, stock options and/or other equity based grants to employees and directors. Of the reserved shares, 1,233,333 may be awarded as restricted stock and 1,766,667 may be awarded as stock options and/or other equity based grants and includes 903,250 options to purchase common stock issued to certain employees and directors, of which 50,396 have been exercised as of December 31, 2006. The potential issuance of such additional shares of common stock may create downward pressure on the trading price of our common stock. We may also issue additional shares of our common stock or other securities that are convertible into or exercisable for common stock in connection with the hiring of personnel, future acquisitions, future issuance of our securities for capital raising purposes, or for other business purposes.

***Provisions under Delaware law, our certificate of incorporation and bylaws could delay or prevent a change in control of our company, which could adversely affect the price of our common stock.***

The existence of some provisions under Delaware law, our certificate of incorporation and bylaws could delay or prevent a change in control of the Company, which could adversely affect the price of our common stock. Delaware law imposes restrictions on mergers and other business combinations between us and any holder of 15% or more of our outstanding common stock. Our certificate of incorporation and bylaws prohibit our stockholders from taking action by written consent absent approval by all members of our Board of Directors. Further, our stockholders do not have the power to call a special meeting of stockholders.

**Item 1B. Unresolved Staff Comments**

None

**Item 2. Properties**

A description of our properties is located in Item 1. Business and is incorporated herein by reference.

Our headquarters are located at 717 Texas, Suite 2800, Houston, Texas 77002, where we sublease two floors of office space from Calpine. We also maintain a division office in Denver, Colorado, where we were assigned a lease by Calpine and consequently deal directly with the landlord. We also have field offices in Laredo, Texas and Rio Vista, California. All leases were negotiated at market prices applicable to their respective location.

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***Title to Properties***

Our properties are subject to customary royalty interests, liens incident to operating agreements, liens for current taxes and other burdens, including other mineral encumbrances and restrictions as well as mortgage liens on at least 80% of our proved reserves in accordance with our credit facilities. We do not believe that any of these burdens materially interferes with our use of the properties in the operation of our business.

Except as noted in the "Transfers of Legal Title Pending at Calpine's Bankruptcy" section in Item 3. Legal Proceedings, we believe that we have generally satisfactory title to or rights in all of our producing properties. As is customary in the oil and natural gas industry, we make minimal investigation of title at the time we acquire undeveloped properties. We make title investigations and receive title opinions of local counsel only before we commence drilling operations. We believe that we have satisfactory title to all of our other assets. Although title to our properties is subject to encumbrances in certain cases, we believe that none of these burdens will materially detract from the value of our properties or from our interest therein or will materially interfere with our use in the operation of our business.

Calpine's recent bankruptcy may delay or frustrate our ability to complete additional transfers of properties for which legal title were not obtained as of July 7, 2005.

**Item 3. Legal Proceedings**

We are party to various oil and natural gas litigation matters arising out of the ordinary course of business. While the outcome of these proceedings cannot be predicted with certainty, we do not expect these matters to have a material adverse effect on the financial statements.

We carry insurance with coverage and coverage limits consistent with our assessment of risks in our business and of an acceptable level of financial exposure. Although there can be no assurance that such insurance will be sufficient to mitigate all damages, claims or contingencies, we believe that our insurance provides reasonable coverage for known asserted or unasserted claims. In the event we sustain a loss from a claim and the insurance carrier disputed coverage or coverage limits, we may record a charge in a different period than the recovery, if any, from the insurance carrier.

***Calpine Bankruptcy***

Calpine Corporation and certain of its subsidiaries filed for protection under the federal bankruptcy laws in the Bankruptcy Court on December 20, 2005. Calpine Energy Services, L.P., which filed for bankruptcy, has continued to make the required deposits into the Company's margin account and to timely pay for natural gas production it purchases from the Company's subsidiaries under various natural gas supply agreements. As part of the Acquisition, Calpine and the Company entered into a Transition Services Agreement, pursuant to which both parties were to provide certain services for the other for various periods of time. Calpine's obligation to provide services under the Transition Services Agreement ceased on July 6, 2006 and certain of Calpine's services ceased prior to the conclusion of the contract, which in neither case had any material effect on the Company. Additionally, Calpine Producer Services, L.P., which filed for bankruptcy, generally is performing its obligations under the Marketing and Services Agreement ("MSA") with the Company. The MSA was entered into by the Company and Calpine in July 2005 for the period through June 30, 2007.

The filing raises certain concerns regarding aspects of our relationship with Calpine which we will closely monitor as the Calpine bankruptcy proceeds. See further discussion of our concerns under Item 1A. Risk Factors.

**Transfers of Legal Title Pending at Calpine's Bankruptcy**

At the closing of the Acquisition on July 7, 2005, we retained approximately $75 million of the purchase price in respect to Non-Consent Properties identified by Calpine at the time of the Acquisition as requiring third party consents or waivers of preferential rights to purchase that were not received before closing. Legal title for those Non-Consent Properties was not delivered at the closing. Subsequent analysis determined that a portion of the Non-Consent Properties, with an approximate allocation value of $29 million under the Purchase Agreement did not require consents or waivers. For that portion of the Non-Consent Properties for which third party consents were in fact required (having an approximate value of $39 million under the Purchase Agreement) and for which we obtained the required consents or waivers, as well as for all Non-Consent Properties that did not require consents or waivers, we believe that Calpine was and is obligated to have transferred to us the record legal title, free of any mortgages and other liens.

The approximate allocated value under the Purchase Agreement for the portion of the Non-Consent Properties subject to a third party's preferential right to purchase is $7.4 million. We have retained $7.1 million of the purchase price under the Purchase Agreement for the Non-Consent Properties subject to a third party's preferential right to purchase, and, in addition, a post-closing adjustment is required to credit us for approximately $0.3 million for a property which was transferred to us but will be transferred to the appropriate third party should it properly exercise its preferential purchase right and upon Calpine's performance of its remaining obligations under the Purchase Agreement.

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We believe all conditions precedent for our receipt of record title, free of any mortgages or other liens, for substantially all of the Non-Consent Properties (excluding that portion of these properties for which a third party's preferential right to purchase was properly exercised) were satisfied earlier, and certainly no later than December 15, 2005, when we tendered once again the amounts necessary to conclude the settlement of the Non-Consent Properties.

We believe we are the equitable owner of each of the Non-Consent Properties for which Calpine was and is obligated to have transferred to us the record legal title and that such properties are not part of Calpine's bankruptcy estate. Upon our receipt from Calpine of record legal title, free of any mortgages or other liens, to these Non-Consent Properties and Calpine's performance or its further assurances required to eliminate any open issues on title to the remaining properties discussed below, we are prepared to pay Calpine approximately $68 million, subject to appropriate adjustment for the associated net revenues and expenses through December 15, 2005 and performance of Calpine's obligations under the "further assurances" provisions of the Purchase and Sale Agreement. Our statement of operations for the year ended December 31, 2006 and six months ended December 31, 2005 does not include any net revenues or production from any of the Non-Consent Properties, or those properties subject to preferential rights.

If Calpine does not provide us with record legal title, free of any mortgages for all of these properties and other liens, to any of the Non-Consent Properties (excluding that portion of these properties subject to a validly exercised third party's preferential right to purchase), we will have a total of approximately $68 million available to us for general corporate purposes, including for the purpose of acquiring additional properties. We also have approximately $7.1 million, previously withheld for that portion of the Non-Consent Properties subject to a third party's preferential right to purchase, which will also be available to us for general corporate purposes, including for the purpose of acquiring additional properties should that third party properly exercise their preferential rights.

In addition, as to certain of the other oil and natural gas properties we purchased from Calpine in the Acquisition and for which payment was made on July 7, 2005, we will seek additional documentation from Calpine to eliminate any open issues in our title or resolve any issues as to the clarity of our ownership. Requests for additional documentation are customary in connection with transactions similar to the Acquisition. In the Acquisition, certain of these properties require ministerial governmental action approving us as qualified assignee and operator, which is typically required even though in most cases Calpine has already conveyed the properties to us free and clear of mortgages and liens by Calpine's creditors. As to certain other properties, the documentation delivered by Calpine at closing under the Purchase Agreement was incomplete. We remain hopeful that Calpine will work cooperatively with us to secure these ministerial governmental approvals and to accomplish the curative corrections for all of these properties. In addition, as to all properties acquired by us in the Acquisition, Calpine contractually agreed to provide us with such further assurances as we may reasonably request. Nevertheless, as a result of Calpine's bankruptcy filing, it remains uncertain as to whether Calpine will respond cooperatively. If Calpine does not fulfill its contractual obligations and does not complete the documentation necessary to resolve these issues, we will pursue all available remedies, including but not limited to a declaratory judgment to enforce our rights and actions to quiet title. After pursuing these matters, if we experience a loss of ownership with respect to these properties without receiving adequate consideration for any resulting loss to us, an outcome our management considers to be remote, then we could experience losses which could have a material adverse effect on our financial condition, statement of operations and cash flows.

On June 29, 2006, Calpine filed a motion in connection with its pending bankruptcy proceeding in the Bankruptcy Court seeking the entry of an order authorizing Calpine to assume certain oil and natural gas leases Calpine has previously sold or agreed to sell to us in the Acquisition, to the extent those leases constitute "unexpired leases of non-residential real property" and were not fully transferred to us at the time of Calpine's filing for bankruptcy. According to this motion, Calpine filed it in order to avoid the automatic forfeiture of any interest it may have in these leases by operation of a statutory deadline. Calpine's motion did not request that the Bankruptcy Court determine whether these properties belong to us or Calpine, but we understand it was meant to allow Calpine to preserve and avoid forfeiture under the Bankruptcy Code of whatever interest Calpine may possess, if any, in these oil and natural gas leases. We dispute Calpine's contention that it may have an interest in any significant portion of these oil and natural gas leases and intend to take the necessary steps to protect all of our rights and interest in and to the leases. On July 7, 2006, we filed an objection in response to Calpine's motion, wherein we asserted that oil and natural gas leases constitute interests in real property that are not subject to "assumption" under the Bankruptcy Code. In the objection we also requested that (a) the Bankruptcy Court eliminate from the order certain Federal offshore leases from the Calpine motion because these properties were fully conveyed to us in July 2005, and the Minerals Management Service has subsequently recognized us as owner and operator of all but three of these properties, and (b) any order entered by the Bankruptcy Court be without prejudice to, and fully preserve our rights, claims and legal arguments regarding the characterization and ultimate disposition of the remaining described oil and natural gas properties. In our objection, we also urged the Bankruptcy Court to require the parties to promptly address and resolve any remaining issues under the pre-bankruptcy definitive agreements with Calpine and proposed to the Bankruptcy Court that the parties seek arbitration (or at least mediation) to complete the following:

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- Calpine's conveyance of the Non-Consent Properties to us;
- Calpine's execution of all documents and performance of all tasks required under "further assurances" provisions of the Purchase Agreement with respect to certain of the oil and natural gas properties for which we have already paid Calpine; and
- Resolution of the final amounts we are to pay Calpine, which we have concluded are approximately $79 million, consisting of roughly $68 million for the Non-Consent Properties and approximately $11 million in other true-up payment obligations.

At a hearing held on July 12, 2006, the Bankruptcy Court took the following steps:

- In response to an objection filed by the Department of Justice and asserted by the California State Lands Commission that the Debtors' Motion to Assume Non-Residential Leases and Set Cure Amounts (the "Motion"), did not allow adequate time for an appropriate response, Calpine withdrew from the list of Oil and Gas Leases that were the subject of the Motion those leases issued by the United States (and managed by the Minerals Management Service of the United States Department of Interior) (the "MMS Oil and Gas Leases") and the State of California (and managed by the California State Lands Commission) (the "CSLC Leases"). Calpine and both the Department of Justice and the State of California agreed to an extension of the existing deadline to November 15, 2006 to assume or reject the MMS Oil and Gas Leases and CSLC Leases under Section 365 of the Bankruptcy Code, to the extent the MMS Oil and Gas Leases and CSLC Leases are leases subject to Section 365. The effect of these actions was to render our objection inapplicable at that time; and
- The Bankruptcy Court also encouraged Calpine and us to arrive at a business solution to all remaining issues including approximately $68 million payable to Calpine for conveyance of the Non-Consent Properties.

On August 1, 2006, we filed a number of proofs of claim in the Calpine bankruptcy asserting claims against a variety of Calpine debtors seeking recovery of $27.9 million in liquidated amounts as well as unliquidated damages in amounts that can not presently be determined. We continue to work with Calpine on a cooperative and expedited basis toward resolution of unresolved conveyance of properties and post-closing adjustments under the Purchase Agreement.

With respect to the stipulations between Calpine and MMS and Calpine and CSLC extending the deadline to assume or reject the MMS Oil and Gas Leases, these parties have further extended this deadline time by stipulation. The deadline was first extended to January 31, 2007 and recently was further extended to April 15, 2007 with respect to the MMS Oil and Gas Leases and April 30, 2007 with respect to the CSLC Leases. The Bankruptcy Court entered Orders related to the MMS Oil and Gas Leases and CSLC Leases which included appropriate language that we negotiated with Calpine for our protection in this regard.

Recently, Calpine sought and obtained an extension to June 20, 2007 from the Bankruptcy Court for the period in which only Calpine, exclusively, may file its plan of reorganization. While there is no assurance that Calpine will file a plan of reorganization by the deadline, or that such a plan will be approved by the creditors and the Bankruptcy Court, we remain optimistic that the issues involving conclusion of the remaining conveyances of the Non-Consent Properties and obtaining the further assurances from Calpine under the Purchase Agreement, including perhaps resolution of any and all claims, may occur during 2007.

Calpine recently requested Bankruptcy Court approval of a new credit facility which would require it to grant liens to these new lenders in all of its assets, including any interest it may still hold in any oil and gas properties it obligated itself to convey to us under the Purchase Agreement. The Bankruptcy Court entered into an Order approving Calpine's ability to obtain this new loan which includes appropriate language that we negotiated with Calpine for our protection in this regard.

However, there can be no assurance that Calpine, its creditors or other interest holders will not challenge the fairness of the Acquisition. For a number of reasons, including our understanding of the process that Calpine followed in allowing market forces to set the purchase price for the Acquisition, we continue to believe that it is unlikely that any challenges by the Calpine debtors or their creditors to the overall fairness of the Acquisition would be successful. We will take all necessary action to ensure our rights under the Purchase Agreement, the MMS Oil and Gas Leases, the CSLC Leases and the Bankruptcy Code are fully protected.

**Item 4. Submission of Matters to a Vote of Security Holders**

No matters were submitted to a vote of our security holders during the fourth quarter of 2006.

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## Part II

### Item 5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

***Trading Market***

Our common stock is listed on The NASDAQ Global Select Market® under the symbol "ROSE". Our common stock began publicly trading on February 13, 2006. Prior to such date, there was no public market for our common stock. However, certain qualified institutional investors participated in limited trading through quotes on The PORTAL Market after July 7, 2005.

The following table sets forth for the 2006 periods indicated the high and low sale prices of our common stock:

| | High | Low |
|---|---|---|
| February 13 - March 31 | $ 18.75 | $ 17.67 |
| April 1 - June 30 | 21.48 | 15.81 |
| July 1 - September 30 | 19.05 | 15.82 |
| October 1 - December 31 | 19.89 | 16.71 |

The number of shareholders on March 5, 2007 was 13,444. However, we estimate that we have a significantly greater number of beneficial shareholders because a substantial number of our common shares are held of record by brokers or dealers for the benefit of their customers.

We have not paid a cash dividend on our common stock and currently intend to retain earnings to fund the growth and development of our business. Any future change in our policy will be made at the discretion of our board of directors in light of the financial condition, capital requirements, earnings prospects of Rosetta and any limitations imposed by lenders or investors, as well as other factors the board of directors may deem relevant.

The following table sets forth certain information with respect to repurchases of our common stock during the three months ended December 31, 2006:

| Period | Total Number of Shares Purchased (1) | Average Price Paid per Share | Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs | Maximum Number (or Approximate Dollar Value) of Shares that May yet Be Purchased Under the Plans or Programs |
|---|---|---|---|---|
| October 1 - October 31 | 945 | $ 17.93 | - | - |
| November 1 - November 30 | 962 | 19.15 | - | - |
| December 1 - December 31 | - | - | - | - |

(1)

All of the shares were surrendered by the employees to pay tax withholding upon the vesting of restricted stock awards. These repurchases were not part of a publicly announced program to repurchase shares of our common stock, nor do we have a publicly announced program to repurchase shares of common stock.

***Stock Performance Graph***

The following graph compares our common stock performance (“ROSE”) with the performance of the Standard & Poors’ 500 Stock Index (“S&P 500 Index”) and the performance of our peers within the oil and gas industry. The seven companies that comprise our peer group are Petrohawk Energy Corporation (HAWK), St. Mary Land & Exploration Co. (SM), Bill Barrett Corp. (BBG), Brigham Exploration Co. (BEXP), Berry Petroleum Co. (BRY), Comstock Resources Inc. (CRK) and Range Resources Corp. (RRC), (“Peer Group”). The graph assumes the value of the investment in our common stock , the S&P 500 Index, and our Peer Group was $100 on February 13, 2006 and that all dividends are reinvested.

*The performance graph shall not be deemed incorporated by reference by any general statement incorporating by reference this Annual Report into any filing under the Securities Act of 1933, except to the extent we specifically incorporate this information by reference and shall not otherwise be deemed filed under such acts.*

**Total Return Among Rosetta Resources, Inc., the S&P 500 Index and our Peer Group**

| | | **2/13/2006 (1)** | | **12/31/2006** |
|---|---|---|---|---|
| ROSE | $ | 100.00 | $ | 98.26 |
| S&P 500 Index | $ | 100.00 | $ | 111.94 |
| Peer Group | $ | 100.00 | $ | 94.82 |

(1) February 13, 2006 was the first full trading day following the effective date of the Company’s registration statement filed in connection with the public offering of its common stock.

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**Item 6. Selected Financial Data**

The following table sets forth our selected financial data. For the year ended December 31, 2006 (Successor) and the six months ended December 31, 2005 (Successor), the financial data has been derived from the consolidated financial statements of Rosetta Resources Inc. For the six months ended June 30, 2005 (Predecessor) and for the years ended December 31, 2004, 2003 and 2002 (Predecessor), the financial data was derived from the combined financial statements of the domestic oil and natural gas properties of Calpine and are presented on a carve-out basis to include the historical operations of the domestic oil and natural gas business. You should read the following selected historical consolidated/combined financial data in connection with "Management's Discussion and Analysis of Financial Condition and Results of Operation" and the audited Consolidated/Combined Financial Statements and related notes included elsewhere in this report.

Additionally, the historical financial data reflects successful efforts accounting for oil and natural gas properties for the Predecessor periods described above and the full cost method of accounting for oil and natural gas properties effective July 1, 2005 for the Successor periods. In addition, Calpine adopted on January 1, 2003, SFAS No. 123, "Accounting for Stock-Based Compensation", as amended by SFAS No. 148, "Accounting for Stock-Based Compensation—Transition and Disclosure" (SFAS No. 123") to measure the cost of employee services received in exchange for an award of equity instruments, whereas we adopted the intrinsic value method of accounting for stock options and stock awards pursuant to Accounting Principles Board Opinion No. 25, "Stock Issued to Employees" ("APB No. 25") effective July 2005, and as required have adopted the guidance for stock-based compensation under SFAS No. 123 (revised 2004) "Share-Based Payments" ("SFAS No. 123R") effective January 1, 2006.

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| | Successor-Consolidated | | Predecessor - Combined | | | |
|---|---|---|---|---|---|---|
| | Year Ended December 31, 2006 | Six Months Ended December 31, 2005 | Six Months Ended June 30, 2005 | Year Ended December 31, 2004 | 2003 | 2002 |
| | (In thousands, except per share data) | | | | | |
| **Operating Data:** | | | | | | |
| Total revenue | $ 271,763 | $ 113,104 | $ 103,831 | $ 248,006 | $ 279,916 | $ 157,372 |
| Income (loss) from continuing operations (1) | 44,608 | 17,535 | 18,681 | (78,836) | 66,879 | 1,484 |
| Net income (loss) | 44,608 | 17,535 | 18,681 | (10,396) | 71,440 | (168) |
| **Income per share:** | | | | | | |
| Income (loss) from continuing operations | | | | | | |
| Basic | 0.89 | 0.35 | 0.37 | (1.58) | 1.34 | 0.03 |
| Diluted | 0.88 | 0.35 | 0.37 | (1.58) | 1.33 | 0.03 |
| Net income (loss) | | | | | | |
| Basic | 0.89 | 0.35 | 0.37 | (0.21) | 1.43 | - |
| Diluted | 0.88 | 0.35 | 0.37 | (0.21) | 1.42 | - |
| Cash dividends declared per common share | - | - | - | - | - | - |
| **Balance Sheet Data (At the end of the Period)** | | | | | | |
| Total assets | 1,219,405 | 1,119,269 | - | 656,528 | 990,893 | 940,619 |
| Long-term debt | 240,000 | 240,000 | - | - | 507 | 684 |
| Stockholders' equity/owner's net investment | 822,289 | 715,423 | - | 223,451 | 233,847 | 162,407 |

(1) Includes a $202.1 million impairment charge for the year ended December 31, 2004.

**Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations**

***Overview***

We are an independent oil and natural gas company engaged in the acquisition, exploration, development and production of natural gas and oil properties in the United States. We were formed as a Delaware corporation in June 2005. In July 2005, we acquired the oil and natural gas business of Calpine Corporation and affiliates. We own producing and non-producing oil and natural gas properties in the Sacramento Basin of California, the Lobo and Perdido Trends in South Texas, the State Waters of Texas, the Gulf of Mexico, the Rocky Mountains and other properties located in various geographical areas in the United States. In this section, we refer to Rosetta as “Successor” and to the domestic oil and natural gas properties acquired from Calpine as “Predecessor”.

In accounting for the oil and natural gas exploration and production business, the Predecessor used the successful efforts method of accounting for oil and natural gas activities. However, in connection with our separation from

Calpine, we have adopted the full cost method of accounting for our oil and natural gas properties, (see “Critical Accounting Policies and Estimates—Oil and Gas Activities” below for further discussion of the differences on the Consolidated/Combined Financial Statements of the two accounting methods).

We plan our activities and budget based on conservative sales price assumptions given the inherent volatility of oil and natural gas prices that are influenced by many factors beyond our control. We focus our efforts on increasing oil and natural gas reserves and production while controlling costs at a level that is appropriate for long-term operations. Our future earnings and cash flows are dependent on our ability to manage our overall cost structure to a level that allows for profitable production. Our future earnings will also be impacted by the changes in the fair market value of hedges we executed to mitigate the volatility in the changes of oil and natural gas prices in future periods. These instruments meet the criteria to be accounted for as cash flow hedges, and until settlement, the changes in fair market value of our hedges will be included as a component of stockholder’s equity to the extent effective. In periods of rising prices, these transactions will mitigate future earnings and in periods of declining prices will increase future earnings in the respective period the positions are settled.

Like all oil and natural gas exploration and production companies, we face the challenge of natural production declines. As initial reservoir pressures are depleted, oil and natural gas production from a given well naturally decreases. Thus, an oil and natural gas exploration and production company depletes part of its asset base with each unit of oil or natural gas it produces. We attempt to overcome this natural decline by drilling and acquiring more reserves than we produce. Our future growth will depend on our ability to continue to add reserves in excess of production. We will maintain our focus to add reserves through drilling and acquisitions as well as the costs necessary to produce our reserves. Our ability to add reserves through drilling is dependent on our capital resources and can be limited by many factors, including our ability to timely obtain drilling permits and regulatory approvals. The permitting and approval process has been more difficult in recent years than in the past due to increased activism from environmental and other groups and has extended the time it takes us to receive permits. Because of our relatively small size and concentrated property base, we can be disproportionately disadvantaged by delays in obtaining or failing to obtain drilling approvals compared to companies with larger or more diverse property bases. As a result, we are less able to shift drilling activities to areas where permitting may be easier and we have fewer properties over which to spread the costs related to complying with these regulations and the costs or foregone opportunities resulting from delays.

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At the closing of the Acquisition on July 7, 2005, we retained approximately $75 million of the purchase price in respect to Non-Consent Properties. As such, our operating income does not include volumes and revenues related to these oil and natural gas properties not conveyed by Calpine. The total SEC PV-10 value of these wells and the associated leases was $53.0 million pretax at December 31, 2006.

***Financial Highlights***

The Consolidated Financial Statements reflect total revenue of $271.8 million on total volumes of 33.4 Bcfe for the year ended December 31, 2006 (Successor). Operating income was $85.1 million or 31% of total revenue and included workover costs of approximately $6.5 million and $5.7 million of compensation expense for stock-based compensation granted to employees. Total net other income was comprised of interest expense (net of capitalized interest) on our credit facility offset by interest income on short term cash investments. Overall, our net income for the year ended December 31, 2006 (Successor) was $44.6 million or 16% of total revenue.

***Critical Accounting Policies and Estimates***

The discussion and analysis of our financial condition and results of operations are based upon the Consolidated/Combined Financial Statements, which have been prepared in accordance with accounting principles generally accepted in the United States of America. The preparation of these financial statements requires us to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, related disclosure of contingent assets and liabilities and proved oil and gas reserves. Certain accounting policies involve judgments and uncertainties to such an extent that there is reasonable likelihood that materially different amounts could have been reported under different conditions, or if different assumptions had been used. We evaluate our estimates and assumptions on a regular basis. We base our estimates on historical experience and various other assumptions that are believed to be reasonable under the circumstances, the results of which form the basis for making judgments about the carrying values of assets and liabilities that are not readily apparent from other sources. Actual results may differ from these estimates and assumptions used in preparation of our financial statements. Below, we have provided expanded discussion of our more significant accounting policies, estimates and judgments for our financial statements and those of our Predecessor. We believe these accounting policies reflect the more significant estimates and assumptions used in preparation of the financial statements.

We also describe the most significant estimates and assumptions we make in applying these policies. See Item 8. Consolidated Financial Statements and Supplementary Data Note 3, *Summary of Significant Accounting Policies*, for a discussion of additional accounting policies and estimates made by management.

*Oil and Gas Activities*

Accounting for oil and gas activities is subject to special, unique rules. Two generally accepted methods of accounting for oil and gas activities are available which include the successful efforts method or the full cost method. The most significant differences between these two methods are the treatment of exploration costs and the manner in which the carrying value of oil and gas properties are amortized and evaluated for impairment. The successful efforts method, as used by our Predecessor, requires exploration costs to be expensed as they are incurred while the full cost method provides for the capitalization of these costs. Both methods generally provide for the periodic amortization of capitalized costs based on proved reserve quantities. Impairment of oil and gas properties under the successful efforts method is based on an evaluation of the carrying value of individual oil and gas properties against their estimated fair value. For the year ended December 31, 2004, our Predecessor recorded a $202.1 million impairment related to a reduction of proved reserve projections based on the year-end independent engineers report. The assessment for impairment under the full cost method requires an evaluation of the carrying value of oil and gas properties included in a cost center against the net present value of future cash flows from the related proved reserves, using period-end prices and costs and a 10% discount rate.

*Full Cost Method*

We use the full cost method of accounting for our oil and gas activities. Under this method, all costs incurred in the acquisition, exploration and development of oil and gas properties are capitalized into a cost center (the amortization base), whether or not the activities to which they apply are successful. Such amounts include the cost of drilling and equipping productive wells, dry hole costs, lease acquisition costs and delay rentals. Capitalized costs also include salaries, employee benefits, costs of consulting services and other expenses that are estimated to directly relate to our oil and gas activities. Interest costs related to unproved properties are also capitalized. Although some of these costs will ultimately result in no additional reserves, we expect the benefits of successful wells to more than offset the costs of any unsuccessful ones. Costs associated with production and general corporate activities are expensed in the period incurred. The capitalized costs of our oil and gas properties, plus an estimate of our future development and abandonment costs, are amortized on a unit-of-production method based on our estimate of total proved reserves. Unevaluated costs are excluded from the full cost pool and are periodically considered for impairment rather than amortization. Upon evaluation, these costs are transferred to the full cost pool and amortized. Our financial position and results of operations would have been significantly different had we used the successful efforts method of accounting for our oil and gas activities, as used by our Predecessor, and as presented herein for the six months ended June 30, 2005 and the year ended December 31, 2004, since we generally reflect a higher level of capitalized costs as well as a higher depreciation, depletion and amortization rate on our oil and natural gas properties.

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*Proved Oil and Gas Reserves*

Our engineering estimates of proved oil and gas reserves directly impact financial accounting estimates, including depreciation, depletion and amortization expense and the full cost ceiling limitation. Proved oil and gas reserves are the estimated quantities of oil and gas reserves that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under period-end economic and operating conditions. The process of estimating quantities of proved reserves is very complex, requiring significant subjective decisions in the evaluation of all geological, engineering and economic data for each reservoir. Accordingly, our reserve estimates are developed internally and subsequently, provided to a third party engineering firm who then generates an annual year-end reserve report. The data for a given reservoir may change substantially over time as a result of numerous factors including additional development activity, evolving production history and continual reassessment of the viability of production under varying economic conditions. Changes in oil and gas prices, operating costs and expected performance from a given reservoir also will result in revisions to the amount of our estimated proved reserves. The estimate of proved oil and natural gas reserves primarily impact property, plant and equipment amounts in the balance sheets and the depreciation, depletion and amortization amounts in the consolidated/combined statement of operations, among other items. For more information regarding reserve estimation, including historical reserve revisions, refer to Item 8. Consolidated Financial Statements and Supplementary Data, Supplemental Oil and Gas Disclosure.

*Depreciation, Depletion and Amortization*

The quantities of estimated proved oil and gas reserves are a significant component of our calculation of depletion expense and revisions in such estimates may alter the rate of future expense. Holding all other factors constant, if reserves are revised upward, earnings would increase due to lower depletion expense. Likewise, if reserves are revised downward, earnings would decrease due to higher depletion expense or due to a ceiling test write-down. A five percent positive or negative revision to proved reserves throughout the Company would decrease or increase the depreciation, depletion and amortization rate by approximately $0.12 to $0.13 per MMcfe. This estimated impact is based on current data at December 31, 2006 and actual events could require different adjustments to depreciation, depletion and amortization.

*Full Cost Ceiling Limitation*

Our ceiling test computation was calculated using hedge adjusted market prices at December 31, 2006 which were based on a Henry Hub price of $5.64 per MMBtu and a West Texas Intermediate oil price of $60.50 per Bbl (adjusted for basis and quality differentials). The use of these prices would have resulted in an after-tax writedown of $85 million at December 31, 2006. Cash flow hedges of natural gas production in place at December 31, 2006 increased the calculated ceiling value by approximately $47 million (net of tax). However, subsequent to December 31, 2006 the market price for Henry Hub increased to $7.52 per MMBtu and the price for West Texas Intermediate increased to $61.84 per Bbl, and utilizing these prices our net capitalized costs of oil and gas properties exceeded the ceiling amount. As a result no writedown was recorded at December 31, 2006. The ceiling value calculated using subsequent prices includes approximately $6 million related to the positive effects of future cash flow hedges of natural gas production. Due to the volatility of commodity prices, should natural gas prices decline in the future, it is possible that a writedown could occur.

There was no ceiling test writedown for the six months ended December 31, 2005.

*Future Development and Abandonment Costs*

Future development costs include costs incurred to obtain access to proved reserves such as drilling costs and the installation of production equipment. Future abandonment costs include costs to dismantle and relocate or dispose of our production platforms, gathering systems and related structures and restoration costs of land and seabed. We develop estimates of these costs for each of our properties based upon their geographic location, type of production structure, well depth, currently available procedures and ongoing consultations with construction and engineering consultants. Because these costs typically extend many years into the future, estimating these future costs is difficult and requires management to make judgments that are subject to future revisions based upon numerous factors, including changing technology and the political and regulatory environment. We review our assumptions and estimates of future development and future abandonment costs on an annual basis.

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We provide for future abandonment costs in accordance with SFAS No. 143,"Accounting for Asset Retirement Obligations". This standard requires that a liability for the discounted fair value of an asset retirement obligation be recorded in the period in which it is incurred and the corresponding cost capitalized by increasing the carrying amount of the related long-lived asset. The liability is accreted to its present value each period, and the capitalized cost is depreciated over the useful life of the related asset. Holding all other factors constant, if our estimate of future abandonment and development costs is revised upward, earnings would decrease due to higher depreciation, depletion and amortization (DD&A) expense. Likewise, if these estimates are revised downward, earnings would increase due to lower DD&A expense.

*Income Taxes*

We provide for deferred income taxes on the difference between the tax basis of an asset or liability and its carrying amount in our financial statements in accordance with SFAS No. 109, "Accounting for Income Taxes". This difference will result in taxable income or deductions in future years when the reported amount of the asset or liability is recovered or settled, respectively. Considerable judgment is required in determining when these events may occur and whether recovery of an asset is more likely than not. Deferred tax assets are reduced by a valuation allowance when, in the opinion of management, it is more likely than not that some portion or all of the deferred tax assets will not be realized.

Estimating the amount of the valuation allowance is dependent on estimates of future taxable income, alternative minimum tax income and change in stockholder ownership that would trigger limits on use of net operating losses under the Internal Revenue Code Section 382. We have a significant deferred tax asset associated with net operating loss carryforwards (NOLs). It is more likely than not that we will use these NOLs to offset current tax liabilities in future years. Our NOLs are more fully described in "Item 8. Financial Statements and Supplementary Data - Note 13.

Additionally, our federal and state income tax returns are generally not filed before the Consolidated Financial Statements are prepared, therefore we estimate the tax basis of our assets and liabilities at the end of each period as well as the effects of tax rate changes, tax credits and net operating and capital loss carryforwards and carrybacks. Adjustments related to differences between the estimates we used and actual amounts we reported are recorded in the period in which we file our income tax returns. These adjustments and changes in our estimates of asset recovery could have an impact on our results of operations. A one percent change in our effective tax rate would have affected our calculated income tax expense by approximately $0.7 million for the year ended December 31, 2006.

*Derivative Transactions and Hedging Activities*

We enter into derivative transactions to hedge against changes in oil and natural gas prices from time to time primarily through the use of fixed price swap agreements, costless collars, and put options. Consistent with our hedge policy, we entered into a series of natural gas fixed-price swaps and costless collars for a significant portion of our expected natural gas production through 2009. These transactions are recorded in our financial statements in accordance with SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities" ("SFAS No. 133"). Although not risk free, we believe this policy will reduce our exposure to commodity price fluctuations and thereby achieve a more predictable cash flow. We do not enter into derivative agreements for trading or other speculative purposes.

In accordance with SFAS No. 133, as amended, all derivative instruments, unless designated as normal purchase normal sale, are recorded on the balance sheet at fair market value and changes in the fair market value of the derivatives are recorded each period in current earnings or other comprehensive income, depending on whether a derivative is designated as a hedge transaction, and depending on the type of hedge transaction. Our derivative contracts are cash flow hedge transactions in which we are hedging the variability of cash flow related to a forecasted transaction. Changes in the fair market value of these derivative instruments are reported in other comprehensive income and reclassified as earnings in the period(s) in which earnings are impacted by the variability of the cash flow of the hedged item. We assess the effectiveness of hedging transactions quarterly, consistent with our documented risk management strategy for the particular hedging relationship. Changes in the fair market value of the ineffective portion of cash flow hedges are included in other income (expense).

*Stock -Based Compensation*

On January 1, 2003, Calpine prospectively adopted the fair market value method of accounting for stock-based employee compensation pursuant to SFAS No. 123. Expense amounts included in the combined historical financial statements for the year ended December 31, 2004 and the six months ended June 30, 2005 are based on stock based compensation granted to employees by Calpine. Stock options were granted at an option price equal to the quoted market price at the date of the grant or award.

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In determining our accounting policies, we chose to apply the intrinsic value method pursuant to APB No. 25 effective July 2005, and as required have adopted the guidance for stock-based compensation under SFAS No. 123R effective January 1, 2006.

SFAS No. 123R applies to all awards granted, modified, repurchased or cancelled after January 1, 2006 and to the unvested portion of all awards granted prior to that date. We adopted this statement using the modified version of the prospective application (modified prospective application). Under the modified prospective application, compensation cost for the portion of awards for which the employee's requisite service has not been rendered that are outstanding as of January 1, 2006 must be recognized as the requisite service is rendered on or after that date. The compensation cost for that portion of awards shall be based on the original fair market value of those awards on the date of grant as calculated for recognition under SFAS No. 123. The compensation cost for these earlier awards shall be attributed to periods beginning on or after January 1, 2006 using the attribution method that was used under SFAS No. 123.

***Recent Accounting Developments***

*The Fair Value Option for Financial Assets and Financial Liabilities.* In February 2007, the FASB issued SFAS No. 159, "The Fair Value Option For Financial Assets and Financial Liabilities - Including an Amendment of FASB Statement No. 115" ("SFAS No. 159), which permits an entity to choose to measure certain financial assets and liabilities at fair value. SFAS No. 159 also revises provisions of SFAS No. 115 that apply to available-for-sale and trading securities. This statement is effective for fiscal years beginning after November 15, 2007. The Company has not yet evaluated the potential impact of this standard.

*Fair Value Measurements*. In September 2006, the FASB issued SFAS No. 157*,*"Fair Value Measurements" ("SFAS No. 157"), which addresses how companies should measure fair value when companies are required to use a fair value measure for recognition or disclosure purposes under generally accepted accounting principles ("GAAP"). As a result of SFAS No. 157, there is now a common definition of fair value to be used throughout GAAP. SFAS No. 157 is effective for financial statements issued for fiscal years beginning after November 15, 2007, and interim periods within those years. Although the disclosure requirements may be expanded where certain assets or liabilities are fair valued, the Company does not expect the adoption of SFAS No. 157 to have a material impact on the Company's consolidated financial position, results of operations, or cash flows. We are still assessing the impact of this standard but we do not expect the adoption of this standard to have a material impact on our consolidated financial position, results of operations, or cash flows.

*Guidance for Quantifying Financial Statement Misstatement.* In September 2006, the SEC issued Staff Accounting Bulletin No. 108, "Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements" ("SAB 108"), which establishes an approach requiring the quantification of financial statement errors based on the effect of the error on each of the company's financial statements and the related financial statement disclosures. This model is commonly referred to as a "dual approach" because it requires quantification of errors under both the "iron curtain" and "roll-over" methods. The roll-over method focuses primarily on the impact of a misstatement on the income statement, including the reversing effect of prior year misstatements; however, its use can lead to the accumulation of misstatements in the balance sheet. The iron curtain method focuses primarily on the effect of correcting the period end balance sheet with less emphasis on the reversing effects of prior year errors on the income statement. The Company used the iron curtain method for quantifying financial statement misstatements. The Company has applied the provisions of SAB 108 in connection with the preparation of the Company's annual financial statements for the year ending December 31, 2006. The use of the dual approach did not have a material impact on the Company's consolidated financial position, results of operations, or cash flows.

*Accounting for Uncertainty in Income Taxes.* In June 2006, the FASB issued FASB Interpretation No. 48, "Accounting for Uncertainty in Income Taxes - an interpretation of FASB Statement No. 109"("FIN 48"). This interpretation provides guidance for recognizing and measuring uncertain tax positions, as defined in SFAS No. 109, “Accounting for Income Taxes.” FIN 48 prescribes a threshold condition that a tax position must meet for any of the benefit of the uncertain tax position to be recognized in the financial statements. Guidance is also provided regarding derecognition, classification and disclosure of these uncertain tax positions. FIN 48 is effective for fiscal years beginning after December 15, 2006. We are evaluating our tax positions and anticipate that the interpretation will not have a significant impact on the Company’s retained earnings at the time of adoption.

*Accounting for Certain Hybrid Financial Instruments*. In February 2006, the FASB issued SFAS No. 155, “Accounting for Certain Hybrid Instruments - an amendment of FASB Statements 133 and 140”, which is effective for all financial instruments acquired or issued after the beginning of an entity’s first fiscal year that begins after September 15, 2006. The statement improves financial reporting by eliminating the exemption from applying SFAS No. 133 to interests in securitized financial assets so that similar instruments are accounted for similarly regardless of the form of the instruments. The statement also improves financial reporting by allowing a preparer to elect fair value measurement at acquisition, at issuance, or when a previously recognized financial instrument is subject to a re-measurement event, on an instrument-by-instrument basis, in cases in which a derivative would otherwise have to be bifurcated, if the holder elects to account for the whole instrument on a fair value basis. The adoption of this statement is not expected to have a material impact on the Company’s consolidated financial position, results of operations, or cash flows.

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**Results of Operations**

Due to the acquisition of Calpine Natural Gas L.P. in July 2005, the year ended December 31, 2006 financial data is not comparative with 2005 or 2004. As such, the results of operations for the year ended December 31, 2005 are presented in two periods, Successor comprising the six months ended December 31, 2005 and Predecessor comprising the six months ended June 30, 2005. The results of operations for the year ended December 31, 2004 are also shown as Predecessor. See Note 2 to the Consolidated/Combined Financial Statements for the summary pro forma effect of the Acquisition for the years ended December 31, 2005 and 2004.

Differences in accounting principles also exist between us and Calpine, primarily the full cost method of accounting for oil and natural gas properties adopted by us and the successful efforts method of accounting for oil and natural gas properties followed by Calpine. In addition, Calpine adopted on January 1, 2003, SFAS No. 123 to measure the cost of employee services received in exchange for an award of equity instruments at fair value, whereas we adopted the intrinsic value method of accounting for stock options and stock awards effective July 1, 2005, and as required, have adopted the guidance for stock-based compensation under SFAS No. 123R effective January 1, 2006. See Note 3 to the Consolidated/Combined Financial Statements for further discussion regarding the adoption of SFAS 123R.

We believe comparative results would be misleading and, therefore, have presented the information below separately as Successor and Predecessor.

| | Successor-Consolidated | | Predecessor-Combined | |
|---|---|---|---|---|
| | Year Ended December 31, 2006 | Six Months Ended December 31, 2005 | Six Months Ended June 30, 2005 | Year Ended December 31, 2004 |
| | (In thousands, except per unit amounts) | | | |
| Total revenues | $ 271,763 | $ 113,104 | $ 103,831 | $ 248,006 |
| | | | | |
| **Production:** | | | | |
| Gas (Bcf) | 30.3 | 12.4 | 14.5 | 37.3 |
| Oil (MBbls) | 551.3 | 185.6 | 163.8 | 600.0 |
| Total Equivalents (Bcfe) | 33.4 | 13.5 | 15.5 | 40.9 |
| | | | | |
| **$ per unit:** | | | | |
| Avg. Gas Price per Mcf | $ 7.81 | $ 8.23 | $ 6.59 | $ 6.02 |
| Avg. Gas Price per Mcf excluding Hedging | 6.83 | 9.57 | - | - |
| Avg. Oil Price per Bbl | 64.01 | 59.52 | 49.86 | 39.08 |
| Avg. Revenue per Mcfe | $ 8.14 | $ 8.38 | $ 6.70 | $ 6.06 |

**Revenues**

**Year Ended December 31, 2006 (Successor)**

Our revenues are derived from the sale of our oil and natural gas production, which includes the effects of qualifying hedge contracts. Total revenue of $271.8 million for the year ended December 31, 2006 consists primarily of natural gas sales comprising 87% of total revenue on total volumes of 33.4 Bcfe.

***Natural Gas***. Natural gas sales revenue was $236.5 million, including the effects of hedging, based on total gas production volumes of 30.3 Bcf. Approximately 75% of the production volumes were from the following three areas: California, Lobo, and Perdido. Average natural gas prices were $7.81 for the respective period. The effect of hedging on natural gas sales revenue was an increase of $29.6 million for an increase in total price from $6.83 to $7.81 per Mcf.

***Crude Oil***. Oil sales revenue was $35.3 million for the year ended December 31, 2006 with oil production volumes of 551.3 MBbls. The oil production volumes were primarily in the Offshore and Other Onshore regions with approximately 75% of the total production volumes. The average oil price was $64.01 per Bbl for the year ended December 31, 2006.

**Six Months Ended December 31, 2005 (Successor)**

Total revenue of $113.1 million for the six months ended December 31, 2005 consists primarily of natural gas sales comprising 90% of total revenue on total volumes of 13.5 Bcfe.

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***Natural Gas.*** Natural gas sales revenue was $102.1 million, including the effects of hedging, based on total gas production volumes of 12.4 Bcf. Lobo and Perdido production was 3.9 Bcf and 1.5 Bcf or 28.9% and 11.2%, respectively, or a total of 5.4 Bcf and 40.1% of total volumes. California production was 5.3 Bcf or 39.0% of total volumes at a average price of $9.08 per Mcfe, excluding the effects of hedging. California production was affected by the delay in our drilling program and compression issues. The effect of hedging on natural gas sales revenue was a decrease of $16.6 million related to volumes of 8.0 MMBtu for a decrease in total price to $8.23 per Mcf.

***Crude Oil.*** Oil revenue was $11.0 million based on oil production volumes of 185.6 MBbls. The Southern region production was 21.9 MBbls, 8.5 MBbls, 8.3 MBbls, 42.0 MBbls and 93.0 MBbls from Lobo, Perdido, State Waters, Other Onshore and Gulf of Mexico or 94% of oil production for the six months ended December 31, 2005 at a total average price of $59.61 per Bbl for these fields. Overall volumes in the Gulf of Mexico were affected by Hurricanes Katrina and Rita. In addition, production volumes were also affected by a workover program at High Island and East Cameron which was delayed in prior years due to capital constraints imposed by Calpine. Fluctuations in product prices significantly impacted our revenue from existing properties.

**Six Months Ended June 30, 2005 (Predecessor)**

Total revenue of $103.8 million for the six months ended June 30, 2005 consists primarily of natural gas sales comprising 92% of total revenue on total volumes of 15.5 Bcfe.

***Natural Gas***. Natural gas sales revenue was $95.6 million with natural gas production volumes of 14.5 Bcf for the six months ended June 30, 2005. The production volumes were primarily from the Sacramento Basin with 6.5 Bcf or 44.8% and Lobo and Perdido with a combined production of 5.5 Bcf or 37.9%. Production volumes were lower than expected due to capital expenditure constraints resulting in reduced drilling activity. The average price for natural gas was $6.59 per Mcf. There was no hedging activity for the six months ended June 30, 2005.

***Crude Oil***. For the six months ended June 30, 2005, crude oil sales revenue was $8.2 million based on production volumes of 163.8 MBbls. Production volumes were primarily from the Gulf of Mexico region which produced 72.7 MBbls or 44% of the total oil production. The average price of oil was $49.86 per Bbl for the six months ended June 30, 2005.

**Year Ended December 31, 2004 (Predecessor)**

Total revenue of $248.0 million for the year ended December 31, 2004 consists primarily of natural gas sales comprising 91% of total revenue on total volumes of 40.9 Bcfe.

**Natural Gas.** Natural gas sales revenue was $224.6 million with natural gas production volumes of 37.3 Bcf for the year ended December 31, 2004. The production volumes were lower than expected due to the capital constraints of our Predecessor which impacted the exploration and development program. The average price for natural gas was $6.02 per Mcf.

**Crude Oil.** For the year ended December 31, 2004, oil sales revenue was $23.4 million based on production volumes of 600.0 MBbls. The production volumes were primarily from the offshore area in the Gulf of Mexico. The average oil price was $39.08 per Bbl for the year ended December 31, 2004.

**Operating Expenses**

The following table presents information about our operating expenses:

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| | Successor-Consolidated | | Predecessor-Combined | |
|---|---|---|---|---|
| | Year Ended December 31, 2006 | Six Months Ended December 31, 2005 | Six Months Ended June 30, 2005 | Year Ended December 31, 2004 |
| | (In thousands, except per unit amounts) | | | |
| Lease operating expense | $ 36,273 | $ 15,674 | $ 16,629 | $ 30,785 |
| Depreciation, depletion and amortization | 105,886 | 40,500 | 30,679 | 81,590 |
| Impairment | - | - | - | 202,120 |
| General and administrative costs | $ 33,233 | $ 14,687 | $ 9,677 | $ 19,416 |
| | | | | |
| **$ per unit:** | | | | |
| Avg. lease operating expense per Mcfe | $ 1.09 | $ 1.16 | $ 1.08 | $ 0.75 |
| Avg. DD&A per Mcfe (Excluding impairments) | 3.17 | 3.00 | 1.98 | 2.00 |
| Avg. G&A per Mcfe | $ 1.00 | $ 1.09 | $ 0.63 | $ 0.48 |

**Year Ended December 31, 2006 (Successor)**

*Lease Operating Expense*. Lease operating expense of $36.3 million related directly to oil and gas volumes which totaled 33.4 Bcfe for the year ended December 31, 2006 or costs of $1.09 per Mcfe. Lease operating costs were affected by the wells that came on-line in South Texas. Lease operating expense includes workover costs of $0.19 per Mcfe, ad valorem taxes of $0.20 per Mcfe and insurance of $0.04 per Mcfe.

*Depreciation, Depletion and Amortization.* Depreciation, depletion and amortization was $105.9 million for the year ended December 31, 2006 under the full cost method of accounting. The depletion rate was $3.10 per Mcfe.

*General and Administrative costs.* For the year ended December 31, 2006, general and administrative costs were $33.2 million, net of capitalization of certain general and administrative costs of $3.4 million under the full cost method of accounting for oil and natural gas properties. General and administrative costs include salary and employee benefits as well as legal, consulting and auditing fees. In addition, stock compensation expense for the year ended December 31, 2006 was $5.7 million and is included in general and administrative costs.

**Six Months Ended December 31, 2005 (Successor)**

*Lease Operating Expense.* Our lease operating expense of $15.7 million is primarily due to oil and natural gas volumes which totaled 13.5 Bcfe for the six months ended December 31, 2005 or costs of $1.16 per Mcfe. The costs include workover costs on our High Island A-442 and East Cameron 88 wells in the Gulf of Mexico and the La Perla field in South Texas. Lease operating costs included workover costs, ad valorem taxes and insurance of $0.22 per Mcfe, $0.25 per Mcfe and $0.04 per Mcfe, respectively.

*Depreciation, Depletion and Amortization.* Depreciation, depletion and amortization expense was $40.5 million for the six months ended December 31, 2005. We adopted the full cost method of accounting for oil and gas properties as further discussed in our “Critical Accounting Policies and Estimates” above whereby related costs are capitalized into the full cost pool. Our depletion rate for this period was an average of $3.00 per Mcfe. There were no ceiling test write-downs for the six months ended December 31, 2005.

*General and Administrative Costs.* General and administrative costs of $14.7 million is net of capitalization of general and administrative costs of $3.5 million as a component of our oil and natural gas properties under the full cost method of accounting for oil and natural gas properties which we adopted July 1, 2005. General and administrative costs for this period include $4.2 million of stock compensation expense for stock granted to employees during the period and $10.9 million of salary and employee benefit costs before capitalization of any of these costs to our oil and natural gas properties.

**Six Months Ended June 30, 2005 (Predecessor)**

*Lease Operating Expense.* Lease Operating Expense was $16.6 million and related to total oil and gas volumes of 15.5 Bcfe or $1.08 per Mcfe for the six months ended June 30, 2005. Lease operating costs include work over cost of $0.22 per Mcfe, ad valorem taxes of $0.22 per Mcfe and insurance of $0.06 per Mcfe. These costs are due to higher taxes in South Texas and a special reclamation tax in California.

*Depreciation, Depletion and Amortization.* For the six months ended June 30, 2005, depreciation, depletion, and amortization expense was $30.7 million. The predecessor used the successful efforts method of accounting for oil and natural gas properties. The depletion rate was $1.97 per Mcfe for the six months ended June 30, 2005.

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*General and Administrative Costs.* General and administrative costs for the six months ended June 30, 2005 were $9.7 million, which is net of capitalized general and administrative costs of $3.6 million. General and administrative costs are comprised of items such as salaries and employee benefits, legal fees, and contract fees. For the six months ended June 30, 2005, of the $9.7 million in total general and administrative costs, $5.9 million relates to salary and employee benefits. In addition, $1.3 million are legal costs and $1.7 million are merger and acquisition costs, which relate to the sale of the oil and natural gas business to the Company.

**Year Ended December 31, 2004 (Predecessor)**

*Lease Operating Expense.* For the year ended December 31, 2004, lease operating expense was $30.8 million or $0.75 per Mcfe. These expenses primarily related to non-operated lease expense associated with drilling activity in the Impac field in South Texas operated by EOG Resources, Inc. Lease operating expenses also include items such as costs related to salt water disposal (primarily in California), supervisory and labor costs, ad valorem taxes and well servicing costs.

*Depreciation, Depletion and Amortization*. The depreciation, depletion and amortization expense of $81.6 million primarily related to the addition of 20 new wells in the Impac field in South Texas during 2004. Under successful efforts accounting, depletion expense is separately computed for each field. The capital expenditures for proved properties for each field compared to the proved reserves corresponding to each field to determine a depletion rate for current production. The DD&A rate in South Texas was approximately $3.50 per Mcfe in 2004 as the costs associated with drilling these wells increased significantly relative to the reserves added during the period.

*Impairment*. During 2004, our Predecessor revised downward its estimate of proved reserves by a total of approximately 58 Bcfe, or 12% as of December 31, 2004. Approximately 69% of the total revision was attributable to the downward revision of the estimate of proved reserves in the South Texas fields and to a smaller extent unanticipated well performance decline in offshore fields. The remaining 31% of the total revision was primarily due to the downward revision of our Predecessor's estimate of proved reserves in California of 17%, Other Onshore of 10% and Gulf of Mexico of 4%. The downward revisions of our predecessor's estimates were based on the independent reservoir engineer's year-end reserve report, which reflected production results and drilling activity that occurred during 2004 and used historical field level decline curves. Due to significant capital constraints by our Predecessor, drilling activity was minimized and correspondingly the estimate of proved reserves could not be supported through drilling success or future capital activity and the downward revision was required. In addition, under the successful efforts method of accounting for oil and natural gas properties, individual assets are grouped at the lowest level for which there are identifiable cash flows. With minimal drilling activity and the evaluation of cash flows at this level, proved reserves for South Texas and California fields and the Gulf of Mexico had to be revised downward at each individual field level. As a result of the decreases, primarily in proved undeveloped reserves, a non-cash impairment charge of approximately $202.1 million was recorded for the year ended December 31, 2004.

*General and Administrative.* General and administrative costs were $19.4 million in 2004. General and administrative costs are comprised of items such as salaries and employee benefits, legal fees, contract fees and the corporate overhead allocation. In addition, General and administrative costs include stock-based compensation. On January 1, 2003, the Predecessor adopted the fair market value method of accounting for stock-based compensation pursuant to SFAS No. 123. Stock compensation expense of $0.8 million was recorded in 2004.

**Total Other expense**

Other expense for the year ended December 31, 2006 (Successor) was $12.9 million and is primarily comprised of interest expense of $17.4 million (net of $2.1 million of capitalized interest) offset by interest income of $4.5 million. The interest expense is associated with the senior secured revolving line of credit and second lien term loan and the interest income is related to the interest earned on the overnight investments of our cash balances.

Other expense for the six months ended December 31, 2005 (Successor) is primarily associated with interest expense of $8.2 million, including amortization of deferred loan fees of $0.6 million related to interest on our senior credit facility and term loan. Interest income of $1.8 million was earned on available cash invested in short term money market investments.

For the six months ended June 30, 2005, other expense of $7.0 million was associated with the intercompany debt with Calpine Corporation.

For the year ended December 31, 2004, other expense was primarily associated with interest expense on intercompany debt with Calpine Corporation. The intercompany debt balances at December 31, 2004 were $127.2 million. Interest rates on affiliated party debt ranged from 8.75% to 9.05% in 2004. Capitalized interest was $0.7 million in 2004.

**Provision for Income Taxes**

For the year ended December 31, 2006 and six months ended December 31, 2005 (Successor), the effective tax rate was 38.3% and 39.7%, respectively. For the six months ended June 30, 2005 and year ended December 31, 2004 (Predecessor), the effective tax rate was 38.1% for both periods. The provision for income taxes differs from the taxes computed at the federal statutory income tax rate due primarily to state taxes.

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**Liquidity and Capital Resources**

Our primary source of capital and liquidity is our operating cash flow. We also maintain a revolving line of credit which can be assessed as needed to supplement operating cash flow. In addition, concurrent with the Acquisition, BNP Paribas provided us with a second lien term loan.

*Operating cash flow.* Our cash flows depend on many factors, including the price of oil and natural gas and the success of our development and exploration activities as well as future acquisitions. We actively manage our exposure to commodity price fluctuations by executing derivative transactions to hedge the change in prices of our production thereby mitigating our exposure to price declines, but these transactions will also limit our earnings potential in periods of rising natural gas prices. This derivative transaction activity will allow us the flexibility to continue to execute our capital plan if prices decline during the period our derivative transactions are in place. In addition, the majority of our capital expenditures will be discretionary and could be curtailed if our cash flows decline from expected levels.

*Senior Secured Revolving Line of Credit.* BNP Paribas, in July 2005 provided us with a senior secured revolving line of credit concurrent with the Acquisition in the amount of up to $400.0 million ("Revolver"). This Revolver was syndicated to a group of lenders on September 27, 2005. Availability under the Revolver is restricted to the borrowing base, which initially was $275.0 million and was reset to $325.0 million, upon amendment, as a result of the hedges put in place in July 2005 and the favorable effects of the exercise of the over-allotment option we granted in our private equity offering in July 2005 through which we received $70.0 million of funds (net of transaction fees). In July 2005, we repaid $60.0 million of the $225.0 million in original borrowings on the Revolver. The borrowing base is subject to review and adjustment on a semi-annual basis and other interim adjustments, including adjustments based on our hedging arrangements. Amounts outstanding under the Revolver bear interest, as amended, at specified margins over the London Interbank Offered Rate ("LIBOR") of 1.25% to 2.00% (6.85% at December 31, 2006). Such margins will fluctuate based on the utilization of the facility. Borrowings under the Revolver are collateralized by perfected first priority liens and security interests on substantially all of our assets, including a mortgage lien on oil and natural gas properties having at least 80% of the SEC PV-10 pretax reserve value, a guaranty by all of our domestic subsidiaries, a pledge of 100% of the stock of domestic subsidiaries and a lien on cash securing the Calpine gas purchase and sale contract. These collateralized amounts under the mortgages are subject to semi-annual reviews based on updated reserve information. We are subject to the financial covenants of a minimum current ratio of not less than 1.0 to 1.0 as of the end of each fiscal quarter and a maximum leverage ratio of not greater than 3.5 to 1.0, calculated at the end of each fiscal quarter for the four fiscal quarters then ended, measured quarterly with the pro forma effect of acquisitions and divestitures. At December 31, 2006, our current ratio was 2.7 to 1.0, as adjusted per current agreements and our leverage ratio was 1.2 to 1.0. 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 were in compliance with all covenants at December 31, 2006. All amounts drawn under the Revolver are due and payable on July 7, 2009. Availability under the revolving line of credit was $159.0 million at December 31, 2006.

*Second Lien Term Loan.* In July 2005, BNP Paribas provided us with a second lien term loan in the amount of $100.0 million ("Term Loan"). On September 27, 2005, we repaid $25.0 million of borrowings on the Term Loan, reducing the balance to $75.0 million and syndicated the Term Loan to a group of lenders including BNP Paribas. Borrowings under the Term Loan initially bore interest at LIBOR plus 5.00%. As a result of the hedges put in place in July 2005 and the favorable effects of our private equity placement, as described above, the interest rate for the Term Loan has been reduced to LIBOR plus 4.00% (9.35% at December 31, 2006). The Term Loan is collateralized by second priority liens on substantially all of our assets. We are subject to the financial covenants of a minimum asset coverage ratio of not less than 1.5 to 1.0 and a maximum leverage ratio of not more than 4.0 to 1.0, calculated at the end of each fiscal quarter for the four fiscal quarters then ended, measured quarterly with the pro forma effect of acquisitions and divestitures. 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 were in compliance with all covenants at December 31, 2006. The revised principal balance of the Term Loan is due and payable on July 7, 2010.

**Working Capital**

At December 31, 2006, we had a working capital surplus of $30.7 million. Our working capital is affected primarily by fluctuations in the fair value of our commodity derivative instruments, deferred taxes associated with hedging activities, cash and cash equivalents balance and our capital spending program. As of December 31, 2006, the working capital asset balances of our cash and cash equivalents and derivative instruments were approximately $62.8 million and $20.5 million, respectively, and there was no balance for current deferred tax assets. In addition, the associated working capital liability balances for accrued liabilities and deferred tax liabilities were approximately $43.1 million and $7.7 million, respectively, as of December 31, 2006.

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***Cash Flows***

| | Successor-Consolidated | | Predecessor-Combined | |
|---|---|---|---|---|
| | Year Ended December 31, 2006 | Six Months Ended December 31, 2005 | Six Months Ended June 30, 2005 | Year Ended December 31, 2004 |
| | (In thousands) | | | |
| Cash flows provided by operating activities | $ 199,610 | $ 63,744 | $ 59,379 | $ 125,600 |
| Cash flows (used in) provided by investing activities | (236,064) | (943,246) | (30,645) | 164,433 |
| Cash flows (used in) provided by financing activities | (490) | 979,226 | (27,239) | (290,334) |
| Net (decrease) increase in cash and cash equivalents | $ (36,944) | $ 99,724 | $ 1,495 | $ (301) |

*Operating Activities.* Key drivers of net cash provided by operating activities are commodity prices, production volumes and costs and expenses, which primarily include operating costs, taxes other than income taxes, transportation expenses and administrative expenses.

Net cash provided by operating activities is largely affected by our net income, excluding non-cash expenses such as depreciation, depletion, and amortization and deferred income tax. For the year ended December 31, 2006 (Successor), our net income was $44.6 million with total production of 33.4 Bcfe. Natural gas prices averaged $7.81 per Mcf, including the effects of hedging, and oil averaged $64.01 per Bbl.

Net cash provided by operating activities for the six months ended December 31, 2005 (Successor) was $63.7 million generated from total production of 13.5 Bcfe with revenue of $113.1 and net income of $17.5 million. Natural gas prices averaged $8.23 per Mcf, including the effects of hedging, and oil averaged $59.52 per Bbl during this period.

Net cash provided from operations for the six months ended June 30, 2005 was $59.4 million generated from total production of 15.5 Bcfe with revenue of $103.8 million and net income of $30.2 million before tax. Natural gas prices averaged $6.59 per Mcf and oil averaged $49.86 per Bbl during the quarter.

Net cash provided by operating activities for the year ended December 31, 2004 were $125.6 million generated from total production of 40.9 Bcfe with revenue of $248.0 million.

*Investing Activities*. The primary driver of cash used in investing activities is capital spending.

Cash used in investing activities for the year ended December 31, 2006 was $236.1 million and related to our expenditures for the acquisition, drilling and development of oil and gas properties. These expenditures were primarily from the California, South Texas and Gulf of Mexico regions and included acquisitions of $35.3 million.

Cash used in investing activities for the six months ended December 31, 2005 was $943.2 million primarily relating to the Acquisition in the net cash amount of $910 million (excluding fees, purchase price adjustments and expenses) and $32 million in capital expenditures spent after the acquisition.

Cash used in investing activities for the six months ended June 30, 2005 was $30.6 million related to drilling and completion work and lease acquisitions less sale of assets.

Cash provided by investing activities for the year ended December 31, 2004 was $164.4 million primarily related to the completed sale of Calpine's Rocky Mountain natural gas properties that were primarily concentrated in the two geographic areas of the Colorado Piceance Basin and the New Mexico San Juan Basin. As a result of the sale, Calpine recorded income from discontinued operations, net of tax of $68.4 million.

*Financing Activities*. The primary driver of cash used in financing activities is equity transactions and issuance and repayments of debt.

Net cash used in financing activities for the year ended December 31, 2006 is primarily associated with the purchases of treasury stock surrendered by the employees to pay tax withholding upon the vesting of restricted stock awards offset by proceeds from issuances of common stock.

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Net cash provided by financing activities for the six months ended December 31, 2005 was $979.2 million. This was due to receipt of $800 million in equity offering proceeds net of $55.6 million in transaction fees and borrowings on our $325 million senior credit facility subsequently used for the acquisition of the oil and natural gas properties of Calpine, operating needs, the repayment of $85.0 million of long-term debt and $5.1 million of deferred loan costs

Net cash used in financing activities for the six months ended June 30, 2005 was comprised of repayments of notes to affiliates totaling $27.2 million.

Net cash used in financing activities for the year ended December 31, 2004 was primarily due to the cash used in discontinued operations of approximately $218.7 million, resulting from asset sales.

***Commodity Prices and Related Hedging Activities***

The energy markets have historically been very volatile and there can be no assurance that oil and natural gas prices will not be subject to wide fluctuations in the future. To mitigate our exposure to changes in commodity prices, management has adopted a policy of hedging oil and natural gas prices from time to time primarily through the use of certain derivative instruments including fixed price swaps, costless collars, and put options. Although not risk free, we believe this policy will reduce our exposure to commodity price fluctuations and thereby achieve a more predictable cash flow. Consistent with this policy, we have entered into a series of natural gas fixed-price swaps, which are intended to establish a fixed price for a significant portion of our expected natural gas production through 2009. The fixed-price swap agreements we have entered into require payments to (or receipts from) counterparties based on the differential between a fixed price and a variable price for a notional quantity of natural gas without the exchange of underlying volumes. The notional amounts of these financial instruments were based on expected proved production from existing wells at inception of the hedge instruments.

Consistent with our hedge policy, we have also entered into costless collar transactions, which are intended to establish a floor price and ceiling price for a portion of our expected production in 2007. If the floating price each month at the settlement point is greater than the ceiling price, we pay the counterparty an amount equal to the positive difference between the floating price and the ceiling price multiplied by the notional volume for the contract month. If the floating price for each month is less than the floor price, the counterparty pays us an amount equal to the positive difference between the floating price and the floor price multiplied by the notional volume for the contract month. See "Item 7A. Quantitative and Qualitative Disclosure About Market Risk".

In accordance with SFAS No. 133, as amended, all derivative instruments, not designated as a normal purchase sale, are recorded on the balance sheet at fair market value and changes in the fair market value of the derivatives are recorded each period in current earnings or other comprehensive income, depending on whether a derivative is designated as a hedge transaction, and depending on the type of hedge transaction. Our derivative contracts are cash flow hedge transactions in which we are hedging the variability of cash flow related to a forecasted transaction. Changes in the fair market value of these derivative instruments are reported in other comprehensive income and reclassified as earnings in the period(s) in which earnings are impacted by the variability of the cash flow of the hedged item. We assess the effectiveness of hedging transactions on a quarterly basis, consistent with documented risk management strategy for the particular hedging relationship. Changes in the fair market value of the ineffective portion of cash flow hedges, if any, are included in other income (expense).

Our current hedge positions are with counterparties that are lenders in our credit facilities. This allows us to securitize any margin obligation resulting from a negative change in the fair market value of the derivative contracts in connection with our credit obligations and eliminate the need for independent collateral postings. As of December 31, 2006, we had no deposits for collateral.

The following table sets forth the results of third party hedging transactions settled for the year ended December 31, 2006:

| | | For the Year Ended December 31, 2006 | For the Six Months Ended December 31, 2005 |
|---|---|---|---|
| Natural Gas | | | |
| Quantity settled (MMBtu) | | 20,075,000 | 7,956,000 |
| Increase (Decrease) in natural gas sales revenue (In thousands) | $ | 29,578 | (16,576) |

***Interest Rate Risks***

Borrowings under our Revolver and Term Loan mature on July 7, 2009 and July 7, 2010, respectively, and bear interest at a LIBOR-based rate. This exposes us to risk of earnings loss due to changes in market rates. Although we continue to evaluate the risks related to this exposure, we have not entered into any interest rate swap agreements to mitigate such risk as of December 31, 2006. If we determine the risk may become substantial and the costs are not prohibitive, we may enter into interest rate swap agreements in the future.

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***Capital Requirements***

The historical capital expenditures summary table is included in Item 1. Business and is incorporated herein by reference.

Our capital expenditures for the year ended December 31, 2006 were $240.6 million and we currently expect to expend approximately $250.0 million during 2007. We believe we have adequate expected cash flows from operations and available borrowings under our revolving credit facility to fund our budgeted capital expenditures.

***Commitments and Contingencies***

As is common within the industry, we have entered into various commitments and operating agreements related to the exploration and development of and production from proved oil and natural gas properties. It is management's belief that such commitments will be met without a material adverse effect on our financial position, results of operations or cash flows.

*Contractual Obligations.* At December 31, 2006, the aggregate amounts of our contractually obligated payment commitments for the next five years are as follows:

| | Payments Due By Period | | | | |
|---|---|---|---|---|---|
| | **Total** | **2007** | **2008 to 2009** | **2010 to 2011** | **2012 & Beyond** |
| | | | **(In thousands)** | | |
| Senior secured revolving line of credit | $ 165,000 | $ - | $ 165,000 | $ - | $ - |
| Second lien term loan | 75,000 | - | - | 75,000 | - |
| Operating leases | 14,380 | 2,421 | 4,199 | 3,782 | 3,978 |
| Interest payments on long-term debt (1) | 53,076 | 18,315 | 31,149 | 3,612 | - |
| Rig commitments | 14,895 | 14,895 | - | - | - |
| Total contractual obligations | $ 322,351 | $ 35,631 | $ 200,348 | $ 82,394 | $ 3,978 |

(1) Future interest payments were calculated based on interest rates and amounts outstanding at December 31, 2006.

*Asset retirement Obligation*. The Company also has liabilities of $10.7 million related to asset retirement obligations on its Consolidated Balance Sheet at December 31, 2006 excluded from the table above. Due to the nature of these obligations, we cannot determine precisely when the payments will be made to settle these obligations. See Note 9 of the Consolidated/Combined Financial Statements.

*Purchase and Sale Agreement with Calpine*. Under the Purchase Agreement, Calpine agreed to transfer to us certain properties. At the closing of the Acquisition in July 2005, Calpine agreed to sell but retained title to certain domestic oil and natural gas properties, subject to obtaining various third party consents or waivers of preferential purchase rights, which the parties believed at the time were required, in order to effect transfer of legal title. In July 2005, as part of the transactions undertaken in connection with closing the Acquisition, we accepted possession of and have since been operating all of the properties for which Calpine retained record legal title. We withheld approximately $75 million from the aggregate purchase price, which was the allocated dollar amount under the Purchase Agreement for the remaining properties. Subsequent to the closing of the Acquisition, with the exception of the properties subject to the preferential right to purchase, we obtained substantially all of the consents to assign for all of these remaining properties for which consents were actually required. Prior to the Calpine bankruptcy, we were prepared to consummate the assignments of legal title for these remaining properties, except those subject to properly executed preferential rights to purchase. The SEC PV-10 pretax value of these properties at December 31, 2005 was approximately $72.4 million. Based on our internal calculations, we estimate the SEC PV-10 pretax value of these properties at current market prices at December 31, 2006 to be approximately $53.0 million. We are prepared to pay Calpine the retained portion of the original purchase price, approximately $68 million, and approximately $11 million in other true-up payment obligations, all upon our receipt from Calpine of record legal title, free of any encumbrances, for that portion of these properties which are the Non-Consent Properties, subject to appropriate adjustment for the net revenues and expenses through December 15, 2005 and Calpine's performance of its obligations under the "further assurances" provisions of the Purchase Agreement. If the assignment of any remaining properties (including any leases) does not occur, the portion of the purchase price we held back pending consent or waiver will be retained by us and will be available to us for general corporate purposes.

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### *Contingencies*

We are party to various litigation matters arising out of the normal course of business. Although the ultimate outcome of each of these matters cannot be absolutely determined, and the liability the Company may ultimately incur with respect to any one of these matters in the event of a negative outcome may be in excess of amounts currently accrued with respect to such matters, management does not believe any such matters will have a material adverse effect on the Company's financial position, results of operation or cash flows.

### *Calpine Bankruptcy*

Calpine Corporation and certain of its subsidiaries filed for protection under the federal bankruptcy laws in the Bankruptcy Court on December 20, 2005. Calpine Energy Services, L.P., which filed for bankruptcy, has continued to make the required deposits into the Company's margin account and to timely pay for natural gas production it purchases from the Company's subsidiaries under various natural gas supply agreements. As part of the Acquisition, Calpine and the Company entered into a Transition Services Agreement, pursuant to which both parties were to provide certain services for the other for various periods of time. Calpine's obligation to provide services under the Transition Services Agreement ceased on July 6, 2006 and certain of Calpine's services ceased prior to the conclusion of the contract, which in neither case had any material effect on the Company. Additionally, Calpine Producer Services, L.P., which filed for bankruptcy, generally is performing its obligations under the Marketing and Services Agreement ("MSA") with the Company. The MSA was entered into by the Company and Calpine in July 2005 for the period through June 30, 2007.

The filing raises certain concerns regarding aspects of our relationship with Calpine which we will closely monitor as the Calpine bankruptcy proceeds. See further discussion of our concerns under Item 1A. Risk Factors.

### Transfers of Legal Title Pending at Calpine's Bankruptcy

At the closing of the Acquisition on July 7, 2005, we retained approximately $75 million of the purchase price in respect to Non-Consent Properties identified by Calpine at the time of the Acquisition as requiring third party consents or waivers of preferential rights to purchase that were not received before closing. Legal title for those Non-Consent Properties was not delivered at the closing. Subsequent analysis determined that a portion of the Non-Consent Properties, with an approximate allocation value of $29 million under the Purchase Agreement did not require consents or waivers. For that portion of the Non-Consent Properties for which third party consents were in fact required (having an approximate value of $39 million under the Purchase Agreement) and for which we obtained the required consents or waivers, as well as for all Non-Consent Properties that did not require consents or waivers, we believe that Calpine was and is obligated to have transferred to us the record legal title, free of any mortgages and other liens.

The approximate allocated value under the Purchase Agreement for the portion of the Non-Consent Properties subject to a third party's preferential right to purchase is $7.4 million. We have retained $7.1 million of the purchase price under the Purchase Agreement for the Non-Consent Properties subject to a third party's preferential right to purchase, and, in addition, a post-closing adjustment is required to credit us for approximately $0.3 million for a property which was transferred to us but will be transferred to the appropriate third party should it properly exercise its preferential purchase right and upon Calpine's performance of its remaining obligations under the Purchase Agreement.

We believe all conditions precedent for our receipt of record title, free of any mortgages or other liens, for substantially all of the Non-Consent Properties (excluding that portion of these properties for which a third party's preferential right to purchase was properly exercised) were satisfied earlier, and certainly no later than December 15, 2005, when we tendered once again the amounts necessary to conclude the settlement of the Non-Consent Properties.

We believe we are the equitable owner of each of the Non-Consent Properties for which Calpine was and is obligated to have transferred to us the record legal title and that such properties are not part of Calpine's bankruptcy estate. Upon our receipt from Calpine of record legal title, free of any mortgages or other liens, to these Non-Consent Properties and Calpine's performance or its further assurances required to eliminate any open issues on title to the remaining properties discussed below, we are prepared to pay Calpine approximately $68 million, subject to appropriate adjustment for the associated net revenues and expenses through December 15, 2005 and performance of Calpine's obligations under the "further assurances" provisions of the Purchase and Sale Agreement. Our statement of operations for the year ended December 31, 2006 and six months ended December 31, 2005 does not include any net revenues or production from any of the Non-Consent Properties, or those properties subject to preferential rights.

If Calpine does not provide us with record legal title, free of any mortgages for all of these properties and other liens, to any of the Non-Consent Properties (excluding that portion of these properties subject to a validly exercised third party's preferential right to purchase), we will have a total of approximately $68 million available to us for general corporate purposes, including for the purpose of acquiring additional properties. We also have approximately $7.1 million, previously withheld for that portion of the Non-Consent Properties subject to a third party's preferential right to purchase, which will also be available to us for general corporate purposes, including for the purpose of acquiring additional properties should that third party properly exercise their preferential rights.

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In addition, as to certain of the other oil and natural gas properties we purchased from Calpine in the Acquisition and for which payment was made on July 7, 2005, we will seek additional documentation from Calpine to eliminate any open issues in our title or resolve any issues as to the clarity of our ownership. Requests for additional documentation are customary in connection with transactions similar to the Acquisition. In the Acquisition, certain of these properties require ministerial governmental action approving us as qualified assignee and operator, which is typically required even though in most cases Calpine has already conveyed the properties to us free and clear of mortgages and liens by Calpine's creditors. As to certain other properties, the documentation delivered by Calpine at closing under the Purchase Agreement was incomplete. We remain hopeful that Calpine will work cooperatively with us to secure these ministerial governmental approvals and to accomplish the curative corrections for all of these properties. In addition, as to all properties acquired by us in the Acquisition, Calpine contractually agreed to provide us with such further assurances as we may reasonably request. Nevertheless, as a result of Calpine's bankruptcy filing, it remains uncertain as to whether Calpine will respond cooperatively. If Calpine does not fulfill its contractual obligations and does not complete the documentation necessary to resolve these issues, we will pursue all available remedies, including but not limited to a declaratory judgment to enforce our rights and actions to quiet title. After pursuing these matters, if we experience a loss of ownership with respect to these properties without receiving adequate consideration for any resulting loss to us, an outcome our management considers to be remote, then we could experience losses which could have a material adverse effect on our financial condition, statement of operations and cash flows.

On June 29, 2006, Calpine filed a motion in connection with its pending bankruptcy proceeding in the Bankruptcy Court seeking the entry of an order authorizing Calpine to assume certain oil and natural gas leases Calpine has previously sold or agreed to sell to us in the Acquisition, to the extent those leases constitute "unexpired leases of non-residential real property" and were not fully transferred to us at the time of Calpine's filing for bankruptcy. According to this motion, Calpine filed it in order to avoid the automatic forfeiture of any interest it may have in these leases by operation of a statutory deadline. Calpine's motion did not request that the Bankruptcy Court determine whether these properties belong to us or Calpine, but we understand it was meant to allow Calpine to preserve and avoid forfeiture under the Bankruptcy Code of whatever interest Calpine may possess, if any, in these oil and natural gas leases. We dispute Calpine's contention that it may have an interest in any significant portion of these oil and natural gas leases and intend to take the necessary steps to protect all of our rights and interest in and to the leases. On July 7, 2006, we filed an objection in response to Calpine's motion, wherein we asserted that oil and natural gas leases constitute interests in real property that are not subject to "assumption" under the Bankruptcy Code. In the objection we also requested that (a) the Bankruptcy Court eliminate from the order certain Federal offshore leases from the Calpine motion because these properties were fully conveyed to us in July 2005, and the Minerals Management Service has subsequently recognized us as owner and operator of all but three of these properties, and (b) any order entered by the Bankruptcy Court be without prejudice to, and fully preserve our rights, claims and legal arguments regarding the characterization and ultimate disposition of the remaining described oil and natural gas properties. In our objection, we also urged the Bankruptcy Court to require the parties to promptly address and resolve any remaining issues under the pre-bankruptcy definitive agreements with Calpine and proposed to the Bankruptcy Court that the parties seek arbitration (or at least mediation) to complete the following:

- Calpine's conveyance of the Non-Consent Properties to us;
- Calpine's execution of all documents and performance of all tasks required under "further assurances" provisions of the Purchase Agreement with respect to certain of the oil and natural gas properties for which we have already paid Calpine; and
- Resolution of the final amounts we are to pay Calpine, which we have concluded are approximately $79 million, consisting of roughly $68 million for the Non-Consent Properties and approximately $11 million in other true-up payment obligations.

At a hearing held on July 12, 2006, the Bankruptcy Court took the following steps:

- In response to an objection filed by the Department of Justice and asserted by the California State Lands Commission that the Debtors' Motion to Assume Non-Residential Leases and Set Cure Amounts (the "Motion"), did not allow adequate time for an appropriate response, Calpine withdrew from the list of Oil and Gas Leases that were the subject of the Motion those leases issued by the United States (and managed by the Minerals Management Service of the United States Department of Interior) (the "MMS Oil and Gas Leases") and the State of California (and managed by the California State Lands Commission) (the "CSLC Leases"). Calpine and both the Department of Justice and the State of California agreed to an extension of the existing deadline to November 15, 2006 to assume or reject the MMS Oil and Gas Leases and CSLC Leases under Section 365 of the Bankruptcy Code, to the extent the MMS Oil and Gas Leases and CSLC Leases are leases subject to Section 365. The effect of these actions was to render our objection inapplicable at that time; and

- The Bankruptcy Court also encouraged Calpine and us to arrive at a business solution to all remaining issues including approximately $68 million payable to Calpine for conveyance of the Non-Consent Properties.

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On August 1, 2006, we filed a number of proofs of claim in the Calpine bankruptcy asserting claims against a variety of Calpine debtors seeking recovery of $27.9 million in liquidated amounts as well as unliquidated damages in amounts that can not presently be determined. We continue to work with Calpine on a cooperative and expedited basis toward resolution of unresolved conveyance of properties and post-closing adjustments under the Purchase Agreement.

With respect to the stipulations between Calpine and MMS and Calpine and CSLC extending the deadline to assume or reject the MMS Oil and Gas Leases, these parties have further extended this deadline time by stipulation. The deadline was first extended to January 31, 2007 and recently was further extended to April 15, 2007 with respect to the MMS Oil and Gas Leases and April 30, 2007 with respect to the CSLC Leases. The Bankruptcy Court entered Orders related to the MMS Oil and Gas Leases and CSLC Leases which included appropriate language that we negotiated with Calpine for our protection in this regard.

Recently, Calpine sought and obtained an extension to June 20, 2007 from the Bankruptcy Court for the period in which only Calpine, exclusively, may file its plan of reorganization. While there is no assurance that Calpine will file a plan of reorganization by the deadline, or that such a plan will be approved by the creditors and the Bankruptcy Court, we remain optimistic that the issues involving conclusion of the remaining conveyances of the Non-Consent Properties and obtaining the further assurances from Calpine under the Purchase Agreement, including perhaps resolution of any and all claims, may occur during 2007.

Calpine recently requested Bankruptcy Court approval of a new credit facility which would require it to grant liens to these new lenders in all of its assets, including any interest it may still hold in any oil and gas properties it obligated itself to convey to us under the Purchase Agreement. The Bankruptcy Court entered into an Order approving Calpine’s ability to obtain this new loan which includes appropriate language that we negotiated with Calpine for our protection in this regard.

However, there can be no assurance that Calpine, its creditors or other interest holders will not challenge the fairness of the Acquisition. For a number of reasons, including our understanding of the process that Calpine followed in allowing market forces to set the purchase price for the Acquisition, we continue to believe that it is unlikely that any challenges by the Calpine debtors or their creditors to the overall fairness of the Acquisition would be successful. We will take all necessary action to ensure our rights under the Purchase Agreement, the MMS Oil and Gas Leases, the CSLC Leases and the Bankruptcy Code are fully protected.

***Environmental***

Environmental expenditures are expensed or capitalized, as appropriate, depending on their future economic benefit. Expenditures that relate to an existing condition caused by past operations, and that do not have future economic benefit, are expensed. Liabilities related to future costs are recorded on an undiscounted basis when environmental assessments and/or remediation activities are probable and the cost can be reasonably estimated. The Company performed an environmental remediation study for two sites in California and correspondingly, recorded a liability, which at December 31, 2006 and 2005 was $0.1 million and $0.7 million, respectively. The Company does not expect that the outcome of our environmental matters discussed above will have a material adverse effect on the Company’s financial position, results of operations or cash flows.

***Participation in a Regional Carbon Sequestration Partnership***

We have made preliminary preparations in connection with our participation in the United States Department of Energy’s (“DOE”) Regional Carbon Sequestration Partnership program (“WESTCARB”) with the California Energy Commission and the University of California, Lawrence Berkeley Laboratory. We have been selected by the DOE for this project. Under WESTCARB, we would be required to drill a carbon injection well, recondition an idle well for use as an observation well and provide WESTCARB with certain proprietary well data and technical assistance related to the evaluation and injection of carbon dioxide into a suitable natural gas reservoir in the Sacramento Basin. Our maximum contribution to WESTCARB is $1.0 million and will be limited to 20% of the total contributions to the project. We will not have any obligation under the WESTCARB project until it has entered into an acceptable contract and the project has obtained proper and necessary local, state and federal regulatory approvals, land use authorizations and third party property rights. No accrual was recorded at December 31, 2006 as the study is still in the preliminary stage.

***Off-Balance Sheet Arrangements***

At December 31, 2006 and 2005, we did not have any off-balance sheet arrangements.

***Forward-Looking Statements***

This report includes various “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 fact included or incorporated by reference in this report are forward-looking statements, including without limitation all statements regarding future plans, business objectives, strategies, expected future financial position or performance, expected future operational position or performance, budgets and projected costs, future competitive position, or goals and/or projections of management for future operations. In some cases, you can identify a forward-looking statement by terminology such as “may”, “will”, “could”, “should”, “expect”, “plan”, “project”, “int “anticipate”, “believe”, “estimate”, “predict”, “potential”, “pursue”, “target” or “continue”, the negative of such terms or variat thereon, or other comparable terminology.

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The forward-looking statements contained in this report are largely based on our expectations for the future, which reflect certain estimates and assumptions made by our management. These estimates and assumptions reflect our best judgment based on currently known market conditions, operating trends, and other factors. Although we believe such estimates and assumptions to be reasonable, they are inherently uncertain and involve a number of risks and uncertainties that are beyond our control. As such, management's assumptions about future events may prove to be inaccurate. For a more detailed description of the risks and uncertainties involved, see Item 1A. Risk Factors in this report. We do not intend to publicly update or revise any forward-looking statements as a result of new information, future events, changes in circumstances, or otherwise. These cautionary statements qualify all forward-looking statements attributable to us, or persons acting on our behalf. Management cautions all readers that the forward-looking statements contained in this report are not guarantees of future performance, and we cannot assure any reader that such statements will be realized or that the events and circumstances they describe will occur. Factors that could cause actual results to differ materially from those anticipated or implied in the forward-looking statements herein include, but are not limited to:

- The supply and demand for oil, natural gas, and other products and services;
- The price of oil, natural gas, and other products and services;
- Conditions in the energy markets;
- Changes or advances in technology;
- Reserve levels;
- Currency exchange rates and inflation;
- The availability and cost of relevant raw materials, goods and services;
- Commodity prices;
- Future processing volumes and pipeline throughput;
- Conditions in the securities and/or capital markets;
- The occurrence of property acquisitions or divestitures;
- Drilling and exploration risks;
- The availability and cost of processing and transportation;
- Developments in oil-producing and natural gas-producing countries;
- Competition in the oil and natural gas industry;
- The ability and willingness of our current or potential counterparties or vendors to enter into transactions with us and/or to fulfill their obligations to us;
- Our ability to access the capital markets on favorable terms or at all;

- Our ability to obtain credit and/or capital in desired amounts and/or on favorable terms;

- Present and possible future claims, litigation and enforcement actions;

- Effects of the application of applicable laws and regulations, including changes in such regulations or the interpretation thereof;

- Relevant legislative or regulatory changes, including retroactive royalty or production tax regimes, changes in environmental regulation, environmental risks and liability under federal, state and foreign environmental laws and regulations;

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- General economic conditions, either internationally, nationally or in jurisdictions affecting our business;
- The amount of resources expended in connection with Calpine's bankruptcy, including costs for lawyers, consultant experts and related expenses, as well as all lost opportunity costs associated with our internal resources dedicated to these matters;
- Disputes with mineral lease and royalty owners regarding calculation and payment of royalties;
- The weather, including the occurrence of any adverse weather conditions and/or natural disasters affecting our business; and
- Any other factors that impact or could impact the exploration of oil or natural gas resources, including but not limited to the geology of a resource, the total amount and costs to develop recoverable reserves, and legal title, regulatory, natural gas administration, marketing and operational factors relating to the extraction of oil and natural gas.

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**Item 7A. Quantitative and Qualitative Disclosures About Market Risk**

The primary objective of the following information is to provide forward-looking quantitative and qualitative information about our potential exposure to market risks. The term “market risk” refers to the risk of loss arising from adverse changes in oil and natural gas prices and interest rates. The disclosures are not meant to be precise indicators of expected future losses, but rather indicators of reasonable possible losses. This forward-looking information provides indicators of how we view and manage our ongoing market risk exposures. All of our market risk sensitive instruments were entered into for purposes other than speculative trading.

*Commodity Price Risk.* Our major market risk exposure is in the pricing of our oil and natural gas production. Realized pricing is primarily driven by the prevailing worldwide price for crude oil and spot market prices applicable to our U.S. natural gas production. Pricing for oil and natural gas production has been volatile and unpredictable for several years, and we expect this volatility to continue in the future. The prices we receive for production depend on many factors outside of our control. Based on average daily production for the year ended December 31, 2006, our annual income before income taxes would change by approximately $3.0 million for each $0.10 per Mcfe change in natural gas prices and approximately $0.6 million for each $1.00 per Bbl change in crude oil prices.

We use derivative transactions to manage exposure to commodity prices. Our objectives for holding derivative instruments are to achieve a consistent level of cash flow to support a portion of our planned capital spending. Our use of derivative transactions for hedging activities could materially affect our results of operations, in particular quarterly or annual periods since such instruments can limit our ability to benefit from favorable price movements. We do not enter into derivative instruments for speculative purposes.

We believe the use of derivative transactions, although not free of risk, allows us to reduce our exposure to oil and natural gas sales price fluctuations and thereby achieve a more predictable cash flow. While the use of derivative instruments limits the downside risk of adverse price movements, their use may also limit future revenues from favorable price movements. Moreover, our derivative contracts generally do not apply to all of our production and thus provide only partial price protection against declines in commodity prices. We expect that the amount of our derivative contracts will vary from time to time.

Our fixed-price swap agreements are used to fix the sales price for our anticipated future oil and natural gas production. Upon settlement, we receive a fixed price for the hedged commodity and pay our counterparty a floating market price, as defined in each instrument. These instruments are settled monthly. When the floating price exceeds the fixed price for a contract month, we pay our counterparty. When the fixed price exceeds the floating price, our counterparty is required to make a payment to us. We have designated these swaps as cash flow hedges.

As of December 31, 2006, we had the following financial fixed price swap positions outstanding with average underlying prices that represent hedged prices of commodities at various market locations:

| Settlement Period | Derivative Instrument | Hedge Strategy | Notional Daily Volume MMBtu | Total of Notional Volume MMBtu | Average Underlying Prices MMBtu | Total of Proved Natural Gas Production Hedged (1) | Fair Market Value Gain/(Loss) (In thousands) |
|---|---|---|---|---|---|---|---|
| 2007 | Swap | Cash flow | 49,341 | 18,009,500 | $ 7.76 | 40% | $ 17,216 |
| 2008 | Swap | Cash flow | 49,909 | 18,266,616 | 7.62 | 44% | (4,440) |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| 2009 | Swap | Cash flow | 26,141 | 9,541,465 | 6.99 | 26% | | (5,962) |
| | | | | 45,817,581 | | | $ | 6,814 |

(1) Estimated based on net gas reserves presented in the December 31, 2006 Netherland, Sewell & Associates, Inc. reserve report.

We have also entered into costless collar transactions, which are intended to establish a floor price and ceiling price for a portion of our expected production in 2007. If the floating price each month at the settlement point is greater than the ceiling price, we pay the counterparty an amount equal to the positive difference between the floating price and the ceiling price multiplied by the notional volume for the contract month. If the floating price for each month is less than the floor price, the counterparty pays us an amount equal to the positive difference between the floating price and the floor price multiplied by the notional volume for the contract month.

The following table describes our open costless collar transactions at December 31, 2006 by associated notional volumes and contracted ceiling and floor price at various market locations:

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| Settlement Period | Derivative Instrument | Hedge Strategy | Notional Daily Volume MMBtu | Total of Notional Volume MMBtu | Average Floor Price MMBtu | Average Ceiling Price MMBtu | Fair Market Value Gain/(Loss) (In thousands) |
|---|---|---|---|---|---|---|---|
| 2007 | Costless Collar | Cash flow | 10,000 | 3,650,000 | $ 7.19 | $ 10.03 | $ 3,322 |
| | | | | 3,650,000 | | | $ 3,322 |

The total of proved natural gas production hedged in 2006 for the costless collars is approximately 8% based on the December 31, 2006 reserve report prepared by Netherland, Sewell & Associates, Inc.

*Interest Rate Risks.* In July 2005, we entered into our credit facilities including (1) a senior secured revolving line of credit in the aggregate amount of up to $400 million (the “Revolver”), and (2) a senior secured second lien term loan, initially, in the aggregate amount of $100 million (the “Term Loan”). Both the Revolver and the Term Loan were amended and syndicated on September 27, 2005.

Availability under the Revolver is restricted to a borrowing base calculation of value assigned to proved oil and natural gas reserves. The initial borrowing base was $275 million and was reset to $325 million as of the syndication date as a result of the derivative transactions and the favorable effects of our underwriters exercising the over-allotment option we granted in connection with our sale of 45,312,500 shares of our common stock, through which we received $70 million of funds (net of transaction fees), which were used to repay $60.0 million of borrowings under the Revolver in July 2005 and the remainder for unspecified operating costs of our oil and natural gas properties and general and administrative costs from our oil and natural gas operations. The borrowing base is subject to review and adjustment on a semi-annual basis and other interim adjustments, including adjustments based on our derivative arrangements. Amounts outstanding under the Revolver bear interest at specified margins over the London Interbank Offered Rate (“LIBOR”) of 1.25% to 2.00%, based on facility utilization. The Revolver will mature on July 7, 2009.

The Term Loan initially in the amount of $100 million was reduced to $75 million on the syndication date of September 27, 2005. Borrowings under the Term Loan initially bore interest at LIBOR plus 5.00%. In September 2005, $25 million of borrowings under the Term Loan were repaid. As a result of the derivative transactions and the favorable effect of our private equity placement, as described above, the interest rate for the second lien term loan has been reduced to LIBOR plus 4.00%. The Term Loan is collateralized by a second lien on all assets securing the Revolver. The Term Loan will mature on July 7, 2010.

We had availability under the facility of $159.0 million as of December 31, 2006. A one hundred basis point increase in each of the LIBOR rate and federal funds rate as of December 31, 2006 and 2005 for both our revolver of credit and term debt would result in an estimated $2.4 million increase, respectively, in annual interest expense.

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**Item 8. Financial Statements and Supplementary Data**

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**Report of Independent Registered Public Accounting Firm**

To the Board of Directors
and Stockholders of Rosetta Resources Inc.:

In our opinion, the consolidated balance sheets as of December 31, 2006 and 2005 and the related consolidated statements of operations, of cash flows and of changes in stockholders' equity and comprehensive income for the year ended December 31, 2006 and the six months ended December 31, 2005 present fairly, in all material respects, the consolidated financial position of Rosetta Resources Inc. and its subsidiaries (successor, the "Company") at December 31, 2006 and 2005 and the results of their operations and their cash flows for the year ended December 31, 2006 and the six months ended December 31, 2005 in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As described in Note 3 to the consolidated financial statements, the Company changed its method of accounting for stock-based compensation effective January 1, 2006.

As described in Note 11 to the consolidated financial statements, the Company's former parent filed bankruptcy subsequent to the Company's acquisition of the oil and natural gas business of Calpine Corporation and Affiliates.

/s/ PricewaterhouseCoopers LLP

March 15, 2007
Houston, Texas

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**Report of Independent Registered Public Accounting Firm**

To the Board of Directors
and Stockholders of Rosetta Resources Inc.:

In our opinion, the combined statements of operations, of cash flows and of changes in owner's net investment for the six months ended June 30, 2005 and the year ended December 31, 2004 present fairly, in all material respects, the results of operations and cash flows of the Domestic Oil & Natural Gas Properties of Calpine Corporation and Affiliates (predecessor) for the six months ended June 30, 2005 and the year ended December 31, 2004 in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As described in Note 17 to the combined financial statements, the Company has significant transactions and relationships with related parties. Because of these relationships, it is possible that the terms of these transactions are not the same as those that would result from transactions among wholly unrelated parties.

/s/ PricewaterhouseCoopers LLP

April 19, 2006
Houston, Texas

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**Rosetta Resources Inc.**
**Consolidated Balance Sheet**
**(In thousands, except share amounts)**

| | December 31, 2006 | December 31, 2005 |
|---|---|---|
| **Assets** | | |
| Current assets: | | |
| Cash and cash equivalents | $ 62,780 | $ 99,724 |
| Accounts receivable | 36,408 | 40,051 |
| Derivative instruments | 20,538 | 1,110 |
| Deferred income taxes | - | 10,962 |
| Income tax receivable | - | 6,000 |
| Prepaid expenses | 8,761 | 8,511 |
| Other current assets | 2,965 | 900 |
| Total current assets | 131,452 | 167,258 |
| Oil and natural gas properties, full cost method, of which $37.8 million at December 31, 2006 and $30.6 million at December 31, 2005 were excluded from amortization | 1,223,337 | 973,185 |
| Other | 4,562 | 2,912 |
| | 1,227,899 | 976,097 |
| Accumulated depreciation, depletion, and amortization | (145,289) | (40,161) |
| Total property and equipment, net | 1,082,610 | 935,936 |
| Deferred loan fees | 3,375 | 4,555 |
| Deferred income taxes | - | 8,594 |
| Other assets | 1,968 | 2,926 |
| Total other assets | 5,343 | 16,075 |
| Total assets | $ 1,219,405 | $ 1,119,269 |
| | | |
| **Liabilities and Stockholders' Equity** | | |
| Current liabilities: | | |
| Accounts payable | $ 23,040 | $ 13,442 |
| Accrued liabilities | 43,099 | 28,397 |
| Royalties payable | 9,010 | 15,511 |
| Derivative instruments | - | 29,957 |
| Prepayment on gas sales | 17,868 | 14,528 |
| Deferred income taxes | 7,743 | - |
| Total current liabilities | 100,760 | 101,835 |
| Long-term liabilities: | | |
| Derivative instruments | 11,014 | 52,977 |
| Long-term debt | 240,000 | 240,000 |
| Asset retirement obligation | 10,253 | 9,034 |
| Deferred income taxes | 35,089 | - |
| Total liabilities | 397,116 | 403,846 |
| Commitments and contingencies (Note 11) | | |
| Stockholders' equity: | | |
| Common stock, $0.001 par value; authorized 150,000,000 shares; issued 50,405,794 shares and 50,003,500 shares at December 31, 2006 and December 31, 2005, respectively | 50 | 50 |

| | | | | |
|---|---|---|---|---|
| Additional paid-in capital | | 755,343 | | 748,569 |
| Treasury stock, at cost; 85,788 and no shares at December 31, 2006 and December 31, 2005, respectively | | (1,562) | | - |
| Accumulated other comprehensive income (loss) | | 6,315 | | (50,731) |
| Retained earnings | | 62,143 | | 17,535 |
| Total stockholders' equity | | 822,289 | | 715,423 |
| Total liabilities and stockholders' equity | $ | 1,219,405 | $ | 1,119,269 |

The accompanying notes to the financial statements are an integral part hereof.

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**Rosetta Resources Inc.**
**Consolidated/Combined Statement of Operations**
**(In thousands, except per share amounts)**

| | Successor-Consolidated | | Predecessor - Combined | |
|---|---|---|---|---|
| | Year Ended December 31, 2006 | Six Months Ended December 31, 2005 | Six Months Ended June 30, 2005 | Year Ended December 31, 2004 |
| Revenues: | | | | |
| Natural gas sales | $ 236,496 | $ 102,058 | $ 13,713 | $ 34,348 |
| Oil sales | 35,267 | 11,046 | 8,166 | 23,443 |
| Oil and natural gas sales to affiliates | - | - | 81,952 | 190,215 |
| Total revenues | 271,763 | 113,104 | 103,831 | 248,006 |
| Operating Costs and Expenses: | | | | |
| Lease operating expense | 36,273 | 15,674 | 16,629 | 30,785 |
| Depreciation, depletion, and amortization | 105,886 | 40,500 | 30,679 | 81,590 |
| Exploration expense | - | - | 2,355 | 5,352 |
| Dry hole costs | - | - | 1,962 | 2,088 |
| Impairment | - | - | - | 202,120 |
| Treating and transportation | 2,544 | 1,286 | 1,998 | 3,509 |
| Affiliated marketing fees | - | - | 913 | 1,887 |
| Marketing fees | 2,257 | 1,379 | - | - |
| Production taxes | 6,433 | 3,975 | 2,755 | 4,322 |
| General and administrative costs | 33,233 | 14,687 | 9,677 | 19,416 |
| Total operating costs and expenses | 186,626 | 77,501 | 66,968 | 351,069 |
| Operating income (loss) | 85,137 | 35,603 | 36,863 | (103,063) |
| | | | | |
| Other (income) expense | | | | |
| Interest expense with affiliates, net of interest capitalized | **-** | - | 6,995 | 28,034 |
| Interest expense, net of interest capitalized | 17,428 | 8,216 | - | - |
| Interest (income) | (4,503) | (1,837) | (516) | (726) |
| Other (income) expense, net | (40) | 152 | 207 | (3,010) |
| Total other expense | 12,885 | 6,531 | 6,686 | 24,298 |
| | | | | |
| Income (loss) before provision for income taxes | 72,252 | 29,072 | 30,177 | (127,361) |
| Provision (benefit) for income taxes | 27,644 | 11,537 | 11,496 | (48,525) |
| Income (loss) from continuing operations | 44,608 | 17,535 | 18,681 | (78,836) |
| Income from discontinued operations, net of tax | - | - | - | 68,440 |
| **Net income (loss)** | $ 44,608 | $ 17,535 | $ 18,681 | $ (10,396) |

| | | | | |
|---|---|---|---|---|
| **Basic net income (loss) per share:** | | | | |
| Income (loss) from continuing operations | $ 0.89 | $ 0.35 | $ 0.37 | $ (1.58) |
| Income from discontinued operations | - | - | - | 1.37 |
| Net income (loss) | $ 0.89 | $ 0.35 | $ 0.37 | $ (0.21) |
| | | | | |
| **Diluted net income (loss) per share:** | | | | |
| Income (loss) from continuing operations | $ 0.88 | $ 0.35 | $ 0.37 | $ (1.58) |
| Income from discontinued operations | - | - | - | 1.37 |
| Net income (loss) | $ 0.88 | $ 0.35 | $ 0.37 | $ (0.21) |
| | | | | |
| **Weighted average shares outstanding:** | | | | |
| Basic | 50,237 | 50,003 | 50,000 | 50,000 |
| Diluted | 50,408 | 50,189 | 50,160 | 50,000 |

The accompanying notes to the financial statements are an integral part hereof.

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**Rosetta Resources Inc.**
**Consolidated/Combined Statement of Cash Flows**
**(In thousands)**

| | Successor-Consolidated | | Predecessor-Combined | |
|---|---|---|---|---|
| | Year Ended December 31, 2006 | Six Months Ended December 31, 2005 | Six Months Ended June 30, 2005 | Year Ended December 31, 2004 |
| Cash flows from operating activities | | | | |
| Net income (loss) | $ 44,608 | $ 17,535 | $ 18,681 | $ (10,396) |
| Income (loss) from discontinued operations, net of taxes | - | - | - | (68,440) |
| Net income (loss) from continuing operations | 44,608 | 17,535 | 18,681 | (78,836) |
| Adjustments to reconcile net income to net cash from operating activities | | | | |
| Depreciation, depletion and amortization | 105,886 | 40,500 | 30,679 | 81,590 |
| Affiliate interest expense | - | - | (6,995) | (28,034) |
| Impairment | - | - | - | 202,120 |
| Deferred income taxes | 27,472 | 11,537 | 2,874 | (137,838) |
| Amortization of deferred loan fees recorded as interest expense | 1,180 | 590 | - | - |
| Income from unconsolidated investments | (171) | (241) | (161) | (324) |
| Stock compensation expense | 5,702 | 4,248 | - | - |
| Other non-cash charges | - | - | 99 | 4,856 |
| Change in operating assets and liabilities: | | | | |
| Accounts receivable | 3,643 | (40,051) | 2,378 | 5,486 |
| Accounts receivable from affiliates | - | - | 6,298 | (293) |
| Income taxes receivable | 6,000 | (6,000) | - | - |
| Other assets | (624) | (11,137) | 2,563 | (5,267) |
| Accounts payable | 8,765 | 13,442 | (4,494) | 1,517 |
| Accrued liabilities | 310 | 3,282 | 241 | (6,266) |
| Royalties payable | (3,161) | 30,039 | (1,406) | (6,842) |
| Income taxes payable | - | - | 8,622 | 89,313 |
| Cash provided by continuing operating activities | 199,610 | 63,744 | 59,379 | 121,182 |
| Cash provided by discontinued operations | - | - | - | 4,418 |
| Net cash provided by operating activities | 199,610 | 63,744 | 59,379 | 125,600 |
| Cash flows from investing activities | | | | |

| | | | | |
|---|---|---|---|---|
| Acquisition, net of cash acquired | - | (910,064) | - | - |
| Purchases of property and equipment | (236,579) | (32,994) | (32,202) | (68,386) |
| Disposals of property and equipment | 30 | 13 | 1,447 | 14,536 |
| Deposits | 50 | (201) | - | - |
| Other | 435 | - | 110 | (83) |
| Cash used in continuing investing activities | (236,064) | (943,246) | (30,645) | (53,933) |
| Cash provided by discontinued operations | - | - | - | 218,366 |
| Net cash (used in) provided by investing activities | (236,064) | (943,246) | (30,645) | 164,433 |

(continued)

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**Rosetta Resources Inc.**
**Consolidated/Combined Statement of Cash Flows (Continued)**
**(In thousands)**

| | Successor-Consolidated | | Predecessor-Combined | |
|---|---|---|---|---|
| | Year Ended December 31, 2006 | Six Months Ended December 31, 2005 | Six Months Ended June 30, 2005 | Year Ended December 31, 2004 |
| Cash flows from financing activities | | | | |
| Equity offering proceeds | - | 800,000 | - | - |
| Equity offering transaction fees | 268 | (55,629) | - | - |
| Borrowings on term loan | - | 100,000 | - | - |
| Payments on term loan | - | (25,000) | - | - |
| Borrowings on revolving credit facility | - | 225,000 | - | - |
| Payments on revolving credit facility | - | (60,000) | - | - |
| Loan fees | - | (5,145) | - | - |
| Capital lease | - | - | - | (1,420) |
| Notes payable to affiliates | - | - | (27,239) | (70,226) |
| Proceeds from issuances of common stock | 804 | - | - | - |
| Purchases of treasury stock | (1,562) | - | - | - |
| Cash (used in) provided by continuing financing activities | (490) | 979,226 | (27,239) | (71,646) |
| Cash used in discontinued operations | - | - | - | (218,688) |
| Net cash (used in) provided by financing activities | (490) | 979,226 | (27,239) | (290,334) |
| | | | | |
| Net (decrease) increase in cash | (36,944) | 99,724 | 1,495 | (301) |
| Cash and cash equivalents, beginning of period | 99,724 | - | - | 301 |
| Cash and cash equivalents, end of period | $ 62,780 | $ 99,724 | $ 1,495 | $ - |
| | | | | |
| Supplemental disclosures: | | | | |
| Cash paid for interest expense, net of capitalized Interest | $ 17,875 | $ (8,057) | $ - | $ - |
| Cash paid for tax | $ 172 | $ 6,000 | $ - | $ - |
| Supplemental non-cash disclosures: | | | | |
| Oil and gas properties acquired from affiliates in exchange for notes payable to affiliates | $ - | $ - | $ - | $ 10,100 |
| Capital expenditures included in accrued liabilities | $ 5,589 | $ 33,470 | $ - | $ - |

| | | | | |
|---|---|---|---|---|
| Accrued purchase price adjustment | $ 11,400 | $ - | $ - | $ - |

The accompanying notes to the financial statements are an integral part hereof

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**Rosetta Resources Inc.**
**Consolidated/Combined Statement of Stockholders' Equity and Owner's Net Investment**
**(In thousands, except per share amounts)**

| | Common Stock | | Additional | Accumulated Other | Treasury Stock | | | Total Stockholders' Equity & Owner's Net |
|---|---|---|---|---|---|---|---|---|
| **Predecessor** | **Shares** | **Amount** | **Paid-In Capital** | **Comprehensive (Loss)** | **Shares** | **Amount** | **Retained Earnings** | **Investment** |
| Balance January 1, 2004 | - | $ - | $ - | $ - | - | $ - | $ - | $ 233,847 |
| Net Loss | - | - | - | - | - | - | - | (10,396) |
| Balance December 31, 2004 | - | - | - | - | - | - | - | 223,451 |
| Net Income | - | - | - | - | - | - | - | 18,681 |
| Balance June 30, 2005 | - | $ - | $ - | $ - | - | $ - | $ - | $ 242,132 |
| | | | | | | | | |
| **Successor** | | | | | | | | |
| Balance July 1, 2005 | - | $ - | $ - | $ - | - | $ - | $ - | $ - |
| Issuance of common stock, net of offering costs | 50,003,500 | 50 | 744,321 | - | - | - | - | 744,371 |
| Vesting of restricted stock | - | - | 4,248 | - | - | - | - | 4,248 |
| Comprehensive Income: | | | | | | | | |
| Net Income | - | - | - | - | - | - | 17,535 | 17,535 |
| Change in fair value of derivative hedging instruments | - | - | - | (98,400) | - | - | - | (98,400) |
| Hedge settlements reclassified to income | - | - | - | 16,576 | - | - | - | 16,576 |
| Tax (provision)/benefit related to cash flow hedges | - | - | - | 31,093 | - | - | - | 31,093 |
| Comprehensive Income | - | - | - | | - | - | - | (33,196) |
| Balance December 31, 2005 | 50,003,500 | 50 | 748,569 | (50,731) | - | - | 17,535 | 715,423 |
| Equity offering - transaction fees | - | - | 268 | - | - | - | - | 268 |
| Stock issued options | 49,896 | - | 804 | - | - | - | - | 804 |
| Treasury stock - employee tax payment | - | - | | - | 85,788 | (1,562) | - | (1,562) |
| Stock-based compensation expense | - | - | 5,702 | - | - | - | - | 5,702 |
| Vesting of restricted stock | 352,398 | - | - | - | - | - | - | - |
| Comprehensive Income: | | | | | | | | |
| Net Income | - | - | - | - | - | - | 44,608 | 44,608 |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| Change in fair value of derivative hedging instruments | - | - | - | 121,540 | - | - | - | 121,540 |
| Hedge settlements reclassified to income | - | - | - | (29,578) | - | - | - | (29,578) |
| Tax (provision)/benefit related to cash flow hedges | - | - | - | (34,916) | - | - | - | (34,916) |
| Comprehensive Income | - | - | - | - | - | - | - | 101,654 |
| Balance December 31, 2006 | 50,405,794 | $ 50 | $ 755,343 | $ 6,315 | 85,788 | $ (1,562) | $ 62,143 | $ 822,289 |

The accompanying notes to the financial statements are an integral part hereof

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**Rosetta Resources Inc.**

**Notes to Consolidated/Combined Financial Statements**

## (1) Organization and Operations of the Company

*Nature of Operations.* Rosetta Resources, Inc. (together with its consolidated subsidiaries, the "Company") was formed in June 2005 to acquire Calpine Natural Gas L.P. the domestic oil and natural gas business formerly owned by Calpine Corporation and affiliates ("Calpine"). The Company ("Successor") acquired Calpine Natural Gas L.P. ("Predecessor") in July 2005 (hereinafter, the "Acquisition") and together with all subsequently acquired oil and gas properties is engaged in oil and natural gas exploration, development, production and acquisition activities in the United States. The Company's main operations are primarily concentrated in the Sacramento Basin of California, the Lobo and Perdido Trends in South Texas, the State Waters of Texas, the Gulf of Mexico and the Rocky Mountains.

Certain reclassifications of prior year balances have been made to conform such amounts to corresponding 2006 classifications. These reclassifications have no impact on net income.

## (2) Acquisition of Calpine Oil and Natural Gas Business

On July 7, 2005, in the Acquisition, the Company acquired substantially all of the oil and natural gas business of Calpine and certain of its subsidiaries, excluding certain non-consent properties described below, for approximately $910 million. The Acquisition was funded with the issuance of common stock totaling $725 million and $325 million of debt from the Company's credit facilities. The transaction was accounted for under the purchase method in accordance with Statement of Financial Accounting Standards ("SFAS") No.141. The results of operations were included in the Company's financial statements effective July 1, 2005 as the operating results in the intervening period were not significant. The purchase price in the Acquisition was calculated as follows (In thousands):

| | |
|---|---|
| Cash from equity offering | $ 725,000 |
| Proceeds from revolver | 225,000 |
| Proceeds from term loan | 100,000 |
| Other purchase price costs | (53,389) |
| Transaction adjustments (purchase price adjustments) | (11,556) |
| Transaction adjustments (non-consent properties) | (74,991) |
| Initial purchase price | $ 910,064 |

Other purchase price costs relate primarily to professional fees of $3.9 million and other direct transaction costs of $49.5 million.

The transaction adjustments (purchase price adjustments) referred to above are an amount agreed upon by Calpine and the Company to cover potential costs and/or revenues to be adjusted to actual upon the final settlement.

Transaction adjustments (non-consent properties) referred to above relate to the non-consent properties, which are those properties Calpine believed at the time of the Acquisition required third party consents or waivers of preferential purchase rights in order to effect the transfer of record legal title from Calpine to the Company or to Calpine entities acquired by the Company in the Acquisition ("Non-Consent Properties"). At July 7, 2005, the Company withheld approximately $75 million of the purchase price with respect to the Non-Consent Properties. A third party has purportedly exercised a preferential right to purchase certain of the Non-Consent Properties but which we have not been able to verify was validly exercised. Assuming such preferential rights transaction is consummated, these properties will not be conveyed to the Company, and the purchase price of the remaining Non-Consent Properties will be reduced by approximately $7.4 million. Despite Calpine's bankruptcy filing, management believes that it remains likely that conveyance to the Company of legal title to substantially all of the remaining Non-Consent Properties will occur. Upon conveyance of the legal title of the remaining Non-Consent Properties and Calpine's performance of its "further assurances" under the Purchase Agreement, approximately $68 million, the balance of the purchase price, will be paid to Calpine and will be incremental to the purchase price of $910 million. The Company has excluded the effects of the operating results for the Non-Consent Properties from the Company's actual results for the year ended December 31, 2006 and for the six months ended December 31, 2005. If the assignment of legal title of the remaining Non-Consent Properties does not occur, the portion of the purchase price the Company withheld pending obtaining consent or waivers for these properties will be available to the Company for general corporate purposes or to acquire other properties.

The following is the allocation of the purchase price to specific assets acquired and liabilities assumed based on estimates of the fair values and costs (In thousands). There was no goodwill associated with the transaction.

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| | |
|---|---|
| Current assets | $ 1,794 |
| Non-current assets | 5,087 |
| Properties, plant and equipment | 925,141 |
| Current liabilities | (14,390) |
| Long-term liabilities | (7,568) |
| | $ 910,064 |

In addition to the $68 million that will be payable to Calpine if and when title is obtained by the Company for the remaining Non-Consent Properties and if Calpine provides further assurances to eliminate any open issues on title to the remaining properties that may require further documentation, the Company's revised Final Settlement Statement includes the proposed cash payment to Calpine of approximately $11 million arising from net revenues that were estimated and withheld at the closing of the Acquisition, which is recorded as an accrued liability on the Consolidated Balance Sheet as of December 31, 2006.

The unaudited pro forma information below for the years ended December 31, 2005 and 2004 assume the acquisition of Calpine's domestic oil and natural gas business and the related financings occurred at the beginning of the periods presented. The Company believes the assumptions used provide a reasonable basis for presenting the significant effects directly attributable to such transactions. The unaudited pro forma financial statements do not purport to represent what the Company's results of operations would have been if such transactions had occurred on such date.

| | **Year Ended December 31,** | |
|---|---|---|
| | **2005** | **2004** |
| | **(In thousands, except per share amounts) (Unaudited)** | |
| Revenues | $ 207,501 | $ 223,168 |
| Net income | 26,437 | 45,882 |
| Basic earnings per common share | 0.53 | 0.92 |
| Diluted earnings per common share | $ 0.53 | $ 0.91 |

## (3) Summary of Significant Accounting Policies

All significant accounting policies discussed below are applicable to both the Company and Calpine unless otherwise noted below.

*Principles of Consolidation/Combination and Basis of Presentation*

The Predecessor combined financial statements for the six months ended June 30, 2005 and year ended December 31, 2004 have been prepared from the historical accounting records of the domestic oil and natural gas business of Calpine and are presented on a carve-out basis to include the historical operations of the domestic oil and natural gas business. The domestic oil and natural gas business of Calpine was separately accounted for and managed through direct and indirect subsidiaries of Calpine. The combined financial information included herein includes certain allocations based on the historical activity levels to reflect the combined financial statements in accordance with accounting principles generally accepted in the United States of America and may not necessarily reflect the financial position, results of operations and cash flows of the Company in the future or as if the Company had existed as a separate, stand-alone business during the period presented. The allocations consist of general and administrative expenses such as employee payroll and related benefit costs and building lease expense, which were incurred on behalf of the Predecessor. The allocations have been made on a reasonable basis and have been consistently applied for the periods presented.

The accompanying consolidated financial statements for the year ended December 31, 2006 and for the six months ended December 31, 2005 contain the accounts of Rosetta Resources Inc. and its wholly owned subsidiaries after eliminating all significant intercompany balances and transactions.

*Use of Estimates in Preparation of Financial Statements*

The preparation of the Consolidated/Combined Financial Statements in conformity with accounting principles generally accepted in the United States of America 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 revenue and expense during the reporting period. Certain accounting policies involve judgments and uncertainties to such an extent that there is reasonable likelihood that materially different amounts could have been reported under different conditions, or if different assumptions had been used. The Company evaluates their estimates and assumptions on a regular basis. The Company bases their estimates on historical experience and various other assumptions that are believed to be reasonable under the circumstances, the results of which form the basis for making judgments about the carrying values of assets and liabilities that are not readily apparent from other sources. Actual results may differ from these estimates and assumptions used in preparation of the Company’s financial statements. The most significant estimates with regard to these financial statements relate to the provision for income taxes, the outcome of pending litigation, future development and abandonment costs, estimates to certain oil and gas revenues and expenses and estimates of proved oil and natural gas reserve quantities used to calculate depletion, depreciation and impairment of proved oil and natural gas properties and equipment.

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*Cash and Cash Equivalents*

The Company considers all highly liquid investments with an original maturity of three months or less to be cash equivalents.

*Allowance for Doubtful Accounts*

The Company regularly reviews all aged accounts receivables for collectability and establishes an allowance as necessary for balances greater than 90 days outstanding. It is the Company's belief that there are no balances in accounts receivable that will not be collected and that an allowance was unnecessary at December 31, 2006 and December 31, 2005.

*Property, Plant and Equipment, Net*

In connection with the Company's separation from Calpine, the Company adopted the full cost method of accounting for oil and natural gas properties beginning July 1, 2005. Under the full cost method, all costs incurred in acquiring, exploring and developing properties within a relatively large geopolitical cost center are capitalized when incurred and are amortized as mineral reserves in the cost center as produced, subject to a limitation that the capitalized costs not exceed the value of those reserves. In some cases, however, certain significant costs, such as those associated with offshore U.S. operations, are deferred separately without amortization until the specific property to which they relate is found to be either productive or nonproductive, at which time those deferred costs and any reserves attributable to the property are included in the computation of amortization in the cost center. All costs incurred in oil and natural gas producing activities are regarded as integral to the acquisition, discovery and development of whatever reserves ultimately result from the efforts as a whole, and are thus associated with the Company's reserves. The Company capitalizes internal costs directly identified with acquisition, exploration and development activities. The Company capitalized $3.4 million and $1.7 million of internal costs for the year ended December 31, 2006 and the six months ended December 31, 2005, respectively. Unevaluated costs are excluded from the full cost pool and are periodically evaluated for impairment at which time they are transferred to the full cost pool to be amortized. Upon evaluation, costs associated with productive properties are transferred to the full cost pool and amortized. Gains or losses on the sale of oil and natural gas properties are generally included in the full cost pool unless a significant portion of the pool is sold.

The Company assesses the impairment for oil and natural gas properties for the full cost pool quarterly using a ceiling test to determine if impairment is necessary. If the net capitalized costs of oil and natural gas properties exceed the cost center ceiling, the Company is subject to a ceiling test write-down to the extent of such excess. A ceiling test write-down is a charge to earnings and cannot be reinstated even if the cost ceiling increases at a subsequent reporting date. If required, it would reduce earnings and impact shareholders' equity in the period of occurrence and result in a lower depreciation, depletion and amortization expense in the future.

Our ceiling test computation was calculated using hedge adjusted market prices at December 31, 2006 which were based on a Henry Hub price of $5.64/ MMBtu and a West Texas Intermediate oil price of $60.50/Bbl (adjusted for basis and quality differentials). The use of these prices would have resulted in an after-tax writedown of $85 million at December 31, 2006. Cash flow hedges of natural gas production in place at December 31, 2006 increased the calculated ceiling value by approximately $47 million (net of tax). However, subsequent to December 31, 2006 the market price for Henry Hub increased to $7.52 MMBtu and the price for West Texas Intermediate increased to $61.84/Bbl, and utilizing these prices our net capitalized costs of oil and gas properties exceeded the ceiling amount. As a result no writedown was recorded at December 31, 2006. The ceiling value calculated using subsequent prices includes approximately $6 million related to the positive effects of future cash flow hedges of natural gas production. Due to the volatility of commodity prices, should natural gas prices decline in the future, it is possible that a writedown could occur.

No impairment charge was recorded for the six months ended December 31, 2005.

Calpine followed the successful efforts method of accounting for oil and natural gas activities. Under the successful efforts method, lease acquisition costs and all development costs were capitalized. Exploratory drilling costs were capitalized until the results were determined. If proved reserves were not discovered, the exploratory drilling costs were expensed. Other exploratory costs were expensed as incurred. Interest costs related to financing major oil and natural gas projects in progress were capitalized until the projects were evaluated or until the projects were substantially complete and ready for their intended use if the projects were evaluated as successful. Calpine also capitalized internal costs directly identified with acquisition, exploration and development activities and did not include any costs related to production, general corporate overhead or similar activities. The provision for depreciation, depletion, and amortization was based on the capitalized costs as determined above, plus future abandonment costs net of salvage value, using the unit of production method with lease acquisition costs amortized over total proved reserves and other costs amortized over proved developed reserves.

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Calpine assessed the impairment for oil and natural gas properties on a field by field basis periodically (at least annually) to determine if impairment of such properties was necessary. Management utilized its year-end reserve report prepared by the independent petroleum engineering firm, Netherland, Sewell & Associates, Inc., and related market factors to estimate the future cash flows for all proved developed (producing and non-producing) and proved undeveloped reserves. Property impairments occurred if a field discovered lower than anticipated reserves, reservoirs produced at a rate below original estimates or if commodity prices fell below a level that significantly affected anticipated future cash flows on the property. Proved oil and natural gas property values were reviewed when circumstances suggested the need for such a review and, if required, the proved properties were written down to their estimated fair market value based on proved reserves and other market factors. Unproved properties were reviewed quarterly to determine if there was impairment of the carrying value, with any such impairment charged to expense in the period. As a result of decreases in proved undeveloped reserves and proved developed non-producing reserves located in South Texas, in California and in the Gulf of Mexico, respectively, a non-cash impairment charge of approximately $202.1 million was recorded for the year ended December 31, 2004 in the combined statements of operations. The downward revisions of Calpine's estimates were based on the independent reservoir engineer's year-end reserve report, which reflected production results and drilling activity that occurred during 2004 and used historical field level and historical decline curves. Due to significant capital constraints by Calpine, drilling activity was minimized and correspondingly the estimate of proved reserves could not be supported through drilling success or future capital activity and the downward revision was required. In addition, under the successful efforts method of accounting for oil and natural gas properties, individual assets are grouped at the lowest level for which there are identifiable cash flows. With minimal drilling activity and the evaluation of cash flows at this level, proved reserves for South Texas and California fields and the Gulf of Mexico had to be revised downward at each individual field level. No impairment charge was recorded for the six months ended June 30, 2005.

Other property, plant and equipment primarily includes furniture, fixtures and automobiles, which are recorded at cost and depreciated on a straight-line basis over useful lives of five to seven years. Repair and maintenance costs are charged to expense as incurred while renewals and betterments are capitalized as additions to the related assets in the period incurred. Gains or losses from the disposal of property, plant and equipment are recorded in the period incurred. The net book value of the property, plant and equipment that is retired or sold is charged to accumulated depreciation, asset cost and amortization, and the difference is recognized as a gain or loss in the results of operations in the period the retirement or sale transpires.

*Capitalized Interest*

The Company capitalizes interest on capital invested in projects during the advanced stages of development and the drilling period in accordance with SFAS No. 34, "Capitalization of Interest Cost," ("SFAS No. 34") as amended by SFAS No. 58, "Capitalization of Interest Cost in Financial Statements That Include Investments Accounted for by the Equity Method (an Amendment of SFAS No. 34)." Upon commencement of production, capitalized interest, as a component of the total cost of a field is depleted. Financial Accounting Standards Board ("FASB") Interpretation No. 33 ("FIN 33") provides guidance for the application of SFAS 34 to the full cost method of accounting for oil and gas properties. Under FIN 33, costs of investments in unproved properties and major development projects, on which depreciation, depletion and amortization ("DD&A") expense is not currently taken and on which exploration or development activities are in progress, qualify for capitalization of interest. Capitalized interest is calculated by multiplying the weighted-average interest rate on debt by the amount of costs excluded. Capitalized interest cannot exceed gross interest expense.

*Fair Value of Financial Instruments*

The carrying value of cash and cash equivalents, accounts receivable, accounts payable, notes payable and other payables approximate their respective fair market values due to their short maturities. As of December 31, 2006, the carrying value of our debt was approximately $240 million. The fair value of our debt approximates the carrying value because the interest rates are based on floating rates identified by reference to market rates and because the interest rates charged are at rates at which we can currently borrow.

*Income Taxes*

Deferred income taxes are provided to reflect the tax consequences in future years of differences between the financial statement and tax basis of assets and liabilities using the liability method in accordance with the provisions set forth in SFAS No. 109, “Accounting for Income Taxes”. Income taxes are provided based on earnings reported for tax return purposes in addition to a provision for deferred income taxes and are measured using enacted tax rates and laws that will be in effect when the differences are expected to reverse. A valuation allowance is established to reduce deferred tax assets if it is more likely than not that the related tax benefits will not be realized.

*Concentrations of Credit Ris*k

Financial instruments, which potentially subject the Company to concentrations of credit risk, consist primarily of cash, accounts receivable and derivative instruments. The Company’s accounts receivable and derivative instruments are concentrated among entities engaged in the energy industry within the United States.

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*Executory Contracts*

Calpine had commodity contracts executed by them that did not qualify as leases under SFAS No. 13, “Accounting for Leases” or derivatives under SFAS No. 133, “Accounting for Derivative Instruments and Hedging Activities” as amended by SFAS 138 and SFAS 139 and interpreted by other related accounting literature. The contracts were classified as executory contracts, and as a result were accounted for on an accrual basis for the six months ended June 30, 2005 and the year ended December 31, 2004. The Company had no contracts classified as executory contracts for the six months ended December 31, 2005 or for the year ended December 31, 2006.

*Revenue Recognition*

The Company uses the sales method of accounting for the sale of its natural gas. When actual natural gas sales volumes exceed our delivered share of sales volumes, an over-produced imbalance occurs. To the extent an over-produced imbalance exceeds our share of the remaining estimated proved natural gas reserves for a given property, the Company records a liability. At December 31, 2006 and 2005, imbalances were insignificant.

Since there is a ready market for natural gas, crude oil and natural gas liquids (“NGLs”), the Company sells its products soon after production at various locations at which time title and risk of loss pass to the buyer. Revenue is recorded when title passes based on the Company’s net interest or nominated deliveries of production volumes. The Company records its share of revenues based on production volumes and contracted sales prices. The sales price for natural gas, crude oil and NGLs are adjusted for transportation cost and other related deductions. The transportation costs and other deductions are based on contractual or historical data and do not require significant judgment. Subsequently, these deductions and transportation costs are adjusted to reflect actual charges based on third party documents once received by the Company. Historically, these adjustments have been insignificant. In addition, natural gas and crude oil volumes sold are not significantly different from the Company’s share of production.

It is the Company’s policy to calculate and pay royalties on natural gas, crude oil and NGLs in accordance with the particular contractual provisions of the lease, license or concession agreements and the laws and regulations applicable to those agreements. Royalty liabilities are recorded in the period in which the natural gas, crude oil or NGLs are produced and are included in Royalties Payable on the Company’s Consolidated Balance Sheet.

*Derivative Instruments and Hedging Activities*

The Company uses derivative instruments to manage market risks resulting from fluctuations in commodity prices of natural gas and crude oil. The Company periodically enters into derivative contracts, including price swaps or costless price collars, which may require payments to (or receipts from) counterparties based on the differential between a fixed price and a variable price for a fixed quantity of natural gas or crude oil without the exchange of underlying volumes. The notional amounts of these financial instruments were based on expected proved production from existing wells at inception of the hedge instruments.

Derivatives are recorded on the balance sheet at fair market value and changes in the fair market value of derivatives are recorded each period in current earnings or other comprehensive income, depending on whether a derivative is designated and qualifies as a hedge transaction. The Company’s derivatives consist of cash flow hedge transactions in which the Company is hedging the variability of cash flows related to a forecasted transaction. Changes in the fair market value of these derivative instruments designated as cash flow hedges are reported in other comprehensive income and reclassified to earnings in the periods in which the contracts are settled. The ineffective portion of the cash flow hedge is recognized in current period earnings as other income (expense). Gains and losses on derivative instruments that do not qualify for hedge accounting are included in oil and natural gas revenue in the period in which they occur. The resulting cash flows from derivatives are reported as cash flows from operating activities.

At the inception of a derivative contract, the Company may designate the derivative as a cash flow hedge. For all derivatives designated as cash flow hedges, the Company formally documents the relationship between the derivative contract and the hedged items, as well as the risk management objective for entering into the derivative contract. To be designated as a cash flow hedge transaction, the relationship between the derivative and hedged items must be highly effective in achieving the offset of changes in cash flows attributable to the risk both at the inception of the derivative and on an ongoing basis. The Company measures hedge effectiveness on a quarterly basis and hedge accounting is discontinued prospectively if it is determined that the derivative is no longer effective in offsetting changes in the cash flows of the hedged item. Gains and losses included in accumulated other comprehensive income related to cash flow hedge derivatives that become ineffective remain unchanged until the related production is delivered. If the Company determines that it is probable that a hedged forecasted transaction will not occur, deferred gains or losses on the hedging instrument are recognized in earnings immediately. The Company does not enter into derivative agreements for trading or other speculative purposes. See Note 7 for a description of the derivative contracts which the Company executes.

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*Insurance Program.* CPN Insurance Corporation, a wholly owned captive insurance subsidiary of Calpine, charged Calpine premiums to insure worker's compensation, automobile liability, and general liability as well as all risk property insurance including business interruption. Accruals for casualty claims under the captive insurance program were recorded on a monthly basis, and were based upon the estimate of the total cost of the claims incurred during the policy period. Accruals for claims under the captive insurance program pertaining to property, including business interruption claims, were recorded on a claims-incurred basis. Claims were accrued on a gross basis before deductibles. The captive provided insurance coverage with limits up to $25 million per occurrence for property claims, including business interruption, and up to $500,000 per occurrence for casualty claims.

Subsequent to the Acquisition, the Company undertook to obtain insurance coverage from third party providers.

*Stock-Based Compensation*

On January 1, 2006, the Company adopted SFAS No. 123 (revised 2004), "Share-Based Payments" ("SFAS No. 123R"). This statement applies to all awards granted, modified, repurchased or cancelled after January 1, 2006 and to the unvested portion of all awards granted prior to that date. The Company adopted this statement using the modified version of the prospective application (modified prospective application). Under the modified prospective application, compensation cost for the portion of awards for which the employee's requisite service has not been rendered that are outstanding as of January 1, 2006 must be recognized as the requisite service is rendered on or after that date. The compensation cost for that portion of awards shall be based on the original fair market value of those awards on the date of grant as calculated for recognition under SFAS No. 123, "Accounting for Stock-Based Compensation" as amended by SFAS No. 148, "Accounting for Stock-Based Compensation - Transition and Disclosure" ("SFAS No. 123"). The compensation cost for these earlier awards shall be attributed to periods beginning on or after January 1, 2006 using the attribution method that was used under SFAS No. 123.

The adoption of the new standard did not have a significant impact on the Consolidated Balance Sheet because of the requirement to decrease retained earnings with an offsetting increase in additional paid-in capital. On the Consolidated/Combined Statement of Operations, the adoption of SFAS No. 123R resulted in decreases in both income before income taxes and net income of $5.7 million and $3.6 million, respectively, for the year ended December 31, 2006. The effect on net income per share for basic and diluted was a reduction $0.07 for the year ended December 31, 2006. See Note 12 of the notes to the Consolidated/Combined Financial Statements for additional disclosure.

Prior to the adoption of SFAS No. 123R, the Company presented all tax benefit deductions resulting from the exercise of stock options as operating cash flows in the accompanying Consolidated/Combined Statement of Cash Flows. SFAS No. 123R requires the cash flows that result from tax deductions in excess of the compensation expense recognized as an operating expense in 2006 and reported in pro forma disclosures prior to 2006 for those stock options (excess tax benefits) to be classified as financing cash flows.

Any excess tax benefit is recognized as a credit to additional paid in capital and is calculated as the amount by which the tax deduction we receive exceeds the deferred tax asset associated with the recorded stock compensation expense. We have approximately $0.2 million of related excess tax benefits which will be recognized upon utilization of our net operating loss carryforward.

*Treasury Stock*

Shares of common stock were repurchased by the Company as the shares were surrendered by the employees to pay tax withholding upon the vesting of restricted stock awards. These repurchases were not part of a publicly announced program to repurchase shares of the Company's common stock, nor does the Company have a publicly announced program to repurchase shares of common stock.

*Deferred Loan Fees*

Deferred loan fees incurred in connection with the credit facility are recorded on the Company's Consolidated Balance Sheet as deferred loan fees. The deferred loan fees are amortized to interest expense over a five year period using the straight-line method, which approximates the effective interest method.

*Future Development and Abandonment Costs*

Future development costs include costs incurred to obtain access to proved reserves such as drilling costs and the installation of production equipment. Future abandonment costs include costs to dismantle and relocate or dispose of our production platforms, gathering systems and related structures and restoration costs of land and seabed. We develop estimates of these costs for each of our properties based upon their geographic location, type of production structure, well depth, currently available procedures and ongoing consultations with construction and engineering consultants. Because these costs typically extend many years into the future, estimating these future costs is difficult and requires management to make judgments that are subject to future revisions based upon numerous factors, including changing technology and the political and regulatory environment. We review our assumptions and estimates of future development and future abandonment costs on an annual basis.

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We provide for future abandonment costs in accordance with SFAS No. 143, “Accounting for Asset Retirement Obligations”. This standard requires that a liability for the discounted fair value of an asset retirement obligation be recorded in the period in which it is incurred and the corresponding cost capitalized by increasing the carrying amount of the related long-lived asset. The liability is accreted to its present value each period, and the capitalized cost is depreciated over the useful life of the related asset.

***Recent Accounting Developments***

*The Fair Value Option for Financial Assets and Financial Liabilities.* In February 2007, the FASB issued SFAS No. 159, “The Fair Value Option For Financial Assets and Financial Liabilities - Including an Amendment of FASB Statement No. 115” (“SFAS No. 159), which permits an entity to choose to measure certain financial assets and liabilities at fair value. SFAS No. 159 also revises provisions of SFAS No. 115 that apply to available-for-sale and trading securities. This statement is effective for fiscal years beginning after November 15, 2007. The Company has not yet evaluated the potential impact of this standard.

*Fair Value Measurements*. In September 2006, the FASB issued SFAS No. 157,“Fair Value Measurements” (“SFAS No. 157”), which addresses how companies should measure fair value when companies are required to use a fair value measure for recognition or disclosure purposes under generally accepted accounting principles (“GAAP”). As a result of SFAS No. 157, there is now a common definition of fair value to be used throughout GAAP. SFAS No. 157 is effective for financial statements issued for fiscal years beginning after November 15, 2007, and interim periods within those years. The Company is still assessing the impact of this standard but does not expect the adoption of this standard to have a material impact on the Company’s consolidated financial position, results of operations, or cash flows.

*Guidance for Quantifying Financial Statement Misstatement.* In September 2006, the Securities and Exchange Commission (“SEC”) issued Staff Accounting Bulletin No. 108, “Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements” (“SAB 108”), which establishes an approach requiring the quantification of financial statement errors based on the effect of the error on each of the company’s financial statements and the related financial statement disclosures. This model is commonly referred to as a “dual approach” because it requires quantification of errors under both the “iron curtain” and “roll-over” methods. The roll-over method focuses primarily on the impact of a misstatement on the income statement, including the reversing effect of prior year misstatements; however, its use can lead to the accumulation of misstatements in the balance sheet. The iron curtain method focuses primarily on the effect of correcting the period end balance sheet with less emphasis on the reversing effects of prior year errors on the income statement. The Company used the iron curtain method for quantifying financial statement misstatements. The Company has applied the provisions of SAB 108 in connection with the preparation of the Company’s annual financial statements for the year ending December 31, 2006. The use of the dual approach did not have a material impact on the Company’s consolidated financial position, results of operations, or cash flows.

*Accounting for Uncertainty in Income Taxes.* In June 2006, the FASB issued FASB Interpretation No. 48, “Accounting for Uncertainty in Income Taxes - an interpretation of FASB Statement No. 109’(“FIN 48”). This interpretation provides guidance for recognizing and measuring uncertain tax positions, as defined in SFAS No. 109, “Accounting for Income Taxes.” FIN 48 prescribes a threshold condition that a tax position must meet for any of the benefit of the uncertain tax position to be recognized in the financial statements. Guidance is also provided regarding derecognition, classification and disclosure of these uncertain tax positions. FIN 48 is effective for fiscal years beginning after December 15, 2006. We are evaluating our tax positions and anticipate that the interpretation will not have a significant impact on the Company’s retained earnings at the time of adoption.

*Accounting for Certain Hybrid Financial Instruments*. In February 2006 , the FASB issued SFAS No. 155, "Accounting for Certain Hybrid Instruments - an amendment of FASB Statements 133 and 140", which is effective for all financial instruments acquired or issued after the beginning of an entity's first fiscal year that begins after September 15, 2006. The statement improves financial reporting by eliminating the exemption from applying SFAS No. 133 to interests in securitized financial assets so that similar instruments are accounted for similarly regardless of the form of the instruments. The statement also improves financial reporting by allowing a preparer to elect fair value measurement at acquisition, at issuance, or when a previously recognized financial instrument is subject to a re-measurement event, on an instrument-by-instrument basis, in cases in which a derivative would otherwise have to be bifurcated, if the holder elects to account for the whole instrument on a fair value basis. The adoption of this statement is not expected to have a material impact on the Company's consolidated financial position, results of operations, or cash flows.

**(4) Accounts Receivable**

Accounts receivable consisted of the following:

| | December 31, | | | |
|---|---|---|---|---|
| | 2006 | | 2005 | |
| | (In thousands) | | | |
| Natural gas, NGLs and oil revenue sales | $ | 34,027 | $ | 35,066 |
| Joint interest billings | | 959 | | 3,382 |
| Short-term receivable for royalty recoupment | | 1,422 | | 1,603 |
| Total | | 36,408 | | 40,051 |
| Less: allowance for doubtful accounts | | - | | - |
| Accounts receivable, net | $ | 36,408 | $ | 40,051 |

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**(5) Property, Plant and Equipment**

The Company's total property, plant and equipment consists of the following:

| | December 31, 2006 | December 31, 2005 |
|---|---|---|
| | (In thousands) | |
| Proved properties | $ 1,170,223 | $ 937,516 |
| Unproved properties | 35,178 | 21,217 |
| Gas gathering systems and compressor stations | 17,936 | 14,452 |
| Other | 4,562 | 2,912 |
| Total | 1,227,899 | 976,097 |
| Less: Accumulated depreciation, depletion, and amortization | (145,289) | (40,161) |
| | $ 1,082,610 | $ 935,936 |

Included in the Company's oil and natural gas properties are asset retirement obligations of $9.6 million and $9.1 million at December 31, 2006 and December 31, 2005, respectively, including additions of $0.5 million and $9.2 million for the year ended December 31, 2006 and the six months ended December 31, 2005, respectively.

At December 31, 2006 and 2005, the Company excluded the following capitalized costs from amounts subject to depreciation, depletion and amortization:

| | December 31, 2006 | December 31, 2005 |
|---|---|---|
| | (In thousands) | |
| Onshore: | | |
| Development cost | | |
| Incurred in 2006 | $ - | $ - |
| Incurred in 2005 | - | 1,716 |
| Exploration cost | | |
| Incurred in 2006 | 2,635 | - |
| Incurred in 2005 | - | 5,212 |
| Acquisition cost of undeveloped acreage | | |
| Incurred in 2006 | 9,976 | - |
| Incurred in 2005 | 16,978 | 19,684 |
| Capitalized interest | | |
| Incurred in 2006 | 1,925 | - |
| Incurred in 2005 | 228 | 555 |
| Total | 31,742 | 27,167 |
| | | |
| Offshore | | |
| | | |
| Exploration cost | | |
| Incurred in 2006 | $ - | $ - |
| Incurred in 2005 | - | 2,407 |
| Acquisition costs of undeveloped acreage | | |
| Incurred in 2006 | 5,860 | |
| Incurred in 2005 | - | 950 |

| | | |
|---|---|---|
| Capitalized interest | | |
| Incurred in 2006 | 184 | - |
| Incurred in 2005 | 27 | 28 |
| Total | 6,071 | 3,385 |
| | | |
| Total costs excluded from depreciation, depletion and amortization | 37,813 | 30,552 |

It is anticipated that the acquisition of undeveloped acreage and associated capitalized interest of $35.2 million and exploration costs of $2.6 million will be included in capitalized costs subject to depreciation, depletion and amortization within five years and one year, respectively.

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*Property Acquisitions.* During the fourth quarter of 2006, the Company acquired a 50% working interest in Main Pass 29 in the Gulf of Mexico from Andex/Wolf for $16.7 million and a 25% working interest in Grand Isle 72 in the Gulf of Mexico from Contango Oil and Gas for $7.0 million.

In April 2006, the Company also acquired certain oil and gas producing non-operated properties located in Duval, Zapata, and Jim Hogg Counties, Texas and Escambia County in Alabama from Contango Oil and Gas for $11.6 million in cash.

*Gas Gathering Systems and compressor stations.* The gas gathering systems and compressor stations of $17.9 million and $14.5 million for December 31, 2006 and 2005, respectively, are located in California, the Rocky Mountains and South Texas. The accumulated depreciation for the gas gathering systems at December 31, 2006 and 2005 was $1.5 million and $0.5 million, respectively. The depreciation expense associated with the gas gathering systems and compressor stations for the year ended December 31, 2006 (Successor), six months ended December 31, 2005 (Successor), the six months ended June 30, 2005 (Predecessor) and for the year ended December 31, 2004 (Predecessor) was $1.0 million, $0.5 million, $0.6 million and $1.5 million, respectively.

*Other Property and Equipment*. Other property and equipment at December 31, 2006 and 2005 of $4.6 million and $2.9 million, respectively, consists primarily of furniture and fixtures. The accumulated depreciation associated with other assets at December 31, 2006 and 2005 was $0.6 million and $0.1 million, respectively. For the year ended December 31, 2006 (Successor), the six months ended December 31, 2005 (Successor), six months ended June 30, 2005 (Predecessor) and year ended December 31, 2004 (Predecessor), depreciation expense for these assets was $0.5 million, $0.1 million, $0.4 million and $0.8 million, respectively.

## (6) Deferred Loan Fees

At December 31, 2006 and 2005, deferred loan fees were $3.4 million and $4.6 million, respectively. Total amortization expense for deferred loan fees was $1.2 million for the year ended December 31, 2006 and $0.6 million for the six months ended December 31, 2005.

## (7) Commodity Hedging Contracts and Other Derivatives

The Company has entered into financial fixed price swaps with prices ranging from $6.81 per MMBtu to $8.39 per MMBtu covering a portion of the Company's 2007, 2008 and 2009 production. The following financial fixed price swap transactions were outstanding with associated notional volumes and average underlying prices that represent hedged prices of commodities at various market locations at December 31, 2006:

| Settlement Period | Derivative Instrument | Hedge Strategy | Notional Daily Volume MMBtu | Total of Notional Volume MMBtu | Average Underlying Prices MMBtu | Total of Proved Natural Gas Production Hedged (1) | Fair Market Value Gain/(Loss) (In thousands) |
|---|---|---|---|---|---|---|---|
| 2007 | Swap | Cash flow | 49,341 | 18,009,500 | $ 7.76 | 40% | $ 17,216 |
| 2008 | Swap | Cash flow | 49,909 | 18,266,616 | 7.62 | 44% | (4,440) |
| 2009 | Swap | Cash flow | 26,141 | 9,541,465 | 6.99 | 26% | (5,962) |
| | | | | 45,817,581 | | | $ 6,814 |

(1) Estimated based on net gas reserves presented in the December 31, 2006 Netherland, Sewell, & Associates, Inc. reserve report.

The Company has also entered into costless collar transactions with an average floor price of $7.19 per MMBtu and an average ceiling price of $10.03 per MMBtu covering a portion of the Company’s 2007 production. If the floating price each month at the settlement point is greater than the ceiling price, the Company pays the counterparty an amount equal to the positive difference between the floating price and the ceiling price multiplied by the notional volume for the contract month. If the floating price for each month is less than the floor price, the counterparty pays the Company an amount equal to the positive difference between the floating price and the floor price multiplied by the notional volume for the contract month. The following costless collar transactions were outstanding with associated notional volumes and contracted ceiling and floor prices that represent hedge prices at various market locations at December 31, 2006:

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| Settlement Period | Derivative Instrument | Hedge Strategy | Notional Daily Volume MMBtu | Total of Notional Volume MMBtu | Average Floor Price MMBtu | Average Ceiling Price MMBtu | Fair Market Value Gain/(Loss) (In thousands) |
|---|---|---|---|---|---|---|---|
| 2007 | Costless Collar | Cash flow | 10,000 | 3,650,000 | $ 7.19 | $ 10.03 | $ 3,322 |
| | | | | 3,650,000 | | | $ 3,322 |

The total of proved natural gas production hedged in 2007 for the costless collars is approximately 8% based on the December 31, 2006 reserve report prepared by Netherland, Sewell, & Associates, Inc.

The Company's current cash flow hedge positions are with counterparties who are also lenders in the Company's credit facilities. This eliminates the need for independent collateral postings with respect to any margin obligation resulting from a negative change in fair market value of the derivative contracts in connection with the Company's hedge related credit obligations. As of December 31, 2006, the Company made no deposits for collateral.

The following table sets forth the results of third party hedge transactions for the respective period for the Consolidated Statement of Operations:

| | For the Year Ended December 31, 2006 | For the Six Months Ended December 31, 2005 |
|---|---|---|
| Natural Gas | | |
| Quantity settled (MMBtu) | 20,075,000 | 7,956,000 |
| Increase (Decrease) in natural gas sales revenue (In thousands) | $ 29,578 | $ (16,576) |

The Company expects to reclassify gains of $12.8 million based on market pricing as of December 31, 2006 to earnings from the balance in accumulated other comprehensive income (loss) on the Consolidated Balance Sheet during the next twelve months.

At December 2006, the Company had derivative assets of $21.2 million, of which $0.6 million is included in other assets on the Consolidated Balance Sheet. The Company also had derivative liabilities of $11.0 million on the Consolidated Balance Sheet at December 31, 2006. The derivative assets and liabilities relate to commodity hedges that represent the difference between hedged prices and market prices on hedged volumes of the commodities as of December 31, 2006. Hedging activities related to cash settlements on commodities increased revenues by $29.6 million for the year ended December 31, 2006 and decreased revenue by $16.6 million for the six months ended December 31, 2005.

Gains and losses related to ineffectiveness and derivative instruments not designated as hedging instruments are included in other income (expense) and were immaterial for the year ended December 31, 2006. There was no ineffectiveness related to cash-flow hedges recorded for the six months ended December 31, 2005. There were no gains or losses related to derivative instruments not designated as hedged instruments for the six months ended June 30, 2005 (Predecessor) or for the year ended December 31, 2004 (Predecessor) as no derivative instruments existed.

**(8) Accrued Liabilities**

The Company's accrued liabilities consists of the following:

| | December 31, 2006 | December 31, 2005 |
|---|---|---|
| | (In thousands) | |
| Accrued capital costs | $ 21,674 | $ 17,607 |
| Accrued Calpine settlement (see Note 2) | 11,400 | - |
| Accrued lease operating expense | 5,252 | 3,202 |
| Accrued payroll and employee incentive expense | 3,028 | 1,739 |
| Other | 1,745 | 5,849 |
| Total | $ 43,099 | $ 28,397 |

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**(9) Asset Retirement Obligation**

Activity related to the Company's asset retirement obligation ("ARO") is as follows:

| | For the Year Ended December 31, 2006 | Six Months Ended December 31, 2005 |
|---|---|---|
| | (In thousands) | |
| ARO as of the beginning of the period | $ 9,467 | $ 8,789 |
| Liabilities incurred during period | 467 | 447 |
| Liabilities settled during period | (33) | (121) |
| Accretion expense | 788 | 352 |
| ARO as of the end of the period | $ 10,689 | $ 9,467 |

Of the total ARO, approximately $0.4 million is classified as a current liability at December 31, 2006 and 2005, respectively. For the year ended December 31, 2006 and six months ended December 31, 2005, the Company recognized depreciation expense related to its ARO of approximately $1.1 million and $0.4 million, respectively.

**(10) Long-Term Debt**

Long-term debt consists of the following:

| | December 31, 2006 | December 31, 2005 |
|---|---|---|
| | (In thousands) | |
| Senior secured revolving line of credit | $ 165,000 | $ 165,000 |
| Second lien term loan | 75,000 | 75,000 |
| | 240,000 | 240,000 |
| Less: current portion of long-term debt | - | - |
| | $ 240,000 | $ 240,000 |

*Senior Secured Revolving Line of Credit.* BNP Paribas, in July 2005, provided the Company with a senior secured revolving line of credit concurrent with the Acquisition in the amount of up to $400.0 million ("Revolver"). This Revolver was syndicated to a group of lenders on September 27, 2005. Availability under the Revolver is restricted to the borrowing base, which initially was $275.0 million and was reset to $325.0 million, upon amendment, as a result of the hedges put in place in July 2005 and the favorable effects of the exercise of the over-allotment option the Company granted in the Company's private equity offering in July 2005 through which the Company received $70.0 million of funds (net of transaction fees). In July 2005, the Company repaid $60.0 million of the $225.0 million in original borrowings on the Revolver. The borrowing base is subject to review and adjustment on a semi-annual basis and other interim adjustments, including adjustments based on the Company's hedging arrangements. Amounts outstanding under the Revolver bear interest, as amended, at specified margins over the London Interbank Offered Rate ("LIBOR") of 1.25% to 2.00% (6.85% at December 31, 2006). Such margins will fluctuate based on the utilization of the facility. Borrowings under the Revolver are collateralized by perfected first priority liens and security interests on substantially all of the Company's assets, including a mortgage lien on oil and natural gas properties having at least 80% of the SEC PV-10 pretax reserve value, a guaranty by all of the Company's domestic subsidiaries, a pledge of 100% of the stock of domestic subsidiaries and a lien on cash securing the Calpine gas purchase and sale contract. These collateralized amounts under the mortgages are subject to semi-annual reviews based on updated reserve information. The Company is subject to the financial covenants of a minimum current ratio of not less than 1.0 to 1.0

as of the end of each fiscal quarter and a maximum leverage ratio of not greater than 3.5 to 1.0, calculated at the end of each fiscal quarter for the four fiscal quarters then ended, measured quarterly with the pro forma effect of acquisitions and divestitures. In addition, the Company is subject to covenants limiting dividends and other restricted payments, transactions with affiliates, incurrence of debt, changes of control, asset sales, and liens on properties. The Company was in compliance with all covenants at December 31, 2006. All amounts drawn under the Revolver are due and payable on July 7, 2009. Availability under the revolving line of credit was $159.0 million at December 31, 2006.

*Second Lien Term Loan.* BNP Paribas, in July 2005, also provided the Company with a second lien term loan concurrent with the acquisition, in the amount of $100.0 million ("Term Loan"). On September 27, 2005, the Company repaid $25.0 million of borrowings on the Term Loan, reducing the balance to $75.0 million and syndicated the Term Loan to a group of lenders including BNP Paribas. Borrowings under the Term Loan initially bore interest at LIBOR plus 5.00%. As a result of the hedges put in place in July 2005 and the favorable effects of the Company's private equity placement, as described above, the interest rate for the Term Loan has been reduced to LIBOR plus 4.00% (9.35% at December 31, 2006). The loan is collateralized by second priority liens on substantially all of the Company's assets. The Company is subject to the financial covenants of a minimum asset coverage ratio of not less than 1.5 to 1.0 and a maximum leverage ratio of not more than 4.0 to 1.0, calculated at the end of each fiscal quarter for the four fiscal quarters then ended, measured quarterly with the pro forma effect of acquisitions and divestitures. In addition, the Company is subject to covenants limiting dividends and other restricted payments, transactions with affiliates, incurrence of debt, changes of control, asset sales, and liens on properties. The Company was in compliance with all covenants at December 31, 2006. The principal balance of the Term Loan is due and payable on July 7, 2010.

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Aggregate maturities required on long-term debt at December 31, 2006 due in future years are as follows (In thousands):

| | |
|---|---|
| 2007 | $ - |
| 2008 | - |
| 2009 | 165,000 |
| 2010 | 75,000 |
| 2011 | - |
| Thereafter | - |
| Total | $ 240,000 |

**(11) Commitment and Contingencies**

The Company is party to various oil and natural gas litigation matters arising out of the normal course of business. The ultimate outcome of each of these matters cannot be absolutely determined, and the liability the Company may ultimately incur with respect to any one of these matters in the event of a negative outcome may be in excess of amounts currently accrued for with respect to such matters. Management does not believe any such matters will have a material adverse effect on the Company's financial position, results of operations or cash flows.

***Calpine Bankruptcy***

Calpine Corporation and certain of its subsidiaries filed for protection under the federal bankruptcy laws in the United States Bankruptcy Court of the Southern District of New York (the "Bankruptcy Court") on December 20, 2005. Calpine Energy Services, L.P., which filed for bankruptcy, has continued to make the required deposits into the Company's margin account and to timely pay for natural gas production it purchases from the Company's subsidiaries under various natural gas supply agreements. As part of the Acquisition, Calpine and the Company entered into a Transition Services Agreement, pursuant to which both parties were to provide certain services for the other for various periods of time. Calpine's obligation to provide services under the Transition Services Agreement ceased on July 6, 2006 and certain of Calpine's services ceased prior to the conclusion of the contract, which in neither case had any material effect on the Company. Additionally, Calpine Producer Services, L.P., which filed for bankruptcy, generally is performing its obligations under the Marketing and Services Agreement with the Company.

There remains the possibility, however, that there will be issues between the Company and Calpine that could amount to material contingencies in relation to the Purchase and Sale Agreement and interrelated agreements concurrently executed therewith, dated July 7, 2005, by and among Calpine, the Company, and various other signatories thereto (collectively, the "Purchase Agreement"), including unasserted claims and assessments with respect to (i) the still pending Purchase Agreement and the amounts that will be payable in connection therewith, (ii) whether or not Calpine and its affiliated debtors will, in fact, perform their remaining obligations in connection with the Purchase Agreement; and (iii) the ultimate disposition of the remaining Non-Consent Properties (and related royalty revenues). Calpine has specific obligations to the Company under the Purchase Agreement relating to these matters, and also has "further assurances" duties to the Company under the Purchase Agreement.

In addition, as to certain of the other oil and natural gas properties the Company purchased from Calpine in the Acquisition and for which payment was made on July 7, 2005, the Company will seek additional documentation from Calpine to eliminate any open issues in the Company's title or resolve any issues as to the clarity of the Company's ownership. Requests for additional documentation are customary in connection with transactions similar to the Acquisition. In the Acquisition, certain of these properties require ministerial governmental action approving the Company as qualified assignee and operator, which is typically required even though in most cases Calpine has already conveyed the properties to the Company free and clear of mortgages and liens by Calpine's creditors. As to certain other properties, the documentation delivered by Calpine at closing under the Purchase Agreement was incomplete. The Company remains hopeful that Calpine will work cooperatively with the Company to secure these ministerial governmental approvals and to accomplish the curative corrections for all of these properties. In addition, as to all properties acquired by the Company in the Acquisition, Calpine contractually agreed to provide the Company with such further assurances as the Company may reasonably request. Nevertheless, as a result of Calpine's bankruptcy filing, it remains uncertain as to whether Calpine will respond cooperatively. If Calpine does not fulfill its contractual obligations and does not complete the documentation necessary to resolve these issues, the Company will pursue all available remedies, including but not limited to a declaratory judgment to enforce the Company's rights and actions to quiet title. After pursuing these matters, if the Company experiences a loss of ownership with respect to these properties without receiving adequate consideration for any resulting loss to the Company, an outcome the Company's management considers to be remote, then the Company could experience losses which could have a material adverse effect on the Company's financial condition, statement of operations and cash flows.

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On June 29, 2006, Calpine filed a motion in connection with its pending bankruptcy proceeding in the Bankruptcy Court seeking the entry of an order authorizing Calpine to assume certain oil and natural gas leases that Calpine had previously sold or agreed to sell to the Company in the Acquisition, to the extent those leases constitute "unexpired leases of non-residential real property" and were not fully transferred to the Company at the time of Calpine's filing for bankruptcy. According to this motion, Calpine filed in order to avoid the automatic forfeiture of any interest it may have in these leases by operation of a statutory deadline. Calpine's motion did not request that the Bankruptcy Court determine whether these properties belong to the Company or Calpine, but the Company understands it was meant to allow Calpine to preserve and avoid forfeiture under the Bankruptcy Code of whatever interest Calpine may possess, if any, in these oil and natural gas leases. The Company disputes Calpine's contention that it may have an interest in any significant portion of these oil and natural gas leases and intends to take the necessary steps to protect all of the Company's rights and interest in and to the leases. On July 7, 2006, the Company filed an objection in response to Calpine's motion, wherein the Company asserted that oil and natural gas leases constitute interests in real property that are not subject to "assumption" under the Bankruptcy Code. In the objection the Company also requested that (a) the Bankruptcy Court eliminate from the order certain Federal offshore leases from the Calpine motion because these properties were fully conveyed to the Company in July 2005, and the Minerals Management Service has subsequently recognized the Company as owner and operator of all but three of these properties, and (b) any order entered by the Bankruptcy Court be without prejudice to, and fully preserve the Company's rights, claims and legal arguments regarding the characterization and ultimate disposition of the remaining described oil and natural gas properties. In the Company's objection, the Company also urged the Bankruptcy Court to require the parties to promptly address and resolve any remaining issues under the pre-bankruptcy definitive agreements with Calpine and proposed to the Bankruptcy Court that the parties seek arbitration (or at least mediation) to complete the following:

- Calpine's conveyance of the Non-Consent Properties to the Company;

- Calpine's execution of all documents and performance of all tasks required under "further assurances" provisions of the Purchase Agreement with respect to certain of the oil and natural gas properties for which the Company has already paid Calpine; and

- Resolution of the final amounts the Company is to pay Calpine, which the Company has concluded is approximately $79 million, consisting of roughly $68 million for the Non-Consent Properties and approximately $11 million in other true-up payment obligations.

At a hearing held on July 12, 2006, the Bankruptcy Court took the following steps:

- In response to an objection filed by the Department of Justice and asserted by the California State Lands Commission that the Debtors' Motion to Assume Non-Residential Leases and Set Cure Amounts (the "Motion"), did not allow adequate time for an appropriate response, Calpine withdrew from the list of Oil and Gas Leases that were the subject of the Motion those leases issued by the United States (and managed by the Minerals Management Service of the United States Department of Interior) (the "MMS Oil and Gas Leases") and the State of California (and managed by the California State Lands Commission) (the "CSLC Leases"). Calpine and both the Department of Justice and the State of California agreed to an extension of the existing deadline to November 15, 2006 to assume or reject the MMS Oil and Gas Leases and CSLC Leases under Section 365 of the Bankruptcy Code, to the extent the MMS Oil and Gas Leases and CSLC Leases are leases subject to Section 365. The effect of these actions was to render the objection of the Company inapplicable at that time; and

- The Bankruptcy Court also encouraged Calpine and the Company to arrive at a business solution to all remaining issues including approximately $68 million payable to Calpine for conveyance of the Non-Consent Properties.

On August 1, 2006, the Company filed a number of proofs of claim in the Calpine bankruptcy asserting claims against a variety of Calpine debtors seeking recovery of $27.9 million in liquidated amounts as well as unliquidated damages in amounts that can not presently be determined. The Company continues to work with Calpine on a cooperative and expedited basis toward resolution of unresolved conveyance of properties and post closing adjustments under the Purchase Agreement.

With respect to the stipulations between Calpine and MMS and Calpine and CSLC extending the deadline to assume or reject the MMS Oil and Gas Leases, these parties have further extended this deadline time by stipulation. The deadline was first extended to January 31, 2007 and recently was further extended to April 15, 2007 with respect to the MMS Oil and Gas Leases and April 30, 2007 with respect to the CSLC Leases. The Bankruptcy Court entered Orders related to the MMS Oil and Gas Leases and CSLC Leases which included appropriate language that we negotiated with Calpine for our protection in this regard.

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Recently, Calpine sought and obtained an extension to June 20, 2007 from the Bankruptcy Court for the period in which only Calpine, exclusively, may file its plan of reorganization. While there is no assurance that Calpine will file a plan of reorganization by the exclusively deadline, or that such a plan will be approved by the creditors and the Bankruptcy Court, the Company remains optimistic that the issues involving conclusion of the remaining conveyances of the Non-Consent Properties and obtaining the further assurances from Calpine under the Purchase Agreement, including perhaps resolution of any and all claims, may occur during 2007.

Calpine recently requested Bankruptcy Court approval of a new credit facility which would require it to grant liens to these new lenders in all of its assets, including any interest it may still hold in any oil and gas properties it obligated itself to convey to the Company under the Purchase Agreement. The Bankruptcy Court entered an Order approving Calpine's ability to obtain this new loan which includes appropriate language that the Company negotiated with Calpine for the Company's protection in this regard

However, there can be no assurance that Calpine, its creditors or other interest holders will not challenge the fairness of the Acquisition. For a number of reasons, including the Company's understanding of the process that Calpine followed in allowing market forces to set the purchase price for the Acquisition, the Company believes that it is unlikely that any challenges by the Calpine debtors or their creditors to the overall fairness of the Acquisition would be successful. The Company will take all necessary action to ensure the Company's rights under the Purchase agreement, the MMS Oil and Gas Leases, the CSLC Leases and the Bankruptcy Code are fully protected.

***Arbitration between Calpine Corp./RROLP and Pogo Producing Company***

On September 1, 2004, Calpine and Calpine Natural Gas L.P. sold their New Mexico oil and natural gas assets to Pogo Producing Company ("Pogo"). During the course of the sale, Pogo made three title defect claims on properties sold by Calpine (valued at approximately $2.7 million in the aggregate, subject to a $0.5 million deductible assuming no reconveyance) claiming, that certain leases subject to the sale had expired because of lack of production. Calpine had undertaken without success to resolve this matter by obtaining ratifications of a majority of the questionable leases. Calpine filed for bankruptcy protection before Pogo filed arbitration against it. Even though this is a retained liability of Calpine, Calpine declined to accept the Company's tender of defense and indemnity when Pogo filed for arbitration against the Company. The Company filed a motion to abate this arbitration which was denied by the arbitration panel and an adversary proceeding in the Calpine Bankruptcy Court requesting the Bankruptcy Court extend the automatic stay of the Bankruptcy Code to Pogo's arbitration claim. The Calpine debtors and creditors committee intervened in this adversary proceeding in support of the Company's request and also jointly opposed Pogo's motion to dismiss our adversary proceeding. The Bankruptcy Court denied Pogo's motion to dismiss the adversary proceeding. This is a retained liability by Calpine and it is too early for management to determine whether this matter will have any financial impact to the Company.

***Environmental***

Environmental expenditures are expensed or capitalized, as appropriate, depending on their future economic benefit. Expenditures that relate to an existing condition caused by past operations, and that do not have future economic benefit, are expensed. Liabilities related to future costs are recorded on an undiscounted basis when environmental assessments and/or remediation activities are probable and the cost can be reasonably estimated. The Company performed an environmental remediation study for two sites in California and correspondingly, recorded a liability, which at December 31, 2006 and 2005 was $0.1 million and $0.7 million, respectively. The Company does not expect that the outcome of our environmental matters discussed above will have a material adverse effect on the Company's financial position, results of operations or cash flows.

***Participation in a Regional Carbon Sequestration Partnership***

The Company has made preliminary preparations in connection with its participating in the United States Department of Energy's ("DOE") Regional Carbon Sequestration Partnership program ("WESTCARB") with the California Energy Commission and the University of California Lawrence Berkeley Laboratory. The Company has been selected by the DOE for this project. Under WESTCARB, the Company would be required to drill a carbon injection well, recondition an idle well for use as an observation well and provide WESTCARB with certain proprietary well data and technical assistance related to the evaluation and injection of carbon dioxide into a suitable natural gas reservoir in the Sacramento Basin. The Company's maximum contribution to WESTCARB is $1.0 million and will be limited to 20% of the total contributions to the project. The Company will not have any obligation under the WESTCARB project until it has entered into an acceptable contract and the project has obtained proper and necessary local, state and federal regulatory approvals, land use authorizations and third party property rights. No accrual was recorded at December 31, 2006 as the study is still in the preliminary stage.

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***Lease Obligations and Other Commitments***

The Company has operating leases for office space and other property and equipment. The Company incurred lease rental expense of $2.4 million and $ 0.6 million for the year ended December 31, 2006 and six months ended December 31, 2005. For the six months ended June 30, 2005 (predecessor) and for the year ended December 31, 2004 (predecessor) the expense for office lease and building maintenance was allocated by Calpine Corporation on a square footage basis coinciding with the move to Calpine Center in 2004. The expense allocated was $1.1 million and $1.6 million, respectively, for the six months ended June 30, 2005 (predecessor) and the year ended December 31, 2004 (predecessor).

Future minimum annual rental commitments under non-cancelable leases at December 31, 2006 are as follows (In thousands):

| | |
|---|---|
| 2007 | $ 2,421 |
| 2008 | 2,234 |
| 2009 | 1,965 |
| 2010 | 1,867 |
| 2011 | 1,915 |
| Thereafter | 3,978 |
| | $ 14,380 |

The Company has drilling rig commitments of $14.9 million for 2007.

**(12) Stock-Based Compensation**

On January 1, 2003, Calpine prospectively adopted the fair market value method of accounting for stock-based employee compensation pursuant to SFAS No. 123. Expense amounts included in the combined historical financial statements for the six months ended June 30, 2005 and for the year ended December 31, 2004 are based on stock-based compensation granted to employees by Calpine. Stock options were granted at an option price equal to the quoted market price at the date of the grant or award.

In determining the Company's accounting policies, the Company chose to apply the intrinsic value method pursuant to Accounting Principles Board Opinion No. 25, "Stock Issued to Employees" ("APB No. 25"), effective July 1, 2005. Under APB No. 25, no compensation expense is recognized when the exercise price for options granted equals the fair value of the Company's common stock on the date of the grant. Accordingly, the provisions of SFAS No. 123 permit the continued use of the method prescribed by APB No. 25 but require additional disclosures, including pro forma calculations of net income (loss) per share as if the fair value method of accounting prescribed by SFAS No. 123 had been applied.

Following is a summary of the Company's net income and net income per share for the six months ended December 31, 2005 as reported and on a pro forma basis as if the fair value method prescribed by SFAS No. 123 had been applied.

| | Successor Six Months Ended December 31, 2005 |
|---|---|

| | | (In thousands) |
|---|---|---|
| Net income, as reported | $ | 17,535 |
| Deduct: stock-based employee compensation expense determined under the fair value method for all awards, net of related tax effects | | (630) |
| Pro forma net income | $ | 16,905 |
| Net income per share: | | |
| Basic, as reported | $ | 0.35 |
| Basic, pro forma | $ | 0.34 |
| Diluted, as reported | $ | 0.35 |
| Diluted, pro forma | $ | 0.34 |

**Adoption of SFAS-123R**

Effective January 1, 2006, the Company began accounting for stock-based compensation under SFAS No. 123R, whereby the Company records stock-based compensation expense based on the fair value of awards described below. Stock-based compensation expense recorded for all share-based payment arrangements for the year ended December 31, 2006 was $5.7 million with an associated tax benefit of $2.1 million. Stock-based compensation expense for the six months ended December 31, 2005 was $4.2 million with an associated tax benefit of $1.6 million. For the six months ended June 30, 2005 (Predecessor) and year ended December 31, 2004 (Predecessor), stock-based compensation expense recorded was $0.2 million with a tax benefit of $0.1million and $0.1 million with a tax benefit of less than $0.1 million, respectively. The remaining compensation expense associated with total unvested awards as of December 31, 2006 was $9.3 million.

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**Successor**

**2005 Long-Term Incentive Plan**

In July 2005, the Board of Directors adopted the Rosetta 2005 Long-Term Incentive Plan whereby stock is granted to employees, officers and directors of the Company. The Plan allows for the grant of stock options, stock awards, restricted stock, restricted stock units, stock appreciation rights, performance awards and other incentive awards. Employees, non-employee directors and other service providers of the Company and its affiliates who, in the opinion of the Compensation Committee or another Committee of the Board of Directors (the "Committee"), are in a position to make a significant contribution to the success of the Company and the Company's affiliates are eligible to participate in the Plan. The Plan provides for administration by the Committee, which determines the type and size of award and sets the terms, conditions, restrictions and limitations applicable to the award within the confines of the Plan's terms. The maximum number of shares available for grant under the plan is 3,000,000 shares of common stock plus any shares of common stock that become available under the Plan for any reason other than exercise, such as shares traded for the related tax liabilities of employees. The maximum number of shares of common stock available for grant of awards under the Plan to any one participant is (i) 300,000 shares during any fiscal year in which the participant begins work for Rosetta and (ii) 200,000 shares during each fiscal year thereafter.

**Stock Options**

The Company has granted stock options under its 2005 Long-Term Incentive Plan. Options generally expire ten years from the date of grant. The exercise price of the options can not be less than the fair market value per share of the Company's common stock on the grant date. The options vest over a three year period.

The weighted average fair value at date of grant for options granted during the year ended December 31, 2006 and six months ended December 31, 2005 was $ 10.71 per share and $9.59 per share, respectively. The fair value of options granted is estimated on the date of grant using the Black-Scholes option-pricing model with the following assumptions:

| | **Successor** | |
|---|---|---|
| | **Year Ended December 31, 2006** | **Six Months Ended December 31, 2005** |
| Expected option term (years) | 6.5 | 6.5 |
| Expected volatility | 56.65% | 54.62% |
| Expected dividend rate | 0.00% | 0.00% |
| Risk free interest rate | 4.33% - 5.15% | 4.03% - 4.60% |

The Company has assumed an annual forfeiture rate of 5% for the awards granted in 2006 based on the Company's history for this type of award to various employee groups. Compensation expense is recognized ratably over the requisite service period and immediately for retirement-eligible employees.

The following table summarizes information related to outstanding and exercisable options held by the Company's employees at December 31, 2006:

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| | Shares | Weighted Average Exercise Price Per Share | Weighted Average Remaining Contractual Term (In years) | Aggregate Intrinsic Value (In thousands) |
|---|---|---|---|---|
| Outstanding at December 31, 2005 | 706,550 | $ 16.28 | | |
| Granted | 290,950 | 17.89 | | |
| Exercised | (49,896) | 16.09 | | |
| Forfeited | (94,250) | 16.64 | | |
| Outstanding at December 31, 2006 | 853,354 | $ 16.80 | 8.80 | $ 1,491 |
| | | | | |
| Options Vested and Exercisable at December 31, 2006 | 348,378 | $ 16.42 | 8.67 | $ 741 |

Stock-based compensation expense recorded for stock option awards for the year ended December 31, 2006 is $2.9 million. There was no stock-based compensation expense for stock option awards for the six months ended December 31, 2005. Unrecognized expense as of December 31, 2006 for all outstanding stock options is $5.0 million and will be recognized over a weighted average period of 1.29 years.

The total intrinsic value of options exercised during the year ended December 31, 2006 is $0.1 million. There were no options exercised for the six months ended December 31, 2005.

**Restricted Stock**

The Company has granted stock under its 2005 Long-Term Incentive Plan with a maximum contractual life of three years. The fair value of restricted stock grants is based on the value of the Company's common stock on the date of grant. Compensation expense is recognized ratably over the requisite service period. The Company also assumes an annual forfeiture rate of 5% for these awards based on the Company's history for this type of award to various employee groups.

The following table summarizes information concerning restricted stock held by the Company's employees at December 31, 2006:

| | Shares | Weighted Average Grant Date Fair Value |
|---|---|---|
| Non-vested shares outstanding at December 31, 2005 | 581,900 | $ 16.27 |
| Granted | 155,523 | 17.76 |
| Vested | (352,398) | 16.16 |
| Forfeited | (58,125) | 16.54 |
| Non-vested shares outstanding at December 31, 2006 | 326,900 | $ 17.05 |

The non-vested restricted stock outstanding at December 31, 2006 vests at a rate of 25% on the first anniversary of the date of grant, 25% on the second anniversary and 50% on the third anniversary. The restrictions on 270,000 shares lapsed on the day after the Company's effective date of its recently completed initial public offering in February 2006 and therefore vested in the first quarter of 2006. The fair value of awards vested for the year ended December 31, 2006 was $6.5 million.

Stock-based compensation expense recorded for restricted stock awards for the year ended December 31, 2006 and the six months ended December 31, 2005 was $2.8 million and $4.2 million, respectively. Unrecognized expense as of December 31, 2006 for all outstanding restricted stock awards is $4.3 million and will be recognized over a weighted average period of 1.42 years.

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**Predecessor**

***Retirement Savings Plan***

The Predecessor had a defined contribution savings plan, under Section 401(a) and 501(a) of the Internal Revenue Code, in which the Predecessor's employees were eligible to participate. The plan provided for tax deferred salary deductions and after-tax employee contributions. Employees were immediately eligible upon hire. Contributions included employee salary deferral contributions and employer profit-sharing contributions made entirely in cash of 4% of employees' salaries, with employer contributions capped at $8,400 per year for 2005. There were no employer profit-sharing contributions for the six months ended June 30, 2005. Employer profit-sharing contributions in 2004 totaled $0.4 million.

***2000 Employee Stock Purchase Plan***

The Predecessor adopted the 2000 Employee Stock Purchase Plan ("ESPP") in May 2000. The Predecessor's eligible employees could, in the aggregate, purchase up to 28,000,000 shares of common stock at semi-annual intervals through periodic payroll deductions. Purchases were limited to either a maximum value of $25,000 per calendar year based on the IRS Code Section 423 limitation or limited to 2,400 shares per purchase interval. Shares were purchased on May 31 and November 30 of each year until termination of the plan on May 31, 2010. For the six months ended June 30, 2005 under the ESPP, 36,817 shares were issued to Calpine's employees at a weighted average fair market value of $2.53 per share. For the year ended December 31, 2004, there were 91,809 shares issued to Calpine's employees at a weighted average fair market value of $3.26 per share. The purchase price was 85% of the lower of (i) the fair market value of the common stock on the participant's entry date into the offering period, or (ii) the fair market value on the semi-annual purchase date. The purchase price discount was significant enough to cause the ESPP to be considered compensatory under SFAS No. 123. As a result, the ESPP was accounted for as stock-based compensation in accordance with SFAS No. 123 . For the six months ended June 30, 2005 and year ended December 31, 2004, compensation expense of $0.2 million and $0.1 million, respectively, was recorded under the ESPP.

***1996 Stock Incentive Plan***

The Predecessor adopted the 1996 Stock Incentive Plan ("SIP") in September 1996 in which certain of the Company's employees were eligible to participate. The SIP succeeded the Predecessor's previously adopted stock option program. Under the SIP, the option exercise price generally equaled the stock's fair market value on date of grant. The SIP options generally vested ratably over four years and expired after ten years. No options were exercised for the six months ended June 30, 2005 or for the year ended December 31, 2004. As of June 30, 2005, the amount of shares outstanding under the 1996 incentive plan were 754,284.

The range of fair values at the date of grant for Calpine options granted during the six months ended June 30, 2005 and for the year ended December 31, 2004 was $1.27 per share and $1.99 to $4.56 per share, respectively. The fair value of options granted is estimated on the date of grant using the Black-Scholes option-pricing model with the following assumptions:

| | Predecessor | |
|---|---|---|
| | Six Months Ended June 30, 2005 | Year Ended December 31, 2004 |
| Expected option term (years) | 2.5 | 3 - 9.5 |
| Expected volatility | 58.00% | % |

| | | |
|---|---|---|
| | | 77% - 98 |
| Expected dividend rate | 0.00% | 0.00% |
| Risk free interest rate | 3.62% | 2.57% - 4.02% |

**(13) Income Taxes**

Under SFAS No. 109, “Accounting for Income Taxes,” deferred tax assets and liabilities are determined based on differences between the financial reporting and tax basis of assets and liabilities, and are measured using enacted tax rates and laws that will be in effect when the differences are expected to reverse.

At December 31, 2006, the Company had a deferred tax asset related to net operating loss carryforwards of approximately $82.0 million. Approximately $5.0 million of the net operating loss carryforward will expire in 2025. The remaining amount expires in 2026. The federal and state net operating loss carryforwards available are subject to limitations on their annual usage. Realization of the deferred tax assets and net operating loss carryforwards is dependent, in part, on generating sufficient taxable income prior to expiration of the loss carryforwards. The amount of the deferred tax asset considered realizable, however, could be reduced in the near term if estimates of future taxable income during the carryforward period are reduced. There is no valuation allowance recorded on this deferred tax asset as the Company believes it is more likely than not that the asset will be utilized.

The Company’s income tax expense (benefit) from continuing operations consists of the following:

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| | Successor | | Predecessor | |
|---|---|---|---|---|
| | Year Ended December 31, 2006 | Six Months Ended December 31, 2005 | Six Months Ended June 30, 2005 | Year Ended December 31, 2004 |
| | (In thousands) | | | |
| **Current:** | | | | |
| Federal | $ - | $ - | $ 7,556 | $ 25,452 |
| State | 172 | - | 1,067 | 3,670 |
| | 172 | - | 8,623 | 29,122 |
| **Deferred:** | | | | |
| Federal | 24,132 | 10,139 | 2,519 | (68,078) |
| State | 3,340 | 1,398 | 354 | (9,569) |
| | 27,472 | 11,537 | 2,873 | (77,647) |
| Total income tax expense (benefit) | $ 27,644 | $ 11,537 | $ 11,496 | $ (48,525) |

The differences between income taxes computed using the statutory federal income tax rate and that shown in the statement of operations from continuing operations are summarized as follows:

| | Successor | | | | Predecessor | | | |
|---|---|---|---|---|---|---|---|---|
| | Year Ended December 31, 2006 | | Six Months Ended December 31, 2005 | | Six Months Ended June 30, 2005 | | Year Ended December 31, 2004 | |
| | (In thousands) | (%) | (In thousands) | (%) | (In thousands) | (%) | (In thousands) | (%) |
| US Statutory Rate | $ 25,288 | 35.0% | $ 10,175 | 35.0% | $ 10,562 | 35.0% | $ (44,576) | 35.0% |
| State income tax, net of federal benefit | 2,283 | 3.2% | 909 | 3.1% | 924 | 3.1% | (3,896) | 3.1% |
| Transaction costs not deductible | - | 0.0% | 466 | 1.6% | - | 0.0% | - | 0.0% |
| Permanent differences and other | 73 | 0.0% | (13) | 0.0% | 10 | 0.0% | (53) | 0.0% |
| Total tax expense (Benefit) | $ 27,644 | 38.2% | $ 11,537 | 39.7% | $ 11,496 | 38.1% | $ (48,525) | 38.1% |

The effective tax rate in all periods is the result of the earnings in various domestic tax jurisdictions that apply a broad range of income tax rates. The provision for income taxes differs from the tax computed at the federal statutory income tax rate due primarily to state taxes, tax credits and other permanent differences. Future effective tax rates could be adversely affected if earnings are lower than anticipated, if unfavorable changes in tax laws and regulations occur, or if the Company experiences future adverse determinations by taxing authorities.

The components of deferred taxes are as follows:

| | December 31, 2006 | December 31, 2005 |
|---|---|---|
| | (In thousands) | |
| **Deferred tax assets** | | |
| Accrued liabilities not currently deductible | $ 1,410 | $ 1,614 |
| Other reserves not currently deductible | 413 | 276 |
| Hedge activity | - | 31,093 |
| Net operating loss carryforward | 30,428 | 608 |
| **Total deferred tax assets** | 32,251 | 33,591 |
| Oil and gas basis differences | (71,142) | (14,007) |
| Depreciation | (120) | (28) |
| Hedge activity | (3,821) | - |
| **Total gross deferred tax liabilities** | (75,083) | (14,035) |
| **Net deferred tax assets (liabilities)** | $ (42,832) | $ 19,556 |

## (14) Earnings Per Share

Basic earnings per share (“EPS”) is computed by dividing income available to common stockholders by the weighted average number of shares outstanding for the period. Diluted EPS reflects the potential dilution that could occur if contracts to issue common stock and related stock options were exercised at the end of the period.

The following is a calculation of basic and diluted weighted average shares outstanding:

| | Successor | | Predecessor | |
|---|---|---|---|---|
| | Year Ended December 31, 2006 | Six Months Ended December 31, 2005 | Six Months Ended June 30, 2005 | Year Ended December 31, 2004 |
| | (In thousands) | | | |
| Basic weighted average number of shares outstanding | 50,237 | 50,003 | 50,000 | 50,000 |
| Dilution effect of stock option and awards at the end of the period | 171 | 186 | 160 | - |
| Diluted weighted average number of shares outstanding | 50,408 | 50,189 | 50,160 | 50,000 |
| Stock awards and shares excluded from diluted earnings per share due to anti-dilutive effect | 198 | - | - | 160 |

In July 2005, the Company was capitalized with fifty million shares of common stock, through a private placement of 45,312,500 shares of the Company’s common stock to qualified institutional buyers and non-U.S. persons in transactions exempt from registration under the Securities Act of 1933 and through an exempt transaction in connection with the Acquisition. Additionally, the Company sold 4,687,500 shares of the Company’s common stock in an exempt transaction on July 14, 2005 for proceeds of $70 million (net of transaction costs) which were used to repay

$60 million of debt under the Company's new revolving credit facility with the remaining amount used to fund unspecified operating costs and general and administrative costs of oil and natural gas operations. In accordance with SEC Staff Accounting Bulletin No. 98, this capitalization has been retroactively reflected for purposes of calculating earnings per share for all prior periods presented in the accompanying statements of operations.

**(15) Operating Segments**

The Company has one reportable segment, oil and natural gas exploration and production, as determined in accordance with SFAS No. 131, "Disclosure About Segments of an Enterprise and Related Information". See below for information by geographic location.

*Geographic Area Information*

The Company owns oil and natural gas interests in eight main geographic areas all within the United States or its territorial waters. Geographic revenue and property, plant and equipment information below are based on physical location of the assets at the end of each period.

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| | Successor | | Predecessor | |
|---|---|---|---|---|
| | Year Ended December 31, 2006 (1) | Six Months Ended December 31, 2005 (1) | Six Months Ended June 30, 2005 | Year Ended December 31, 2004 |
| **Oil and Natural Gas Revenue** | (In thousands) | | | |
| California | $ 76,408 | $ 48,138 | $ 43,385 | $ 108,320 |
| Lobo | 71,450 | 39,062 | 26,474 | 62,417 |
| Perdido | 29,538 | 14,675 | 12,380 | 21,200 |
| State Waters | 8,183 | 6,761 | 2,345 | 88 |
| Other Onshore | 25,878 | 9,364 | 7,662 | 13,734 |
| Gulf of Mexico | 26,734 | 9,921 | 10,542 | 40,195 |
| Rocky Mountains | 2,115 | 338 | 161 | 284 |
| Mid-Continent | 1,879 | 1,309 | 842 | 1,549 |
| Other | - | 112 | 40 | - |
| | $ 242,185 | $ 129,680 | $ 103,831 | $ 247,787 |

| | Successor December 31, | |
|---|---|---|
| | 2006 | 2005 |
| **Oil and Natural Gas Properties (2)** | (In thousands) | |
| California | $ 435,167 | $ 386,513 |
| Lobo | 426,348 | 368,276 |
| Perdido | 52,702 | 25,983 |
| State Waters | 26,922 | 12,067 |
| Other Onshore | 102,734 | 75,737 |
| Gulf of Mexico | 125,425 | 77,416 |
| Rocky Mountains | 44,455 | 21,224 |
| Mid-Continent | 9,584 | 5,969 |
| Other | 4,562 | 2,912 |
| | $ 1,227,899 | $ 976,097 |

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(1) Excludes the effects of hedging.

(2) Oil and natural gas properties at December 31, 2006 and 2005 are reported gross. Under the full cost method of accounting for oil and natural gas properties, depreciation, depletion and amortization is not allocated to properties.

*Major Customers*

For the year ended December 31, 2006, the Company had two major customers, which accounted for approximately 60% of the Company's consolidated annual revenue. Calpine Energy Services ("CES"), a Calpine affiliate, was one of the major customers. The Company's annual consolidated revenue from CES accounted for approximately 45% and 80% for the year ended December 31, 2006 and six months ended December 31, 2005, respectively, and is reflected in oil and natural gas sales. For the six months ended June 30, 2005 and the year ended December 31, 2004, CES also accounted for approximately 75% of Calpine's annual combined revenues, which is reflected as oil and natural gas sales to affiliates. See Note 17 for a discussion of the Company's activity with CES.

For the year ended December 31, 2006 and six months ended December 31, 2005, revenues from sales to CES were $99.1million and $75.0 million, respectively. There was no receivable from CES at December 31, 2006 or 2005. For the six months ended June 30, 2005 and the year ended December 31, 2004, revenues from sales to CES were $82.0 million and $190.2 million, respectively. Under the gas purchase and sale contract, CES is required to collateralize payments under the contract by daily margin payments into the Company's collateral account, which are then settled at the end of the month. At December 31, 2006 and 2005, the Company had $17.9 million and $14.5 million in the margin account for December sales to CES which is included in other current liabilities on the Consolidated Balance Sheet.

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*Marketing Services Agreement*

The Company entered into a marketing and services agreement (“MSA”) with Calpine Producer Services (“CPS”) in July 2005 for the period through June 30, 2007. The MSA covers all the Company’s current and future production during the term of the MSA. Additionally, CPS provides services related to the sale of the Company’s production including nominating, scheduling, balancing and other customary marketing services and assists the Company with volume reconciliation, well connections, credit review, training, severance and other similar taxes, royalty support documentation, contract administration, billing, collateral management and other administrative functions. All CPS activities are performed as agent and on the Company’s behalf, and under the Company’s control and direction. The fee payable by the Company under the MSA is based on net proceeds of all commodity sales multiplied by 0.75%. For the year ended December 31, 2006 and the six months ended December 31, 2005, the fee was approximately $2.3 million and $1.4 million, respectively. The Company can request a reduction in the fee if the Company’s volume increases to 130,000 MMBtu per day and 190,000 MMBtu per day to 0.625% and 0.50% respectively. The MSA provides that all contracts, agreements, collateral and funds related to the marketing and sales activity be contracted directly with the Company or the Company’s designee, and paid directly to the Company.

**(16) Discontinued Operations**

On September 1, 2004, Calpine completed the sale of its Rocky Mountain natural gas properties that were primarily concentrated in two geographic areas: the Colorado Piceance Basin and the New Mexico San Juan Basin. Together, these assets represented approximately 120 billion cubic feet equivalent (“Bcfe”) of proved natural gas reserves, producing approximately 16.3 million net cubic feet equivalent (“MMcfe”) per day of natural gas as of September 1, 2004. Under the terms of the agreement, Calpine received net cash proceeds of approximately $218.7 million, and recorded a pre-tax gain of approximately $103.7 million.

The tables below present significant components of the Company’s income from discontinued operations for the year ended December 31, 2004:

| | Predecessor Year Ended December 31, 2004 (In thousands) |
|---|---|
| Total Revenue | $ 23,081 |
| Gain (loss) on disposal before taxes | 103,707 |
| Operating income from discontinued operations before taxes | 7,823 |
| Income from discontinued operations before taxes | 111,530 |
| Income tax provision | (43,090) |
| Income from discontinued operations, net of tax | $ 68,440 |

At December 31, 2004, there were no assets of discontinued operations as the assets were sold in September 2004.

Calpine allocated interest to discontinued operations in accordance with EITF Issue No. 87-24, “Allocation of Interest to Discontinued Operations.” Calpine included interest expense on debt that was required to be repaid as a result of a disposal transaction in discontinued operations. Additionally, other interest expense that cannot be attributed to other operations of Calpine was allocated based on the ratio of net assets to be sold less debt that is required to be paid as a result of the disposal transaction to the sum of total net assets of Calpine plus combined debt of Calpine, excluding (a) debt of the discontinued operation that will be assumed by the buyer, (b) debt that is required to be paid as a result of the disposal transaction and (c) debt that can be directly attributed to other operations of Calpine.

**(17) Related Party Transactions**

*Successor*

During the year ended December 31, 2006 and six months ended December 31, 2005, the Company purchased accounting contract services from a firm in which a principal partner is related to an officer of the Company. Total expenditures for these services were $1.0 million and $0.6 million, respectively.

The Company provided LOTO Energy, LLC (“LOTO I”) certain services for a fee pursuant to an administrative services agreement that ended on June 30, 2006. LOTO I is indirectly owned in part by family trusts established by our director G. Louis Graziadio, III. Additionally, in January 2006, the Company purchased certain leases from LOTO Energy II, LLC (“LOTO II”) for cash, subject to a retained overriding royalty in favor of LOTO II. The Company also made certain ongoing development commitments to LOTO II associated with these leases. LOTO II is indirectly owned in part by family trusts established by Mr. Graziadio who was its president at the time of this purchase.

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*Predecessor*

Calpine and certain of Calpine's affiliates have entered into various agreements with respect to the domestic oil and natural gas properties. These contracts were all cancelled at the date of the Acquisition of the oil and natural gas business by the Company. Following is a general description of each of the various agreements:

*Agency Agreement.* Calpine entered into a service agreement with CPS beginning April 1, 2003. The contract automatically renewed every year unless terminated by either party. CPS provided services related to Calpine's production, including marketing, contract administration, royalty and working interest owner issues, and receipt of payments. All activities performed by CPS were performed on behalf of Calpine and under Calpine's control and direction, in exchange for a fee for services rendered. Calpine dispensed all royalty payments when CPS provided accurate and timely details. Management fees of $0.9 million and $1.9 million for the six months ended June 30, 2005 and year ended December 31, 2004, respectively, were recorded as Affiliated marketing fees in the Consolidated/Combined Statements of Operations.

*Natural Gas Sales.* Calpine and CES executed index based natural gas sales under master agreements. Many of these transactions were executed by CPS on behalf of Calpine; however, Calpine sold directly to CPS and CES prior to the agency agreement with CPS being executed. Oil and natural gas sales to affiliates were $81.9 million for the six months ended June 30, 2005 and $190.2 million a for the year ended December 31, 2004 .

Natural gas balancing activities between CES and Calpine, where Calpine bought back natural gas above the needs of CES and then re-sold that excess natural gas to third parties was recorded net to Affiliated marketing fees in the Consolidated/Combined Statements of Operations. The net effect of these balancing activities resulted in a gain or loss in the respective period. The net balancing cost (reduction of cost) for the year ended December 31, 2004 was $(0.1) million. There was no net balancing cost for the six months ended June 30, 2005.

*Notes Payable to Affiliates.* Prior to the acquisition in July 2005, the Company and Calpine had an agreement whereby Calpine loaned the Company funds for capital expenditures, as well as operating costs. The Company repaid the balance of the note to Calpine as excess cash was available from continuing operations and asset sales. Interest on the note was compounded monthly at an annual rate of 8.75% during 2002 and 2003 and for the period through July of 2004, when the rate became variable, raising from 9.0% in August 2004 to 9.05% in December 2004. Additionally, the Company received equipment transferred from CPN Pipeline Company ("Pipeline") during 2004 that was transferred at historical cost as the transaction was between entities under common control. The Company's payable to Pipeline was subsequently transferred to Calpine and increased the note discussed above. As part of certain credit facilities entered into by Calpine, the security included direct liens on the domestic oil and natural gas properties. The balance of Notes payable to Affiliates was $127.2 million at December 31, 2004. Notes payable of $92.9 million were retired at the time of the Acquisition.

*Other Services.* Calpine provided general services to other subsidiaries of Calpine that were recorded in other revenue on the Consolidated/Combined Statements of Operations, which were insignificant.

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## Supplemental Oil and Gas Disclosures

**(Unaudited)**

The following disclosures for the Company are made in accordance with Statement of Financial Accounting Standards ("SFAS") No. 69, "Disclosures About Oil and Natural gas Producing Activities (an amendment of FASB Statements 19, 25, 33 and 39)" ("SFAS No. 69"). Users of this information should be aware that the process of estimating quantities of proved, proved developed and proved undeveloped crude oil and natural gas reserves is very complex, requiring significant subjective decisions in the evaluation of all available geological, engineering and economic data for each reservoir. The data for a given reservoir may also change substantially over time as a result of numerous factors including, but not limited to, additional development activity, evolving production history and continual reassessment of the viability of production under varying economic conditions. Consequently, material revisions to existing reserve estimates occur from time to time. Although every reasonable effort is made to ensure that reserve estimates reported represent the most accurate assessments possible, the significance of the subjective decisions required and variances in available data for various reservoirs make these estimates generally less precise than other estimates presented in connection with financial statement disclosures.

Proved reserves represent estimated quantities of natural gas and crude oil that geological and engineering data demonstrate, with reasonable certainty, to be recoverable in future years from known reservoirs under economic and operating conditions existing at the time the estimates were made.

Proved developed reserves are proved reserves expected to be recovered, through wells and equipment in place and under operating methods being utilized at the time the estimates were made.

Proved undeveloped reserves are reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion. Reserves on undrilled acreage are limited to those drilling units offsetting productive units that are reasonably certain of production when drilled. Proved reserves for other undrilled units can be claimed only where it can be demonstrated with certainty that there is continuity of production from the existing productive formation. Estimates for proved undeveloped reserves are not attributed to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual tests in the area and in the same reservoir.

Estimates of proved developed and proved undeveloped reserves as of December 31, 2006, 2005 and 2004, were based on estimates made by our independent engineers, Netherland, Sewell & Associates, Inc. Netherland, Sewell & Associates, Inc., are engaged by and provide their reports to our senior management team. We make representations to the independent engineers that we have provided all relevant operating data and documents, and in turn, we review these reserve reports provided by the independent engineers to ensure completeness and accuracy. Our Chairman of the Board, President and Chief Executive Officer makes the final decision on booked proved reserves by incorporating the proved reserves from the independent engineers' reports.

Our relevant management controls over proved reserve attribution, estimation and evaluation include:

- Controls over and processes for the collection and processing of all pertinent operating data and documents needed by our independent reservoir engineers to estimate our proved reserves; and
- Engagement of well qualified and independent reservoir engineers for review of our operating data and documents and preparation of reserve reports annually in accordance with all SEC reserve estimation guidelines.

Market prices as of each year-end were used for future sales of natural gas, crude oil and natural gas liquids. Future operating costs, production and ad valorem taxes and capital costs were based on current costs as of each year-end, with no escalation. There are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting the future rates of production and timing of development expenditures. Reserve data represent estimates only and should not be construed as being exact. Moreover, the standardized measure should not be construed as the current market value of the proved oil and natural gas reserves or the costs that would be incurred to obtain equivalent reserves. A market value determination would include many additional factors including (a) anticipated future changes in natural gas and crude oil prices, production and development costs, (b) an allowance for return on investment, (c) the value of additional reserves, not considered proved at present, which may be recovered as a result of further exploration and development activities, and (d) other business risk.

In accordance with SFAS No. 144 "Accounting for Impairment or Disposal of Long-Lived Assets" ("SFAS No. 144"), United States natural gas reserves and petroleum asset divestments were accounted for as discontinued operations in preparing SFAS No. 69 data.

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**Capitalized Costs Relating to Oil and Gas Producing Activities**

The following table sets forth the capitalized costs relating to the Company's natural gas and crude oil producing activities at December 31, 2006 and 2005:

| | Successor | |
|---|---|---|
| | 2006 | 2005 |
| | (In thousands) | |
| Proved properties | $ 1,170,223 | $ 937,516 |
| Unproved properties | 35,178 | 21,217 |
| Total | 1,205,401 | 958,733 |
| Less: Accumulated depreciation, depletion, and amortization | (143,216) | (39,546) |
| Net capitalized costs | $ 1,062,185 | $ 919,187 |
| Company's share of equity method investees' net capitalized costs | $ 1,166 | $ 1,225 |

Pursuant to SFAS No. 143 "Accounting for Asset Retirement Obligations", net capitalized cost includes asset retirement cost of $9.6 million and $9.1 million as of December 31, 2006, and December 31, 2005, respectively.

**Costs Incurred in Oil and Natural Gas Property Acquisition, Exploration and Development Activities**

The following table sets forth costs incurred related to the Company's oil and natural gas activities for the year ended December 31, 2006 (Successor), six months ended December 31, 2005 (Successor), June 30, 2005 (Predecessor) and for the year ended December 31, 2004 (Predecessor):

| | Continued Operations | Discontinued Operations |
|---|---|---|
| | (In thousands) | |
| **Year Ended December 31, 2006 (Successor)** | | |
| Acquisition costs of properties | | |
| Proved | $ 39,194 | $ - |
| Unproved | 22,317 | - |
| Subtotal | 61,511 | - |
| Exploration costs | 48,446 | - |
| Development costs | 125,971 | - |
| Total | $ 235,928 | $ - |
| Company's share of equity method investees' costs of property acquisition, exploration and development | $ 61 | $ - |
| | | |
| **Six months ended December 31, 2005 (Successor)** | | |
| Acquisition costs of properties | | |
| Proved | $ 915,700 | $ - |
| Unproved | 21,930 | - |
| Subtotal | 937,630 | - |
| Exploration costs | 19,294 | - |
| Development costs | 35,915 | - |
| Total | $ 992,839 | $ - |
| | $ 181 | $ - |

Company's share of equity method investees' costs of property acquisition, exploration and development

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| | | Continued Operations | | Discontinued Operations |
|---|---|---|---|---|
| | | (In thousands) | | |
| **Six months ended June 30, 2005 (Predecessor)** | | | | |
| Acquisition costs of properties | | | | |
| Proved | $ | - | $ | - |
| Unproved | | 1,640 | | - |
| Subtotal | | 1,640 | | - |
| Exploration costs | | 13,110 | | - |
| Development costs | | 20,233 | | - |
| Total | $ | 34,983 | $ | - |
| Company's share of equity method investees' costs of property acquisition, exploration and development | $ | 25 | $ | - |
| | | | | |
| **Year Ended December 31, 2004 (Predecessor)** | | | | |
| Acquisition costs of properties | | | | |
| Proved | $ | 1,425 | $ | 558 |
| Unproved | | 3,060 | | 55 |
| Subtotal | | 4,485 | | 613 |
| Exploration costs | | 22,471 | | 214 |
| Development costs | | 42,038 | | 5,706 |
| Total | $ | 68,994 | $ | 6,533 |
| Company's share of equity method investees' costs of property acquisition, exploration and development | $ | 56 | $ | 2,020 |

**Results of operations for oil and natural gas producing activities**

| | Successor | | | | Predecessor | | | |
|---|---|---|---|---|---|---|---|---|
| | | Year Ended December 31, 2006 | | Six Months Ended December 31, 2005 | | Six Months Ended June 30, 2005 | | Year Ended December 31, 2004 |
| Oil and natural gas producing revenues | | | | | | | | |
| Third-party | $ | 271,751 | $ | 113,090 | $ | 21,803 | $ | 57,572 |
| Affiliate | | - | | - | | 81,952 | | 190,215 |
| Total Revenues | | 271,751 | | 113,090 | | 103,755 | | 247,787 |
| Exploration expenses, including dry hole | | | | - | | 4,317 | | 7,440 |
| Production costs | | 47,507 | | 22,314 | | 22,295 | | 40,503 |
| Depreciation, depletion, and amortization | | 105,886 | | 40,500 | | 30,679 | | 81,590 |
| Oil and natural gas impairment | | - | | - | | - | | 202,120 |
| Income (loss) before income taxes | | 118,358 | | 50,276 | | 46,464 | | (83,866) |
| Income tax provision (benefit) | | 44,621 | | 19,155 | | 17,656 | | (31,869) |
| Results of continuing operations | $ | 73,737 | $ | 31,121 | $ | 28,808 | $ | (51,997) |
| Results of discontinued operations | $ | - | $ | - | $ | - | $ | 7,162 |
| Company's share of equity method investees' results of operations for | $ | 227 | $ | 241 | $ | 161 | $ | 324 |

producing activities

The results of operations for oil and natural gas producing activities exclude interest charges and general and administrative expenses. Sales are based on market prices.

**Net Proved and Proved Developed Reserve Summary**

The following table sets forth the Company's net proved and proved developed reserves (all within the United States) at December 31, 2006, 2005 and 2004, and the changes in the net proved reserves for each of the three years in the period then ended as estimated by the independent petroleum consultants. During the year ended December 31, 2006 and six months ended December 31, 2005, other relates to reserves associated with Non-Consent Properties. See Note 2.

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During 2004, Calpine revised downward its estimate of continuing proved reserves by a total of approximately 58 Bcfe or 12%. Approximately 69% of the total revision was attributable to the downward revision of Calpine’s estimate of proved reserves in the South Texas fields due to information received from production results and drilling activity that occurred during 2004. The remaining 31% of the total revision was due to the downward revision of Calpine’s estimate of proved reserves in California of 17%, Other Onshore of 10% and Gulf of Mexico of 4%. As a result of the decreases in proved undeveloped reserves, Calpine recorded a non-cash impairment charge of approximately $202.1 million was recorded for the year ended December 31, 2004.

| | Continued Operations | Discontinued Operations |
|---|---|---|
| **Natural gas (Bcf)(1):** | | |
| Net proved reserves at January 1, 2004 (Predecessor) | 455 | 100 |
| Revisions of previous estimates | (60) | 14 |
| Purchases in place | 1 | - |
| Extensions, discoveries and other additions | 17 | 5 |
| Sales in place | (2) | (115) |
| Production | (37) | (4) |
| Net proved reserves at December 31, 2004 (Predecessor) | 374 | - |
| Revisions of previous estimates | (11) | - |
| Purchases in place | - | - |
| Extensions, discoveries and other additions | 28 | - |
| Production | (27) | - |
| Other (5) | (19) | - |
| Net proved reserves at December 31, 2005 (Successor) (6) | 345 | - |
| Revisions of previous estimates | (10) | - |
| Purchases in place | 4 | - |
| Extensions, discoveries and other additions | 81 | - |
| Sales in place | - | - |
| Production | (30) | - |
| Net proved reserves at December 31, 2006 (Successor) | 390 | - |
| Company's proportional interest in reserves of investees accounted for by the equity method - December 31, 2006 (Successor) | 5 | - |

| | Continued Operations | Discontinued Operations |
|---|---|---|
| **Natural gas liquids and crude oil (MBbl)(2)(3)** | | |
| Net proved reserves at January 1, 2004 (Predecessor) | 2,902 | 466 |
| Revisions of previous estimates | 260 | (15) |
| Purchases in place | 3 | - |
| Extensions, discoveries and other additions | 48 | 16 |
| Sales in place | (2) | (451) |
| Production | (600) | (16) |
| Net proved reserves at December 31, 2004 (Predecessor) | 2,611 | - |
| Revisions of previous estimates | 153 | - |
| Extensions, discoveries and other additions | 108 | - |
| Sales in place | (9) | - |
| Production | (360) | - |
| Other (5) | (22) | - |
| Net proved reserves at December 31, 2005 (Successor) (6) | 2,481 | - |
| Revisions of previous estimates | 424 | - |
| Purchases in place | 286 | - |
| Extensions, discoveries and other additions | 315 | - |
| Sales in place | - | - |
| Production | (576) | - |
| Net proved reserves at December 31, 2006 (Successor) | 2,930 | - |
| Company's proportional interest in reserves of investees accounted for by the equity method - December 31, 2006 (Successor) | - | - |

| | Continued Operations | Discontinued Operations |
|---|---|---|
| **Bcfe (1) equivalents (4)** | | |
| Net proved reserves at January 1, 2004 (Predecessor) | 472 | 103 |
| Revisions of previous estimates | (58) | 14 |
| Purchases in place | 1 | - |
| Extensions, discoveries and other additions | 17 | 5 |
| Sales in place | (2) | (118) |
| Production | (41) | (4) |
| Net proved reserves at December 31, 2004 (Predecessor) | 389 | - |
| Revisions of previous estimates | (10) | - |
| Extensions, discoveries and other additions | 29 | - |
| Production | (30) | - |
| Other (5) | (19) | - |
| Net proved reserves at December 31, 2005 (Successor) (6) | 359 | - |
| Revisions of previous estimates | (7) | - |
| Purchases in place | 6 | - |
| Extensions, discoveries and other additions | 83 | - |
| Sales in place | - | - |
| Production | (33) | - |
| Net proved reserves at December 31, 2006 (Successor) | 408 | - |
| Company's proportional interest in reserves of investees accounted for by the equity method - December 31, 2006 (Successor) | 5 | - |

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**Net proved developed reserves**

| | Proved Developed Reserves | | |
|---|---|---|---|
| | Natural gas (Bcf) (1) | Natural gas liquids and crude oil (MBbl) (2) (3) | Equivalents Bcfe (4) |
| December 31, 2004 (Predecessor) | 256 | 1,402 | 264 |
| December 31, 2005 (Successor) (6) | 223 | 1,320 | 231 |
| December 31, 2006 (Successor) (6) | 251 | 1,965 | 263 |

(1) Billion cubic feet or billion cubic feet equivalent, as applicable

(2) Thousand barrels

(3) Includes crude oil, condensate and natural gas liquids

(4) Natural gas liquids and crude oil volumes have been converted to equivalent natural gas volumes using a conversion factor of six cubic feet of natural gas to one barrel of natural gas liquids and crude oil.

(5) Reserves associated with Non-Consent Properties.

(6) Excludes reserves associated with Non-Consent Properties.

**Standardized Measure of Discounted Future Net cash Flows Relating to Proved Oil and Natural Gas Reserves**

The following information has been developed utilizing procedures prescribed by SFAS No. 69 and based on natural gas and crude oil reserve and production volumes estimated by the independent petroleum reservoir engineers. This information may be useful for certain comparison purposes but should not be solely relied upon in evaluating the Company or its performance. Further, information contained in the following table should not be considered as representative of realistic assessments of future cash flows, nor should the standardized measure of discounted future net cash flows be viewed as representative of the current value of the Company's oil and natural gas assets.

The future cash flows presented below are based on sales prices, cost rates and statutory income tax rates in existence as of the date of the projections. It is expected that material revisions to some estimates of natural gas and crude oil reserves may occur in the future, development and production of the reserves may occur in periods other than those assumed, and actual prices realized and costs incurred may vary significantly from those used. Income tax expense has been computed using expected future tax rates and giving effect to tax deductions and credits available, under current laws, and which relate to oil and natural gas producing activities.

Management does not rely upon the following information in making investment and operating decisions. Such decisions are based upon a wide range of factors, including estimates of probable as well as proved reserves and varying price and cost assumptions considered more representative of a range of possible economic conditions that may be anticipated.

The following table sets forth the standardized measure of discounted future net cash flows from projected production of the Company's natural gas and crude oil reserves for the years ended December 31, 2006, 2005 and 2004.

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| | Continued Operations | | Discontinued Operations | |
|---|---|---|---|---|
| | (In millions) | | | |
| **December 31, 2006 (Successor)** | | | | |
| Future cash inflows | $ | 2,452 | $ | - |
| Future production costs | | (684) | | - |
| Future development costs | | (312) | | - |
| Future net cash flows before income taxes | | 1,456 | | - |
| Future income taxes | | (182) | | - |
| Future net cash flows | | 1,274 | | - |
| Discount to present value at 10% annual rate | | (552) | | - |
| Standardized measure of discounted future net cash flows relating to proved natural gas, natural gas liquids and crude oil reserves | $ | 722 | $ | - |
| Company's share of equity method investee's standardized measure of discounted future net cash flows | | 2 | $ | - |

| | Continued Operations | | Discontinued Operations | |
|---|---|---|---|---|
| | (In millions) | | | |
| **December 31, 2005 (Successor)** | | | | |
| Future cash inflows | $ | 3,232 | $ | - |
| Future production costs | | (647) | | - |
| Future development costs | | (244) | | - |
| Future net cash flows before income taxes | | 2,341 | | - |
| Future income taxes | | (487) | | - |
| Future net cash flows | | 1,854 | | - |
| Discount to present value at 10% annual rate | | (738) | | - |
| Standardized measure of discounted future net cash flows relating to proved natural gas, natural gas liquids and crude oil reserves | $ | 1,116 | $ | - |
| Company's share of equity method investee's standardized measure of discounted future net cash flows | $ | 2 | $ | - |
| | | | | |
| **December 31, 2004 (Predecessor)** | | | | |
| Future cash inflows | $ | 2,427 | $ | - |
| Future production costs | | (568) | | - |
| Future development costs | | (190) | | - |
| Future net cash flows before income taxes | | 1,669 | | - |
| Future income taxes | | (474) | | - |
| Future net cash flows | | 1,195 | | - |
| Discount to present value at 10% annual rate | | (542) | | |
| Standardized measure of discounted future net cash flows relating to proved natural gas, natural gas liquids and crude oil reserves | $ | 653 | $ | - |
| Company's share of equity method investee's standardized measure of discounted future net cash flows | $ | 2 | $ | - |

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**Changes in Standardized Measure of Discounted Future Net cash Flows**

The following table sets forth the changes in the standardized measure of discounted future net cash flows at December 31, 2006, 2005 and 2004.

| | Continued Operations | Discontinued Operations |
|---|---|---|
| | (In millions) | |
| **Balance, January 1, 2004 (predecessor)** | $ 775 | $ 150 |
| Sales and transfers of natural gas, natural gas liquids and crude oil produced, net of production costs | (205) | (18) |
| Net changes in prices and production costs | 39 | 2 |
| Extensions, discoveries, additions and improved recovery, net of related costs | 60 | 11 |
| Development costs incurred | 25 | 5 |
| Revisions of previous quantity estimates and development costs | (193) | 10 |
| Accretion of discount | 78 | 15 |
| Net change in income taxes | 39 | 59 |
| Purchases of reserve in place | 2 | - |
| Sales of reserves in place | (5) | (208) |
| Changes in timing and other | 38 | (26) |
| **Balance December 31, 2004 (Predecessor)** | 653 | - |
| Sales and transfers of natural gas, natural gas liquids and crude oil produced, net of production costs | (184) | - |
| Net changes in prices and production costs | 526 | - |
| Extensions, discoveries, additions and improved recovery, net of related costs | 123 | - |
| Development costs incurred | 89 | - |
| Revisions of previous quantity estimates and development costs | (84) | - |
| Accretion of discount | 74 | - |
| Net change in income taxes | (55) | |
| Changes in timing and other | (26) | |
| **Balance December 31, 2005 (Successor) (1)** | 1,116 | - |
| Sales and transfers of natural gas, natural gas liquids and crude oil produced, net of production costs | (224) | - |
| Net changes in prices and production costs | (547) | - |
| Extensions, discoveries, additions and improved recovery, net of related costs | 275 | - |
| Development costs incurred | 73 | - |
| Revisions of previous quantity estimates and development costs | (348) | - |
| Accretion of discount | 132 | - |
| Net change in income taxes | 132 | - |
| Purchases of reserve in place | 19 | - |
| Sales of reserves in place | - | - |
| Changes in timing and other | 94 | - |
| **Balance December 31, 2006 (Successor) (1)** | $ 722 | $ - |

(1) Excludes non-consent properties

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**Rosetta Resources, Inc.**
**Selected Data (Unaudited)**
**Quarterly Information (Unaudited)**

Summaries of the Company's results of operations by quarter for the years ended 2006 and 2005 are as follows:

| | Successor (1) 2006 | | | |
|---|---|---|---|---|
| | **First Quarter** | **Second Quarter** | **Third Quarter** | **Fourth Quarter** |
| | **(In thousands, except per share data)** | | | |
| Revenues | $ 64,544 | $ 63,381 | $ 71,197 | $ 72,641 |
| Operating Income | 18,452 | 19,438 | 22,530 | 24,717 |
| Net Income | 9,526 | 9,964 | 11,922 | 13,196 |
| Basic earnings per share | $ 0.19 | $ 0.20 | $ 0.24 | $ 0.26 |
| Diluted earnings per share | $ 0.19 | $ 0.20 | $ 0.24 | $ 0.26 |

| | **Predecessor (1)** | | **Successor (1)** | |
|---|---|---|---|---|
| | **2005** | | | |
| | **First Quarter** | **Second Quarter** | **Third Quarter** | **Fourth Quarter** |
| | **(In thousands, except per share data)** | | | |
| Revenues | $ 50,555 | $ 53,276 | $ 57,865 | $ 55,239 |
| Operating Income | 20,449 | 16,414 | 17,240 | 18,363 |
| Net Income | 10,662 | 8,019 | 8,207 | 9,328 |
| Basic earnings per share | $ 0.21 | $ 0.16 | $ 0.16 | $ 0.19 |
| Diluted earnings per share | $ 0.21 | $ 0.16 | $ 0.16 | $ 0.19 |

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(1) Differences in accounting principles of the predecessor and successor exist and will affect the comparability of the data. Differences primarily relate to the full cost method of accounting adopted by the Company and the successful efforts method of accounting followed by the predecessor and differences in accounting for stock based compensation. See Note 3.

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**Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure**

None

**Item 9A. Controls and Procedures**

**Disclosure Controls and Procedures**

Under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, we conducted an evaluation of the effectiveness of the design and operation of our disclosure controls and procedures, as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended ("Exchange Act"), as of December 31, 2006. Disclosure controls and procedures are those controls and procedures designed to provide reasonable assurance that the information required to be disclosed in our Exchange Act filings is (1) recorded, processed, summarized and reported within the time periods specified in Securities and Exchange Commission's rules and forms, and (2) accumulated and communicated to management, including our Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure.

Based on that evaluation, the Chief Executive Officer and Chief Financial Officer concluded that, as of December 31, 2006, our disclosure controls and procedures were effective, at the reasonable assurance level, and the material weaknesses in internal control over financial reporting specifically identified as of September 30, 2006 and described below have been successfully remediated in the fourth quarter of 2006. We believe our audited Consolidated/Combined Financial Statements included in this annual filing on Form 10-K fairly present in all material respects our financial position, results of operations and cash flows for the periods presented in accordance with generally accepted accounting principles as applicable to annual reporting.

In preparing our Exchange Act filings, including this annual filing on Form 10-K, we implemented processes and procedures to provide reasonable assurance that the identified material weaknesses in our internal control over financial reporting at September 30, 2006 were remediated in the fourth quarter of 2006 with respect to the information that we are required to disclose. As a result, we believe, and our Chief Executive Officer and Chief Financial Officer have certified to the best of their knowledge, that this annual filing on Form 10-K does not contain any untrue statements of material fact or omit to state any material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered in this report.

**Material Weaknesses in Internal Control Over Financial Reporting**

A material weakness is a control deficiency, or combination of control deficiencies, that results in more than a remote likelihood that a material misstatement of the annual or interim financial statements will not be prevented or detected. We had identified various deficiencies in internal control over financial reporting. We believe that many of these were attributable to our transition from a subsidiary of a much larger company to a stand alone entity. In connection with the preparation of our Consolidated/Combined Financial Statements and our assessment of the effectiveness of our disclosure controls and procedures as of December 31, 2006 to be included in this Annual Report on Form 10-K to be filed under the Exchange Act, we have remediated the following specific control deficiencies, which represented material weaknesses in our internal control over financial reporting as of September 30, 2006:

a) Prior to our effective remediation, we did not have a sufficient complement of permanent personnel to have an appropriate accounting and financial reporting organizational structure to support the activities of the Company. Specifically, we did not have permanent personnel with an appropriate level of accounting knowledge, experience and training in the selection, application and implementation of generally accepted accounting principles and financial reporting commensurate with our financial reporting requirements; and

b) Prior to our effective remediation, we did not have effective controls as it relates to the identification and documentation of accounting policies, including selection and application of generally accepted accounting principles used for accounting for select transactions and other activities. This deficiency resulted in a reduced ability to ensure the timely and accurate recording of certain transactions and activities primarily relating to accounting for derivatives and debt modifications. As a result, we did not have sufficient procedures to ensure significant underlying select transactions were appropriately and timely accounted for in the general ledger.

These material weaknesses could have resulted in a misstatement of certain accounts and disclosures which would result in a material misstatement of interim financial statements that would not be prevented or detected. Accordingly, management concluded at the time of assessment that these control deficiencies constituted material weaknesses as of December 31, 2005, March 31, 2006 and June 30, 2006.

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**Remediation Activities**

As discussed above, management identified certain material weaknesses that existed in our internal control over financial reporting and took steps to strengthen our internal control over financial reporting. Starting in January 2006, we began hiring additional qualified accounting personnel and completed our staffing program in the third quarter of 2006. Our documentation of accounting procedures and key policies was complete at December 31, 2006. Specifically, the remedial actions were as follows:

1. We employed a certified public accountant from one of the top tier Accounting Firms to be the manager of financial reporting;

2. We employed a person to fill the position of manager of internal audit to review and audit our internal control environment and make recommendations for improvement;

3. We have replaced our manager of fixed assets and accounts payable with a more highly credentialed person having a masters degree in business administration who is also a certified public accountant;

4. We employed a certified public accountant with top tier Accounting firm and industry experience to fill the position of oil and gas property analyst;

5. We employed a certified public accountant with specific expertise in accounting software systems to evaluate and implement further enhancements to our software and related procedures to improve our accounting control;

6. We employed two supervisory level accountants who have extensive industry experience;

7. We engaged a national tax consulting firm to review our accounting for certain transactions and disclosures; and

8. We have substantially completed the initial documentation of our internal accounting procedures, controls and key policies as part of our process of compliance as required for the year ended December 31, 2007, pursuant to Section 404 of the Sarbanes-Oxley Act.

Beginning with the year ending December 31, 2007, pursuant to Section 404 of the Sarbanes-Oxley Act, we will be required to deliver a report that assesses the effectiveness of our internal control over financial reporting, and our auditors will be required to audit and report on our assessment of and the effectiveness of our internal control over financial reporting. We have completed the initial documentation phase of our control process and will begin testing of our internal control over financial reporting in the second quarter of 2007 and will seek to remediate any additional material weaknesses, if any, identified during that activity. Furthermore, we believe we have a program in place which will be compliant by December 2007 with Section 404 of the Sarbanes-Oxley Act. However, it is possible we may not be able to complete the required management assessment or remediation by our reporting deadline. An inability to complete this assessment would result in receiving something other than an unqualified report from our auditors with respect to our assessment of our internal control over financial reporting. In addition, if material weaknesses are not remediated, we would not be able to conclude that our internal control over financial reporting was effective, which would result in the inability of our external auditors to deliver an unqualified report on the effectiveness of our internal control over financial reporting.

**Item 9B. Other Information**

None

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## PART III

### Item 10. Directors, Executive Officers and Corporate Governance

The information required to be contained in this Item is incorporated by reference from Part I of this report and by reference to our definitive proxy statement to be filed with respect to our 2007 annual meeting.

### Item 11. Executive Compensation

The information required to be contained in this Item is incorporated by reference to our definitive proxy statement to be filed with respect to our 2007 annual meeting under the heading “Executive Compensation”.

### Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

This information required to be contained in this Item is incorporated by reference to our definitive proxy statement to be filed with respect to our 2007 annual meeting under the heading “Principal Stockholders and Security Ownership of Management”.

### Item 13. Certain Relationships and Related Transactions, and Director Independence

The information required to be contained in this Item is incorporated by reference to our definitive proxy statement to be filed with respect to our 2007 annual meeting under the heading “Certain Transactions”.

### Item 14. Principal Accountant Fees and Services

The information required to be contained in this Item is incorporated by reference to our definitive proxy statement to be filed with respect to our 2007 annual meeting.

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**Part IV**

**Item 15. Exhibits and Financial Statement Schedules**

(a) The following documents are filed as a part of this report or incorporated herein by reference:

(1) Our Consolidated/Combined Financial Statements are listed on page 49 of this report.

(2) Financial Statement Schedules:

None

(3) Exhibits:

The following documents are included as exhibits to this report:

| **Exhibit Number** | **Description** |
|---|---|
| 3.1 | Certificate of Incorporation (incorporated herein by reference to Exhibit 3.1 to the Company's Registration Statement on Form S-1 filed on October 7, 2005 (Registration No. 333-128888)). |
| 3.2 | Bylaws (incorporated herein by reference to Exhibit 3.2 to the Company's Registration Statement on Form S-1 filed on October 7, 2005 (Registration No. 333-128888)). |
| 4.1 | Registration Rights Agreement (incorporated herein by reference to Exhibit 4.1 to the Company's Registration Statement on Form S-1 filed on October 7, 2005 (Registration No. 333-128888)). |
| 10.1 | Purchase and Sale Agreement with Calpine Corporation, Calpine Gas Holdings, L.L.C. and Calpine Fuels Corporation (incorporated herein by reference to Exhibit 10.1 to the Company's Registration Statement on Form S-1 filed on October 7, 2005 (Registration No. 333-128888)). |
| 10.2 | Transfer and Assumption Agreements with Calpine Corporation and Subsidiaries of Rosetta Resources Inc. (incorporated herein by reference to Exhibit 10.2 to the Company's Registration Statement on Form S-1 filed on October 7, 2005 (Registration No. 333-128888)). |
| 10.4 | Gas Purchase and Sale Contract with Calpine Energy Services, L.P. (incorporated herein by reference to Exhibit 10.4 to the Company's Registration Statement on Amendment No. 1 to Form S-1 filed on January 3, 2006 (Registration No. 333-128888)). |
| 10.5 | Services Agreement with Calpine Producer Services, L.P. (incorporated herein by reference to Exhibit 10.5 to the Company's Registration Statement on Form S-1 filed on October 7, 2005 (Registration No. 333-128888)). |
| 10.9** | 2005 Long-Term Incentive Plan (incorporated herein by reference to Exhibit 10.9 to the Company's Registration Statement on Form S-1 filed on October 7, 2005 (Registration No. 333-128888)). |
| 10.10** | Form of Option Grant Agreement (incorporated herein by reference to Exhibit 10.10 to the Company's Registration Statement on Form S-1 filed on October 7, 2005 (Registration No. 333-128888)). |

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| **Exhibit Number** | **Description** |
|---|---|
| 10.11** | Form of Restricted Stock Agreement (incorporated herein by reference to Exhibit 10.11 to the Company's Registration Statement on Form S-1 filed on October 7, 2005 (Registration No. 333-128888)). |
| 10.12** | Form of Bonus Restricted Stock Agreement (incorporated herein by reference to Exhibit 10.12 to the Company's Registration Statement on Form S-1 filed on October 7, 2005 (Registration No. 333-128888)). |
| 10.13** | Employment Agreement with B.A. Berilgen (incorporated herein by reference to Exhibit 10.13 to the Company's Registration Statement on Form S-1 filed on October 7, 2005 (Registration No. 333-128888)). |
| 10.14** | Amended and Restated Employment Agreement with Michael J. Rosinski (incorporated herein by reference to Exhibit 10.14 to the Company's Registration Statement on Form S-1 filed on October 7, 2005 (Registration No. 333-128888)). |
| 10.15** | Employment Agreement with Charles F. Chambers (incorporated herein by reference to Exhibit 10.15 to the Company's Registration Statement on Form S-1 filed on October 7, 2005 (Registration No. 333-128888)). |
| 10.16** | Employment Agreement with Edward E. Seeman (incorporated herein by reference to Exhibit 10.16 to the Company's Registration Statement on Form S-1 filed on October 7, 2005 (Registration No. 333-128888)). |
| 10.17** | Employment Agreement with Michael H. Hickey (incorporated herein by reference to Exhibit 10.17 to the Company's Registration Statement on Form S-1 filed on October 7, 2005 (Registration No. 333-128888)). |
| 10.18 | Senior Revolving Credit Agreement (incorporated herein by reference to Exhibit 10.18 to the Company's Registration Statement on Form S-1 filed on October 7, 2005 (Registration No. 333-128888)). |
| 10.19 | Second Lien Term Loan Agreement (incorporated herein by reference to Exhibit 10.19 to the Company's Registration Statement on Form S-1 filed on October 7, 2005 (Registration No. 333-128888)). |
| 10.20 | Guarantee and Collateral Agreement (incorporated herein by reference to Exhibit 10.20 to the Company's Registration Statement on Form S-1 filed on October 7, 2005 (Registration No. 333-128888)). |
| 10.21 | Second Lien Guarantee and Collateral Agreement (incorporated herein by reference to Exhibit 10.21 to the Company's Registration Statement on Form S-1 filed on October 7, 2005 (Registration No. 333-128888)). |
| 10.22 | First Amendment to Senior Revolving Credit Agreement (incorporated herein by reference to Exhibit 10.22 to the Company's Registration Statement on Form S-1 filed on October 7, 2005 (Registration No. 333-128888)). |
| 10.23 | First Amendment to Second Lien Term Loan Agreement (incorporated herein by reference to Exhibit 10.23 to the Company's Registration Statement on Form S-1 filed on October 7, 2005 (Registration No. 333-128888)). |
| 10.24 | First Amendment to Guarantee and Collateral Agreement (incorporated herein by reference to Exhibit 10.24 to the Company's Registration Statement on Form S-1 filed on October 7, 2005 (Registration No. 333-128888)). |

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| Exhibit Number | Description |
|---|---|
| 10.25 | First Amendment to Second Lien Guarantee and Collateral Agreement (incorporated herein by reference to Exhibit 10.25 to the Company's Registration Statement on Form S-1 filed on October 7, 2005 (Registration No. 333-128888)). |
| 10.26 | Deposit Account Control Agreement (incorporated herein by reference to Exhibit 10.26 to the Company's Registration Statement on Form S-1 filed on October 7, 2005 (Registration No. 333-128888)). |
| 10.27** | Amendment No. 1 to B.A. Berilgen Employment Agreement (incorporated herein by reference to Exhibit 10.27 to the Company's Registration Statement on Amendment No. 1 to Form S-1 filed on January 3, 2006 (Registration No. 333-128888)). |
| 10.28** | First Amendment to 2005 Long-Term Incentive Plan (incorporated herein by reference to Exhibit 10.28 to the Company's Registration Statement on Amendment No. 1 to Form S-1 filed on January 3, 2006 (Registration No. 333-128888)). |
| 10.29** | Non-Executive Employee Change of Control Plan (incorporated herein by reference to Exhibit 10.29 to the Company's Registration Statement on Amendment No. 1 to Form S-1 filed on January 3, 2006 (Registration No. 333-128888)). |
| 14.1 | Code of Ethics posted on the Company's website at *www.rosettaresources.com.* |
| 21.1* | Subsidiaries of the registrant |
| 23.1* | Consent of PricewaterhouseCoopers LLP |
| 23.2* | Consent of PricewaterhouseCoopers LLP |
| 23.3* | Consent of Netherland, Sewell & Associates, Inc. |
| 31.1* | Certification of Periodic Financial Reports by B.A. Berilgen in satisfaction of Section 302 of the Sarbanes-Oxley Act of 2002. |
| 31.2* | Certification of Periodic Financial Reports by Michael J. Rosinski in satisfaction of Section 302 of the Sarbanes-Oxley Act of 2002. |
| 32.1* | Certification of Periodic Financial Reports by B.A. Berilgen and Michael J. Rosinski in satisfaction of Section 906 of the Sarbanes-Oxley Act of 2002. |

* Filed herewith

** Management contract or compensatory plan or arrangement required to be filed as an exhibit hereto.

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## Signatures

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized, on March 16, 2007.

ROSETTA RESOURCES INC.
By: /s/ B.A. Berilgen
B.A. Berilgen, Chairman of the Board, President and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1933, this report has been signed below by the following persons on behalf of the registrant and in the capacity and on the dates indicated:

| Signature | Title | Date |
|---|---|---|
| /s/ B. A. Berilgen<br>B. A. Berilgen | Chairman of the Board, President and Chief Executive Officer (Principal Executive Officer) | March 16, 2007 |
| /s/ Michael J. Rosinski<br>Michael J. Rosinski | Executive Vice President and Chief Financial Officer (Principal Financial Officer) | March 16, 2007 |
| /s/ Denise D. Bednorz<br>Denise D. Bednorz | Vice President, Controller (Principal Accounting Officer) | March 16, 2007 |
| /s/ Richard W. Beckler<br>Richard W. Beckler | Director | March 16, 2007 |
| /s/ Donald D. Patteson, Jr.<br>Donald D. Patteson, Jr. | Director | March 16, 2007 |
| /s/ D. Henry Houston<br>D. Henry Houston | Director | March 16, 2007 |
| /s/ G. Louis Graziadio, III<br>G. Louis Graziadio, III | Director | March 16, 2007 |
| /s/ Josiah O. Low, III<br>Josiah O. Low, III | Director | March 16, 2007 |

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## Glossary of Oil and Natural Gas Terms

We are in the business of exploring for and producing oil and natural gas. Oil and gas exploration is a specialized industry. Many of the terms used to describe our business are unique to the oil and natural gas industry. The following is a description of the meanings of some of the oil and natural gas industry terms used in this report.

**3-D Seismic**. (Three-Dimensional Seismic Data) Geophysical data that depicts the subsurface strata in three dimensions. 3-D seismic data typically provides a more detailed and accurate interpretation of the subsurface strata than two-dimensional seismic data.

***Amplitude***. The difference between the maximum displacement of a seismic wave and the point of no displacement, or the null point.

***(Amplitude plays) anomalies***. An abrupt increase in seismic amplitude that can in some instances indicate the presence of hydrocarbons.

***Anticline***. An arch-shaped fold in rock in which layers are upwardly convex, often forming a hydrocarbon trap. Anticlines may form hydrocarbon traps, particularly in folds with reservoir-quality rocks in their core and impermeable seals in the outer layers of the fold.

***Appraisal well***. A well drilled several spacing locations away from a producing well to determine the boundaries or extent of a productive formation and to establish the existence of additional reserves.

***Bbl***. One stock tank barrel, or 42 U.S. gallons liquid volume, of oil or other liquid hydrocarbons.

***Bcf***. Billion cubic feet of natural gas.

***Bcfe***. Billion cubic feet equivalent determined using the ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or natural gas liquids.

***Behind Pipe Pays***. Reserves expected to be recovered from zones in existing wells, which will require additional completion work or future recompletion prior to the start of production.

***Block***. A block depicted on the Outer Continental Shelf Leasing and Official Protraction Diagrams issued by the U.S. Minerals Management Service or a similar depiction on official protraction or similar diagrams, issued by a state bordering on the Gulf of Mexico.

***Btu or British thermal unit***. The quantity of heat required to raise the temperature of one pound of water by one degree Fahrenheit.

***Coalbed methane***. Coal is a carbon-rich sedimentary rock that forms from the remains of plants deposited as peat in swampy environments. Natural gas associated with coal, called coal gas or coalbed methane, can be produced economically from coal beds in some areas.

***Completion***. The installation of permanent equipment for the production of oil or natural gas.

***Developed acreage***. The number of acres that are allocated or assignable to productive wells or wells capable of production.

***Development well***. A well drilled within the proved boundaries of an oil or natural gas reservoir with the intention of completing the stratigraphic horizon known to be productive.

***Dry hole***. A well found to be incapable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production exceeds production expenses and taxes.

***Dry hole costs***. Costs incurred in drilling a well, assuming a well is not successful, including plugging and abandonment costs.

***Exploratory well***. A well drilled to find and produce oil or natural gas reserves not classified as proved, to find a new reservoir in a field previously found to be productive of oil or natural gas in another reservoir or to extend a known reservoir.

***Farmout.*** An agreement whereby the owner of a leasehold or working interest agrees to assign an interest in certain specific acreage to the assignees, retaining an interest such as an overriding royalty interest, an oil and gas payment, offset acreage or other type of interest, subject to the drilling of one or more specific wells or other performance as a condition of the assignment

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***Fault***. A break or planar surface in brittle rock across which there is observable displacement.

***Faulted downthrown rollover anticline***. An arch-shaped fold in rock in which the convex geological structure is tipped as opposed to perpendicular to the ground and in which a visible break or displacement has occurred in brittle rock, often forming a hydrocarbon trap.

***Field.*** An area consisting of either a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition.

***Finding and development costs.*** Capital costs incurred in the acquisition, exploration, development and revisions of proved oil and natural gas reserves divided by proved reserve additions.

***Fracing or fracture stimulation technology.*** The technique of improving a well's production or injection rates by pumping a mixture of fluids into the formation and rupturing the rock, creating an artificial channel. As part of this technique, sand or other material may also be injected into the formation to keep the channel open, so that fluids or natural gases may more easily flow through the formation.

***Gross acres or gross wells.*** The total acres or wells, as the case may be, in which a working interest is owned.

***Horizontal drilling.*** A drilling operation in which a portion of the well is drilled horizontally within a productive or potentially productive formation. This operation usually yields a well that has the ability to produce higher volumes than a vertical well drilled in the same formation.

***Hydrocarbon indicator.*** A type of seismic amplitude anomaly, seismic event, or characteristic of seismic data that can occur in a hydrocarbon-bearing reservoir.

***Infill well.*** A well drilled between known producing wells to better exploit the reservoir.

***Injection well or injection.*** A well which is used to place liquids or natural gases into the producing zone during secondary/tertiary recovery operations to assist in maintaining reservoir pressure and enhancing recoveries from the field.

***Lease operating expenses.*** The expenses of lifting oil or natural gas from a producing formation to the surface, constituting part of the current operating expenses of a working interest, and also including labor, superintendence, supplies, repairs, short-lived assets, maintenance, allocated overhead costs, workover, ad valorem taxes, insurance and other expenses incidental to production, but excluding lease acquisition or drilling or completion expenses.

***MBbls.*** Thousand barrels of crude oil or other liquid hydrocarbons.

***Mcf.*** Thousand cubic feet of natural gas.

***Mcfe.*** Thousand cubic feet equivalent determined using the ratio of six Mcf of natural gas to one Bbl of oil, condensate or natural gas liquids.

***MMBbls.*** Million barrels of oil or other liquid hydrocarbons.

***MMBtu.*** Million British Thermal Units.

***MMcf.*** Million cubic feet of natural gas.

***MMcfe.*** Million cubic feet equivalent determined using the ratio of six Mcf of natural gas to one Bbl of oil, condensate or natural gas liquids.

***Net acres or net wells.*** The sum of the fractional working interests owned in gross acres or wells, as the case may be.

***Net revenue interest.*** An interest in all oil and natural gas produced and saved from, or attributable to, a particular property, net of all royalties, overriding royalties, net profits interests, carried interests, reversionary interests and any other burdens to which the person’s interest is subject.

***Nonoperated working interests.*** The working interest or fraction thereof in a lease or unit, the owner of which is without operating rights by reason of an operating agreement.

***NYMEX.*** New York Mercantile Exchange.

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***OCS block.*** Outer continental shelf block located outside the state territorial limit.

***Operated working interests.*** Where the working interests for a property are co-owned, and where more than one party elects to participate in the development of a lease or unit, there is an operator designated "for full control of all operations within the limits of the operating agreement" for the development and production of the wells on the co-owned interests. The working interests of the operating party become the "operated working interests."

***Payout.*** Generally refers to the recovery by the incurring party of its costs of drilling, completing, equipping and operating a well before another party's participation in the benefits of the well commences or is increased to a new level.

***Permeability.*** The ability, or measurement of a rock's ability, to transmit fluids, typically measured in darcies or millidarcies. Formations that transmit fluids readily are described as permeable and tend to have many large, well-connected pores.

***Porosity.*** The percentage of pore volume or void space, or that volume within rock that can contain fluids.

***PV-10 or present value of estimated future net revenues.*** An estimate of the present value of the estimated future net revenues from proved oil and natural gas reserves at a date indicated after deducting estimated production and ad valorem taxes, future capital costs and operating expenses, but before deducting any estimates of federal income taxes. The estimated future net revenues are discounted at an annual rate of 10%, in accordance with the Securities and Exchange Commission's practice, to determine their "present value." The present value is shown to indicate the effect of time on the value of the revenue stream and should not be construed as being the fair market value of the properties. Estimates of future net revenues are made using oil and natural gas prices and operating costs at the date indicated and held constant for the life of the reserves.

***Productive well.*** A well that is found to be capable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production exceed production expenses and taxes.

***Progradation.*** The accumulation of sequences by deposition in which beds are deposited successively basinward because sediment supply exceeds accommodation.

***Prospect.*** A specific geographic area which, based on supporting geological, geophysical or other data and also preliminary economic analysis using reasonably anticipated prices and costs, is deemed to have potential for the discovery of commercial hydrocarbons.

***Proved developed non-producing reserves.*** Proved developed reserves expected to be recovered from zones behind casing in existing wells. See Rule 4-10(a), paragraph (2) through (2)iii for a more complete definition.

***Proved developed producing reserves.*** Proved developed reserves that are expected to be recovered from completion intervals currently open in existing wells and capable of production to market. See Rule 4-10(a), paragraph (2) through (2)iii for a more complete definition.

***Proved developed reserves.*** Proved reserves that can be expected to be recovered from existing wells with existing equipment and operating methods. See Rule 4-10(a), paragraph (3) for a more complete definition.

***Proved reserves.*** The estimated quantities of oil, natural gas and natural gas liquids that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. See Rule 4-10(a), paragraph (2) through (2)iii for a more complete definition.

***Proved undeveloped reserves.*** Proved reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion. See Rule 4-10(a), paragraph (4) for a more complete definition.

***Reserve life index.*** This index is calculated by dividing year-end reserves by the average production during the past year to estimate the number of years of remaining production.

***Reservoir.*** A porous and permeable underground formation containing a natural accumulation of producible oil and/or natural gas that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.

***Resistivity.*** The ability of a material to resist electrical conduction. Resistivity is used to indicate the presence of water and /or hydrocarbons.

***Secondary recovery.*** An artificial method or process used to restore or increase production from a reservoir after the primary production by the natural producing mechanism and reservoir pressure has experienced partial depletion. Natural gas injection and waterflooding are examples of this technique.

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***Shelf.*** Areas in the Gulf of Mexico with depths less than 1,300 feet. Our shelf area and operations also includes a small amount of properties and operations in the onshore and bay areas of the Gulf Coast.

***Stratigraphy.*** The study of the history, composition, relative ages and distribution of layers of the earth's crust.

***Stratigraphic trap.*** A sealed geologic container capable of retaining hydrocarbons that was formed by changes in rock type or pinch-outs, unconformities, or sedimentary features such as reefs.

***Tcf.*** Trillion cubic feet of natural gas.

***Tcfe.*** Trillion cubic feet equivalent determined using the ratio of six Mcf of natural gas to one Bbl of oil, condensate or natural gas liquids.

***Trap.*** A configuration of rocks suitable for containing hydrocarbons and sealed by a relatively impermeable formation through which hydrocarbons will not escape.

***Undeveloped acreage.*** Lease acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil or natural gas regardless of whether or not such acreage contains proved reserves.

***Waterflooding.*** A secondary recovery operation in which water is injected into the producing formation in order to maintain reservoir pressure and force oil toward and into the producing wells.

***Working interest.*** The operating interest that gives the owner the right to drill, produce and conduct operating activities on the property and receive a share of production.

***Workover.*** The repair or stimulation of an existing production well for the purpose of restoring, prolonging or enhancing the production of hydrocarbons.

***Workover rig.*** A portable rig used to repair or adjust downhole equipment on an existing well.

***/d.***"Per day" when used with volumetric units or dollars.

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**Index to Exhibits**

| Exhibit Number | Description |
| --- | --- |
| 3.1 | Certificate of Incorporation (incorporated herein by reference to Exhibit 3.1 to the Company's Registration Statement on Form S-1 filed on October 7, 2005 (Registration No. 333-128888)). |
| 3.2 | Bylaws (incorporated herein by reference to Exhibit 3.2 to the Company's Registration Statement on Form S-1 filed on October 7, 2005 (Registration No. 333-128888)). |
| 4.1 | Registration Rights Agreement (incorporated herein by reference to Exhibit 4.1 to the Company's Registration Statement on Form S-1 filed on October 7, 2005 (Registration No. 333-128888)). |
| 10.1 | Purchase and Sale Agreement with Calpine Corporation, Calpine Gas Holdings, L.L.C. and Calpine Fuels Corporation (incorporated herein by reference to Exhibit 10.1 to the Company's Registration Statement on Form S-1 filed on October 7, 2005 (Registration No. 333-128888)). |
| 10.2 | Transfer and Assumption Agreements with Calpine Corporation and Subsidiaries of Rosetta Resources Inc. (incorporated herein by reference to Exhibit 10.2 to the Company's Registration Statement on Form S-1 filed on October 7, 2005 (Registration No. 333-128888)). |
| 10.4 | Gas Purchase and Sale Contract with Calpine Energy Services, L.P. (incorporated herein by reference to Exhibit 10.4 to the Company's Registration Statement on Amendment No. 1 to Form S-1 filed on January 3, 2006 (Registration No. 333-128888)). |
| 10.5 | Services Agreement with Calpine Producer Services, L.P. (incorporated herein by reference to Exhibit 10.5 to the Company's Registration Statement on Form S-1 filed on October 7, 2005 (Registration No. 333-128888)). |
| 10.9** | 2005 Long-Term Incentive Plan (incorporated herein by reference to Exhibit 10.9 to the Company's Registration Statement on Form S-1 filed on October 7, 2005 (Registration No. 333-128888)). |
| 10.10** | Form of Option Grant Agreement (incorporated herein by reference to Exhibit 10.10 to the Company's Registration Statement on Form S-1 filed on October 7, 2005 (Registration No. 333-128888)). |
| 10.11** | Form of Restricted Stock Agreement (incorporated herein by reference to Exhibit 10.11 to the Company's Registration Statement on Form S-1 filed on October 7, 2005 (Registration No. 333-128888)). |

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| Exhibit Number | Description |
|---|---|
| 10.12** | Form of Bonus Restricted Stock Agreement (incorporated herein by reference to Exhibit 10.12 to the Company's Registration Statement on Form S-1 filed on October 7, 2005 (Registration No. 333-128888)). |
| 10.13** | Employment Agreement with B.A. Berilgen (incorporated herein by reference to Exhibit 10.13 to the Company's Registration Statement on Form S-1 filed on October 7, 2005 (Registration No. 333-128888)). |
| 10.14** | Amended and Restated Employment Agreement with Michael J. Rosinski (incorporated herein by reference to Exhibit 10.14 to the Company's Registration Statement on Form S-1 filed on October 7, 2005 (Registration No. 333-128888)). |
| 10.15** | Employment Agreement with Charles F. Chambers (incorporated herein by reference to Exhibit 10.15 to the Company's Registration Statement on Form S-1 filed on October 7, 2005 (Registration No. 333-128888)). |
| 10.16** | Employment Agreement with Edward E. Seeman (incorporated herein by reference to Exhibit 10.16 to the Company's Registration Statement on Form S-1 filed on October 7, 2005 (Registration No. 333-128888)). |
| 10.17** | Employment Agreement with Michael H. Hickey (incorporated herein by reference to Exhibit 10.17 to the Company's Registration Statement on Form S-1 filed on October 7, 2005 (Registration No. 333-128888)). |
| 10.18 | Senior Revolving Credit Agreement (incorporated herein by reference to Exhibit 10.18 to the Company's Registration Statement on Form S-1 filed on October 7, 2005 (Registration No. 333-128888)). |
| 10.19 | Second Lien Term Loan Agreement (incorporated herein by reference to Exhibit 10.19 to the Company's Registration Statement on Form S-1 filed on October 7, 2005 (Registration No. 333-128888)). |
| 10.20 | Guarantee and Collateral Agreement (incorporated herein by reference to Exhibit 10.20 to the Company's Registration Statement on Form S-1 filed on October 7, 2005 (Registration No. 333-128888)). |
| 10.21 | Second Lien Guarantee and Collateral Agreement (incorporated herein by reference to Exhibit 10.21 to the Company's Registration Statement on Form S-1 filed on October 7, 2005 (Registration No. 333-128888)). |
| 10.22 | First Amendment to Senior Revolving Credit Agreement (incorporated herein by reference to Exhibit 10.22 to the Company's Registration Statement on Form S-1 filed on October 7, 2005 (Registration No. 333-128888)). |
| 10.23 | First Amendment to Second Lien Term Loan Agreement (incorporated herein by reference to Exhibit 10.23 to the Company's Registration Statement on Form S-1 filed on October 7, 2005 (Registration No. 333-128888)). |
| 10.24 | First Amendment to Guarantee and Collateral Agreement (incorporated herein by reference to Exhibit 10.24 to the Company's Registration Statement on Form S-1 filed on October 7, 2005 (Registration No. 333-128888)). |
| 10.25 | First Amendment to Second Lien Guarantee and Collateral Agreement (incorporated herein by reference to Exhibit 10.25 to the Company's Registration Statement on Form S-1 filed on October 7, 2005 |

(Registration No. 333-128888)).

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| Exhibit Number | Description |
|---|---|
| 10.26 | Deposit Account Control Agreement (incorporated herein by reference to Exhibit 10.26 to the Company’s Registration Statement on Form S-1 filed on October 7, 2005 (Registration No. 333-128888)). |
| 10.27** | Amendment No. 1 to B.A. Berilgen Employment Agreement (incorporated herein by reference to Exhibit 10.27 to the Company’s Registration Statement on Amendment No. 1 to Form S-1 filed on January 3, 2006 (Registration No. 333-128888)). |
| 10.28** | First Amendment to 2005 Long-Term Incentive Plan (incorporated herein by reference to Exhibit 10.28 to the Company’s Registration Statement on Amendment No. 1 to Form S-1 filed on January 3, 2006 (Registration No. 333-128888)). |
| 10.29** | Non-Executive Employee Change of Control Plan (incorporated herein by reference to Exhibit 10.29 to the Company’s Registration Statement on Amendment No. 1 to Form S-1 filed on January 3, 2006 (Registration No. 333-128888)). |
| 14.1 | Code of Ethics posted on the Company’s website at *www.rosettaresources.com*. |
| 21.1* | Subsidiaries of the registrant |
| 23.1* | Consent of PricewaterhouseCoopers LLP |
| 23.2* | Consent of PricewaterhouseCoopers LLP |
| 23.3* | Consent of Netherland, Sewell & Associates, Inc. |
| 31.1* | Certification of Periodic Financial Reports by B.A. Berilgen in satisfaction of Section 302 of the Sarbanes-Oxley Act of 2002. |
| 31.2* | Certification of Periodic Financial Reports by Michael J. Rosinski in satisfaction of Section 302 of the Sarbanes-Oxley Act of 2002. |
| 32.1* | Certification of Periodic Financial Reports by B.A. Berilgen and Michael J. Rosinski in satisfaction of Section 906 of the Sarbanes-Oxley Act of 2002. |

* Filed herewith
** Management contract or compensatory plan or arrangement required to be filed as an exhibit hereto.