Rosetta Resources Inc.
Form 10-K
February 29, 2008

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

FORM 10-K

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

For The Fiscal Year Ended December 31, 2007

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 (State or other jurisdiction of incorporation or organization)	43-2083519 (I.R.S. Employer Identification No.)
717 Texas, Suite 2800, Houston, TX (Address of principal executive offices)	77002 (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 (Title of Class)	The Nasdaq Stock Market LLC (Nasdaq Global Select Market) (Name of Exchange on which registered)

Securities Registered 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 Exchange Act. Yes S No £

Indicate by check mark if the Registrant is not required to file reports pursuant to Section 13 or 15(d) of the Exchange Act. Yes £ No S

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 S 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. S

Indicate by check mark whether the Registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer S	Accelerated filer £
Non-Accelerated filer £	Smaller Reporting Company £
(Do not check if smaller reporting company)	

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

The aggregate market value of the voting and non-voting common equity held by Non-affiliates of the registrant as of June 29, 2007 was approximately $1.1 billion based on the closing price of $21.54 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 February 18, 2008 was 51,146,322.

Documents Incorporated By Reference

Information required by Part III will either be included in Rosetta Resources Inc. 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 95.

Part I

Item 1. Business

General

We are an independent oil and gas company engaged in the acquisition, exploration, development and production of oil and gas properties in North America. Our operations are concentrated in the Sacramento Basin of California, the Rocky Mountains, the Lobo and Perdido trends in South Texas, the State Waters of Texas and the Gulf of Mexico. We are a Delaware corporation based in Houston, Texas.

Rosetta Resources Inc. (together with our consolidated subsidiaries, the "Company") was formed in June 2005 to acquire Calpine Natural Gas L.P., its partners and the domestic oil and natural gas business formerly owned by Calpine Corporation and its affiliates ("Calpine"). We ("Successor") acquired Calpine Natural Gas L.P. and its partners ("Predecessor") and Rosetta Resources California, LLC, Rosetta Resources Rockies, LLC, Rosetta Resources Offshore, LLC and Rosetta Resources Texas LP and its partners, in July 2005 (hereinafter, the "Acquisition"). We have subsequently acquired numerous other oil and natural gas properties, and we are engaged in oil and natural gas exploration, development, production and acquisition activities in the United States. We operate in one business segment. See Note 15 to our consolidated/combined financial statements. We have grown our existing property base by developing and exploring our acreage; purchasing new undeveloped leases; acquiring oil and gas producing properties and drilling prospects from third parties.

Pursuant to the Acquisition, we entered into several operative contracts with Calpine, including a purchase and sale agreement and all interrelated agreements, concurrently executed on or about July 7, 2005 (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 original term ran through June 30, 2007. In connection with the partial transfer and release agreement executed by Calpine and the Company on August 3, 2007 (the "PTRA"), a new marketing agreement was entered into whose term is from July 1, 2007 through June 30, 2009, subject to earlier termination on certain events. 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 Purchase Agreement. The PTRA and gas purchase and sales contracts with Calpine are discussed further under Part I. Item 3. Legal Proceedings.

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, the Rocky Mountains, South Texas, the State Waters of Texas and the Gulf of Mexico. 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. We also believe our current asset base provides a strong platform for additional acquisitions.

Development and Exploration Drilling Inventory. We have identified an inventory of low to moderate risk opportunities providing us with multiple years of drilling, and we expect to drill approximately 190 of these locations during 2008. Approximately 20% of these locations are classified as proved undeveloped. We also believe we have access to a large and diversified portfolio of non-proved resource inventory that will drive future growth. Our capital expenditure budget is $290.1 million for 2008. 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.

Operational Control. We operate approximately 88% 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, New Leadership. Our executive management team has an average of 29 years of experience in the energy industry with specific experience in the areas where our primary properties are located. In November 2007, Randy L. Limbacher became our President and Chief Executive Officer ("CEO") replacing B. A. Berilgen who resigned in 2007. Mr. Limbacher personally has 27 years of experience in the energy industry, most recently serving as President, Exploration and Production - Americas for ConocoPhillips.

Proven Technical and Land Personnel with Access to Technological Resources. Our technical staff includes 36 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 complex basins and managing coalbed methane operations. These core competencies helped us to achieve a drilling success rate of 82% for the year ended December 31, 2007 and has helped maximize recovery from our reservoirs. Our definition of drilling success is a well that is producing or capable of production, including natural gas wells awaiting pipeline connections to commence deliveries and oil wells awaiting connection to production facilities. Previously, our definition of a successful well was a well that produced hydrocarbons at sufficient rates to allow us to recover, at a minimum, our capital investment and operating costs. Under the previous definition, our success rate would have been 72%.

Our Strategy

Our strategy is to increase stockholder value by managing our reserves, production, cash flow and profitability using a balanced program of (1) developing and extending inventory in existing core properties, (2) establishing new resource based core areas, (3) exploitation and exploration activities, (4) completing acquisitions and selective divestitures, (5) maintaining technical expertise, (6) focusing on cost control and (7) maintaining financial flexibility. We will seek to accomplish these goals while working to protect stockholders interests by focusing on sustainability, spending our various resources wisely, monitoring emerging trends, minimizing liabilities through governmental compliance, respecting the dignity of human life, and protecting the environment. The following are key elements of our strategy:

Developing and Extending Existing Core Properties. We have designated the Sacramento Basin, the DJ Basin and South Texas as core areas and intend to build our asset base in these areas through additional leasing and acquisitions where applicable. We intend to further develop the upside potential of these core properties by working over existing wells, drilling in-fill locations, drilling step-out wells to expand known field outlines, recompleting to logged behind pipe pays and lowering field line pressures through compression for additional reserve recovery.

Establishing New Resource Based Core Areas. We intend to extend our presence into new core areas within North America that are characterized by significant presence of resource potential that can be exploited utilizing our technological expertise.

Exploitation and Exploration Activities. We intend to generate growth in existing and new core areas in which we have technological and operational advantages by identifying exploitation and exploration opportunities that contain the potential to establish repeatable drilling programs.

Completing Acquisitions and Selective Divestitures. We continually review opportunities to optimize our portfolio to create stockholder value. We actively evaluate possible acquisitions of producing properties, undeveloped acreage and drilling prospects in our existing core areas, as well as areas where we believe we can establish new core areas by implementing an “acquire and exploit” strategy. We will focus on opportunities where we believe our reservoir management and operational expertise will enhance the value and performance of the acquired properties through development and exploration based on repeatable drilling programs. Periodically, we also evaluate possible divestitures of properties that we believe have limited future potential or that do not fit our risk profile.

Maintaining Technological Expertise. We intend to maintain and further develop the technological expertise that helped us achieve a drilling success rate of 82% for the year ended December 31, 2007 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.

Focusing on Cost Control. We will manage all elements of our cost structure including drilling and operating costs as well as overhead costs. We will strive to minimize our drilling and operating costs by concentrating our assets within existing and new sustainable resource based core areas.

Maintaining Financial Flexibility. We may optimize unused borrowing capacity under our revolving line of credit by refinancing our bank debt in the capital markets if conditions are favorable. As of December 31, 2007, we had $179.0 million available for borrowing under our revolving line of credit, with $170.0 million drawn 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 continue 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 for a significant portion of our expected production through 2009. We also entered into a series of interest rate swap agreements to hedge the change in variable interest rates associated with our debt under our credit facility through June 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").

On June 29, 2006, Calpine filed a motion pursuant to Bankruptcy Code Section 365 in connection with its bankruptcy proceedings and received an order from the Bankruptcy Court approving Calpine's precautionary assumption of certain oil and gas leases which Calpine had previously sold or agreed to sell to us in the Acquisition, to the extent that the leases both constituted "unexpired leases of non-residential real property" and were not fully transferred to us at the time of Calpine's filing for bankruptcy, in order to prevent Section 365's "deemed rejection" of such leases. 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 asked to take further action or pay further consideration to complete the assignments of these interests or alternatively, Calpine might seek to 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.

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 all of which are covered, we believe, by the further assurances provision of the Purchase Agreement; however, the exact details of each property involved and how, when and if this will be able to be secured or accomplished continue to remain uncertain pending conclusion of the adversary proceeding Calpine filed against us on June 29, 2007.

Any failure by Calpine to complete the corrective action necessary to remove title deficiencies with respect to these various properties, including a 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 business, results of operations, financial condition or cash flows 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.

On August 1, 2006, we filed 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 have not presently been determined.

On June 29, 2007, Calpine filed an adversary proceeding against us in the Bankruptcy Court (the "Lawsuit") alleging that the Acquisition was a fraudulent conveyance and seeking to recover either the difference between the amounts it received in the transaction and the reasonably equivalent value of the business conveyed to us or the return of the business we acquired. We have answered and filed affirmative counterclaims against Calpine related to the Acquisition for (i) breach of covenant of solvency, (ii) fraud and fraud in a real estate transaction, (iii) breach of contract, (iv) conversion, (v) civil theft and (vi) setoff. The parties have engaged in an active motion practice in relation to these claims and counterclaims pertaining to the alleged fraudulent conveyance and discovery continues.

On September 11, 2007, the Bankruptcy Court approved the Partial Transfer and Release Agreement ("PTRA") that was executed by Calpine and the Company on August 3, 2007. Under the PTRA, Calpine resolved any title issues in order to allow us to have clear legal title in all offshore properties, certain properties for which the State of California was the lessor, and certain other properties involved in the Acquisition, without prejudice to Calpine's claims and our counterclaims in the pending adversary proceeding. The PTRA did not include all properties that may have legal title issues, such as those properties that required non-governmental, third-party consents or waivers of preferential rights in order to place legal title of the assets in Rosetta's name.

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On December 19, 2007, the Bankruptcy Court approved Calpine's plan of reorganization ("Plan of Reorganization"). Calpine declared January 31, 2008 as the "effective date" for consummation of its Plan of Reorganization and it is the date on which Calpine and certain of its subsidiaries emerged from bankruptcy.

We are continuing to vigorously defend and affirmatively assert our claims in connection with the meritless Lawsuit filed by Calpine.

See Item 3. Legal Proceedings for further information regarding the Calpine bankruptcy, PTRA, and the Lawsuit.

Our Operating Areas

We own producing and non-producing oil and natural gas properties in the Sacramento Basin of California, the Rocky Mountains, the Lobo and Perdido Trends in South Texas, the State Waters of Texas, the Gulf of Mexico, 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, 2007, we have drilled 195 gross and 169 net wells, with a success rate of 82%. 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 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 and to certain properties for which we believe Calpine is obligated to provide further assurances. See Item 3. Legal Proceedings for further information regarding the Calpine bankruptcy.

California-Sacramento Basin

Historically, the Sacramento Basin is one of California's most prolific gas producing areas, containing a majority of the state's largest gas fields. It is conveniently located near the Northern California natural gas markets and has a very robust natural gas gathering and pipeline infrastructure. We are one of the largest producers and leaseholders in the basin.

As of December 31, 2007, we owned approximately 76,000 net acres in the Rio Vista Field and Sacramento Basin areas. Our acreage in the basin holds significant low-risk, low-cost upside potential, and numerous workover and recompletion opportunities. Additional reserve potential exists in gathering system optimization projects, fracture stimulation opportunities in lower permeability, low contrast pays, and deeper gas bearing sands.

For the year ended December 31, 2007, our average net daily production from the Rio Vista Field and surrounding fields in the Sacramento Basin was 44.0 MMcfe/d. In 2007, we drilled 27 gross wells of which 23 were successful. We plan to participate in the drilling of 29 wells in 2008.

Rio Vista Field. The Rio Vista Gas Unit and a significant portion of the deep rights below the Rio Vista Gas Unit, which 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 14 different zones at depths ranging from 2,000 feet to 11,000 feet in the field. The Rio Vista Field trap is a faulted, downthrown rollover anticline, elongated to the northwest. The current productive area is approximately ten miles long and nine miles wide. For the year ended December 31, 2007, the average net daily production in the Rio Vista Field was approximately 40.5 MMcfe/d. We drilled 23 wells in the Rio Vista field in 2007; 20 of these were successful. Six wells drilled in the southern portion of the field were successful in extending areas in two reservoirs, the Lower Capay and the Martinez. This drilling effort was supported by a 12 square mile 3-D seismic program that was shot over the Bradford Island area of the field at the end of 2006. This area of the field had never been covered by 3-D seismic data.

At December 31, 2007, we had one deep rig actively drilling in the field. We secured a second rig at the end of January 2008. We will be procuring a deep rig during the year to drill a deep test under the City of Rio Vista. We plan to participate in the drilling of 20 additional wells in the Rio Vista field in 2008. There are two completion rigs currently working on Rosetta wells in the Rio Vista area. We plan to utilize two to three completion rigs throughout the year. In addition, we plan to conduct between 30 and 40 workover, recompletion or reactivation operations on field wells with these rigs during 2008.

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 Forbes stratigraphic traps on the North side of the Sacramento Basin. Subtle 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 550 square miles of 3-D seismic data and over 1,800 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.

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We drilled four wells in the Sacramento Valley Extension area in 2007, three of these were successful and one was pending completion at year end. Average daily net production for the year ended December 31, 2007 was 3.5 MMcfe/d. We plan to participate in the drilling of 9 additional wells in the Sacramento Valley Extension area in 2008.

Other Activities. We are actively pursuing additional lease and producing property acquisitions throughout the Sacramento Basin. In April 2007, we acquired properties located in the Sacramento Basin from Output Exploration, LLC and OPEX Energy, LLC at a total purchase price of $38.7 million ("OPEX Properties"). The acquisition consisted of 18 producing wells, with net daily production of 3.1 MMcfe/d, and 9.8 BCF of net reserves. We also acquired 4,470 net acres, 112 square miles of 3D seismic and several exploratory prospects in the transaction. The 2008 drilling activity planned for the Sacramento Valley Extension includes five wells that are related to the OPEX Properties, either through our added OPEX acreage or our adjoining acreage, where the improved seismic gained in the OPEX acquisition has helped us identify additional prospects.

Rocky Mountains

At December 31, 2007, we owned approximately 172,000 net acres in the Rocky Mountains. Our production is concentrated in two basins, the DJ and the San Juan Basins. Our average net daily production for the year ended December 31, 2007 was 6.0 MMcfe/d. In 2007, we drilled 89 gross wells of which 75 were successful.

DJ Basin, Colorado. As of December 31, 2007, we had a majority working interest in approximately 109,451 net acres with 125 square miles of 3D seismic data. In 2007, we drilled 70 locations, of which 55 were successful, and identified 49 additional drillable, 3-D seismic supported locations on these lands. To date as of December 31, 2007, we have drilled 134 wells in the developed area of which 114 were successful. For the year ended December 31, 2007, our average net daily production from the DJ Basin was 5.2 MMcfe/d. We have identified over 100 potential drilling locations on our acreage and plan to participate in the drilling of 60 additional wells in 2008 and acquire approximately 29 square miles of additional 3-D seismic data. Pipeline and gathering system construction is expanding in the Republican River, Vernon, SW Wray and Sandy Bluff areas.

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 Bed Methane ("CBM"). There is CBM production from depths of 1,600 feet surrounding our leasehold. As of December 31, 2007, we had a 100% working interest position in approximately 12,000 net acres. In 2007, we drilled 19 CBM wells and one saltwater disposal well with all being successful. For the year ended December 31, 2007, our average net daily production from the San Juan Basin was 0.6 MMcfe/d. We have identified 22 drillable locations on our acreage and plan to participate in the drilling of 14 wells in 2008.

Lobo

Lobo Trend. We are a significant producer in the South Texas, Lobo Trend, with approximately 78,000 net acres, 320 square miles of 3-D seismic and approximately 298 operated producing wells. In 2007 and 2006, we added over 10,000 acres adjacent to our acreage and acquired over 80 square miles of 3-D seismic data adding additional drilling inventory. For the year ended December 31, 2007, our average net daily production from the Lobo Trend was 40.8 MMcfe/d. Our working interests range from 50% - 100% but most of our acreage is 100% owned and operated. We have two drilling rigs under contract which should drill 48 wells in 2008. In 2007, we drilled 42 gross wells of which 33 were successful. We have identified over 100 potential drilling locations on our acreage and plan to participate in the drilling of 48 wells in 2008.

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 trend produces from tight sands with low permeabilities and high pressures at depths from 7,500 to 10,000 feet.

Perdido

Perdido Sand Trend. We own a 50% non-operating working interest in approximately 9,000 net acres in the South Texas, Perdido Sand Trend. The Perdido Sands are comprised of tight natural gas sands and are in isolated fault blocks that are stratigraphically trapped below the Upper Wilcox structures at approximately 8,000 to 9,500 feet. The program of horizontal drilling with fracture stimulations has been very successful in maximizing natural gas recovery. We plan to increase our current acreage position of 9,000 net acres and seismic position of 100 square miles and to continue to coordinate with the operator to improve horizontal drilling techniques to lower cost and increase performance. For the year ended December 31, 2007, our average net daily production was 9.5 MMcfe/d from 42 producing wells (19 horizontal and 23 vertical). We participated in the drilling of ten gross wells in 2007 of which all were successful. We have identified over 50 potential drilling locations on our acreage and plan to participate in the drilling of ten wells in 2008.

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State Waters of Texas

Sabine Lake. We own a 50% operated working interest through a joint venture in Sabine Lake, within Texas State Waters of Jefferson County and Louisiana State Waters of Cameron Parish. During 2007, we drilled four gross wells of which three were successful. Facilities and pipelines were constructed and the wells began producing in November and December of 2007 with a net production rate of 13 MMcfe/d at year-end 2007. We currently hold interest in approximately 6,000 net acres with 70 square miles of 3-D seismic data. We are evaluating additional drilling potential in the region for 2008.

Other Onshore

Live Oak County Prospect. Through the interpretation of 3-D seismic data, we identified and participated in the drilling of a 16,500 foot test in Live Oak County, Texas in the fourth quarter of 2007 and tested the well in December 2007. The well is currently being completed with first production expected in the second quarter of 2008. We have identified further opportunities within an Area of Mutual Interest (“AMI”) agreement covering approximately 22,000 gross acres.

In the Other Onshore region, we currently have approximately 26,000 net acres under lease with an average of a 40% non-operated working interest. In 2007, we drilled 18 gross wells of which 16 were successful and are evaluating additional drilling potential in the region for 2008.

Gulf of Mexico

Federal Waters. We own working interests in 12 offshore blocks ranging from 20% to 100% working interest with approximately 36,000 net acres. For the year ended December 31, 2007, our average net daily production from these blocks was 13 MMcfe/d. Under the PTRA with Calpine, we have its full support and the Bankruptcy Court’s order to secure the outstanding MMS ministerial approval for South Pelto 17 and South Timbalier 252. Due to the absence of production, the MMS leases for East Cameron 76 and South Timbalier 235 have expired.

During 2007, three wells previously drilled and completed in 2006 were placed on production in the first half of 2007, of which we own a 25% - 50% working interest. In 2007, as part of our participation in a joint venture, two wells with a 50% non-operated working interest were drilled, resulting in one dry hole and one well pending completion.

We have entered into an 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.

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, 2007 (1)		
	Natural Gas (Bcf)	Oil (MBbls)	Equivalents (Bcfe)
California	15.9	24.2	16.1
Rocky Mountains	2.2	5.0	2.2
Mid-Continent	0.2	15.4	0.3

Lobo	14.2	113.3	14.9
Perdido	3.4	18.9	3.5
Texas State Waters	0.8	31.7	1.0
Other Onshore	2.3	131.9	2.9
Gulf of Mexico	3.5	220.8	4.9
	42.5	561.2	45.8

(1) Excludes certain interests in leases and wells 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 can not 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, 2007, we had 418.4 Bcfe of proved oil and natural gas reserves, including 400.2 Bcf of natural gas and 3,021 MBbls of oil and condensate. Using prices as of December 31, 2007, the estimated standardized measure of discounted future net cash flows was $954.2 million. The following table sets forth by operating area a summary of our estimated net proved reserve information as of December 31, 2007:

	Estimated Proved Reserves at December 31, 2007 (1)(2)(3)			
	Developed (Bcfe)	Undeveloped (Bcfe)	Total (Bcfe)	Percent of Total Reserves
California	107.5	39.4	146.9	35%
Rocky Mountains	35.6	7.0	42.6	10%
Mid-Continent	1.5	0.5	2.0	0%
Lobo	97.9	57.2	155.1	37%
Perdido	10.6	8.4	19.0	5%
Texas State Waters	10.3	-	10.3	2%
Other Onshore	20.4	2.6	23.0	6%
Gulf of Mexico	17.8	1.7	19.5	5%
Total	301.6	116.8	418.4	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 an estimate of 20 Bcfe of proved oil and natural gas reserves for interests in certain leases and wells being a portion of the properties described in footnote 2 below.

(2) At the July 2005 closing of the Acquisition, we withheld some $75 million for interests in leases and wells (including 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 consents the parties believed at that time were required.

(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 under the Purchase Agreement we believe Calpine is contractually obligated to assist in resolving.

2007 Capital Expenditures

The following table summarizes information regarding development and exploration capital expenditures for the years ended December 31, 2007 and 2006 (Successor), six months ended December 31, 2005 (Successor) and the six months ended June 30, 2005 (Predecessor).

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	Successor			Predecessor
	Year Ended December 31, 2007	Year Ended December 31, 2006	Six Months Ended December 31, 2005	Six Months Ended June 30, 2005
			(In thousands)	
Capital Expenditures by Operating Area:				
California	$ 58,493	$ 39,691	$ 3,933	$ 4,572
Rocky Mountains	23,904	15,299	3,035	1,102
Mid-Continent	4,974	3,371	317	220
Lobo	82,665	51,911	6,775	2,020
Perdido	22,636	25,971	9,268	12,441
Texas State Waters	27,000	13,028	3,023	3,417
Other Onshore	24,822	10,207	10,831	2,300
Gulf of Mexico	28,523	17,958	9,369	4,556
Leasehold	8,838	16,383	9,224	2,617
New acquisitions	38,656	35,105	5,524	-
Delay rentals	1,409	728	143	443
Geological and geophysical/seismic	4,422	3,748	5,659	513
Total capital expenditures (1)	$ 326,342	$ 233,400	$ 67,101	$ 34,201

(1) Capital expenditures for the year ended December 31, 2007 (Successor) excludes capitalized internal costs directly identified with acquisition, exploration and development activities of $5.5 million, capitalized interest of $2.4 million and corporate other capital costs of $1.8 million. Capital expenditures for the year ended December 31, 2006 (Successor) excludes capitalized internal costs of $3.4 million, capitalized interest of $2.1 million and corporate other capital costs of $1.7 million. The six months ended December 31, 2005 (Successor) excludes capitalized interest of $0.6 million, corporate other capital costs of $1.6 million and capitalized internal costs of $1.7 million. Corporate other capital 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.

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, 2007. “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	39,888	32,213	52,547	44,208	179	152
Rocky Mountains	178,393	158,203	18,549	13,525	161	156
Mid-Continent	120	47	9,938	2,575	28	5
Lobo	28,755	31,203	61,949	46,659	248	215
Perdido	14,916	7,385	4,594	2,094	41	20
Texas State Waters	5,706	2,801	10,038	3,193	7	3

Other Onshore	19,689	8,709	44,508	16,905	285	46
Gulf of Mexico (2)	17,495	9,497	46,994	26,886	12	9
	304,962	250,058	249,117	156,045	961	606

(1) This table includes acreage relating to properties for which we believe Calpine is contractually obligated to assist us in resolving, either on the basis of further assurances under the Purchase Agreement and PTRA, or on other legal basis.

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

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The following table shows our interest in undeveloped acreage as of December 31, 2007 which is subject to expiration in 2008, 2009, 2010, and thereafter.

2008		2009		2010		Thereafter	
Gross	Net	Gross	Net	Gross	Net	Gross	Net
36,115	27,229	42,806	35,287	53,309	45,956	172,732	141,586

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.

	Gross Wells					
	Exploratory			Development		
	Productive	Dry	Total	Productive	Dry	Total
2007	11.0	7.0	18.0	149.0	28.0	177.0
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

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
2007	7.5	5.1	12.6	130.2	26.5	156.7
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

Marketing and Customers

Pursuant to our natural gas purchase and sales contract with CES whose term runs through December 2009, we are obligated to sell all of the then-existing and future production from our California leases in production as of May 1, 2005 based on market prices. Calpine maintains a right of first refusal in relation to this dedicated California production for a term of 10 years after December 31, 2009. For the month of December 2007, this dedicated California production comprised approximately 30% 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, provided Calpine has fully cured such payment default, we are obligated under the contract to resume natural gas sales to Calpine. We believe that Calpine's bankruptcy and their emergence from Bankruptcy has not had a 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 purchase and sales contract, to parties other than Calpine, an affiliate of Calpine is under contract through June 30, 2009 to provide us administrative services in connection with such marketing efforts in accordance with the contract terms.

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

Major Customers

For the year ended December 31, 2007, we had one major customer, Calpine Energy Services ("CES"), which accounted on an aggregated basis for approximately 55% of our consolidated annual revenue.

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.

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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. 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.

Government Regulation

The oil and gas industry is subject to extensive laws that are subject to amendment or expansion. These laws have a significant impact on oil and gas exploration, production and marketing activities, and increase the cost of doing business, and consequently, affect profitability. Some of the legislation and regulation affecting the oil and gas industry carry significant penalties for failure to comply. While there can be no assurance that the Company will not incur fines or penalties, we believe we are currently in compliance with the applicable federal, state and local laws. Because enactment of new laws affecting the oil and gas business is common and because existing laws are often amended or reinterpreted, we are unable to predict the future cost or impact of complying with such laws. We do not expect that any of these laws would affect us in a materially different manner than any other similarly sized oil and gas company operating in the United States. The following are significant areas of the laws.

Exploration and Production Regulation

Oil and natural gas production is regulated under a wide range of federal, state and local statutes, rules, orders and regulations, including laws related to location of wells, drilling and casing of wells, well production limitations; spill prevention plans; surface use and restoration; platform, facility and equipment removal; the calculation and disbursement of royalties; the plugging and abandonment of wells; bonding; permits for drilling operations; and production, severance and ad valorem taxes. Oil and gas companies can encounter delays in drilling from the permitting process and requirements. Our operations are subject to regulations governing operation restrictions and 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 prevention of flaring or venting of natural gas. The conservation laws have the effect of limiting 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.

Environmental and Occupation Regulations

We are subject to extensive federal, state and local statutes, rules and regulations concerning protection of the environment and protection of wildlife; restrictions on the emission or discharge of materials into the environment; and occupational safety and health. We have made and will continue to make expenditures in our efforts to comply with these requirements. In this regard, we believe that we currently hold all up-to-date permits, registrations and other authorizations to the extent they are required by our operations under the current regulatory scheme. We maintain insurance at industry customary levels to limit our financial exposure in the event of a substantial environmental claim resulting from sudden, unanticipated and accidental discharges of certain prohibited substances into the environment. Such insurance might not cover the complete amount of such a claim and would not cover fines or penalties for a violation of an environmental law.

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.

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Filings of Reserve Estimates with Other Agencies

We annually file estimates of our oil and gas reserves with the United States Department of Energy ("DOE") for those properties which we operate. During 2007, we filed estimates of our oil and gas reserves as of December 31, 2006 with the DOE, which differ by five percent or less from the reserve data presented in the Annual Report on Form 10-K for the year ended December 31, 2006. For information concerning proved natural gas and crude oil reserves, refer to Item 8. Consolidated Financial Statements and Supplementary Data, Supplemental Oil and Gas Disclosures.

Employees

As of February 18, 2008, we have approximately 152 full time employees. We also contract for the services of independent consultants involved in land, regulatory, accounting, financial, legal 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 website that contains reports, proxy and information statements and other information that is filed electronically with the SEC. The website 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 and certain matters that have survived Calpine's bankruptcy may adversely affect us in several respects.

Calpine, its creditors or interest holders have challenged the fairness of some or all of the Acquisition.

On June 29, 2007, Calpine filed an adversary proceeding against us in the Bankruptcy Court (the "Lawsuit"). The complaint alleges that the purchase by us of the domestic oil and natural gas business formally owned by Calpine (the "Assets") in July 2005 for $1.05 billion, prior to Calpine's declaring bankruptcy, was completed when Calpine was insolvent and was for less than a reasonably equivalent value. Through the Lawsuit, Calpine is seeking (i) monetary damages for the alleged shortfall in value it received for the Assets, which it estimates to be at least approximately $400 million plus interest, or (ii) in the alternative, return of the Assets. We deny and intend to vigorously defend against all claims made by Calpine. The Official Committee of Equity Security Holders and the Official Committee of the Unsecured Creditors both intervened in the Lawsuit for the stated purpose of monitoring the proceedings because these committees claim to have an interest in the Lawsuit, which we dispute because creditors may be paid in full under Calpine's Plan of Reorganization without regard to the Lawsuit and equity holders cannot benefit from fraudulent conveyance actions. On September 10, 2007, we filed a motion to dismiss the complaint, which the Bankruptcy Court heard on October 24, 2007. Following the hearing, the Bankruptcy Court denied our motion on the basis that certain issues we raised in our motion were premature as the bankruptcy process had not yet established how much Calpine's creditors would receive. We filed our answer and counterclaims against Calpine on November 5, 2007. Under Calpine's Plan of Reorganization approved by the Bankruptcy Court on December 19, 2007, the Official Committee of Equity Security Holders was dissolved as of the January 31, 2008 effective date and no longer has any interest in the Lawsuit. While the Unsecured Creditors Committee also officially dissolved as of the same effective date, there are provisions that will allow it to remain involved in lawsuits to which it is a party, which may include this Lawsuit.

The Bankruptcy Court has not set a trial date for the Lawsuit, but the parties are in current agreement that discovery may continue up through April 2008. If after a trial on the merits, the Bankruptcy Court determines that Calpine has met its burden of proof, the Bankruptcy Court could void the transfer or take other actions against us, including (i) setting aside the Acquisition and returning some or all of our purchase price and/or giving us a first lien on all the properties and assets we purchased in the Acquisition or (ii) entering a judgment requiring us to pay Calpine the amount, if any, by which the fair value of the business transferred, as determined by the Bankruptcy Court as of the date of the transaction, exceeded the purchase price determined and paid in July 2005. If the Bankruptcy Court should set aside the Acquisition, it would have a material adverse effect upon our business, results of operations, financial condition or cash flows in that substantially all of the properties received by us 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 have a material adverse effect upon our results of operation and financial condition depending on the amount we might be required to pay. See Item 3. Legal Proceedings for further information regarding the Calpine bankruptcy.

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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.

On June 20, 2007, Calpine filed with the Bankruptcy Court its proposed Plan of Reorganization and disclosure statement. In the disclosure statement, Calpine revealed that it had not yet made a decision on whether to assume or reject its remaining obligations and duties under the Purchase Agreement, including the interrelated agreements, which set forth the terms and agreements related to Calpine's sale of its oil and gas assets to us. In its proposed supplement to the plan filed on the same date, however, Calpine indicated its desire to assume the NAESB agreements under which Rosetta sells gas to Calpine Energy Services ("CES") and the Calpine Producer Services, L.P. ("CPS") marketing agreement under which CPS provides certain marketing services on our behalf. We contend that all of the transaction documents constitute one agreement in regard to the Acquisition and must, therefore, be assumed or rejected in their entirety as one agreement and will vigorously oppose any effort by Calpine to treat any aspect of the transaction documents as a stand-alone agreement. Following negotiations with Calpine with respect to its Plan of Reorganization and its efforts to assume portions of the Purchase Agreement, we agreed to extend the deadline for Calpine to assume or reject the Purchase Agreement with Rosetta related to the transaction until fifteen days following the conclusion of the Lawsuit. In return, Calpine has agreed not to assume or reject the CPS Marketing Agreement or the NAESB agreements until the conclusion of the litigation with Rosetta; however, if Rosetta prevails in the litigation, Calpine has agreed it will assume the Purchase Agreement and all other agreements from the transaction.

Although Calpine had not made its election to assume or reject the Purchase Agreement, on August 3, 2007, we executed a Partial Transfer and Release Agreement ("PTRA") with Calpine, which was approved by the Bankruptcy Court on September 11, 2007, without prejudice to the other pending claims, disputes, and defenses between Calpine and us. As part of the PTRA, we agreed to enter into a new CPS marketing agreement for a period of two years, effective as of July 1, 2007, and concluding on June 30, 2009; however, the marketing agreement is subject to earlier termination by us upon the occurrence of certain events. In return, Calpine has provided documents to resolve legal title issues as to certain previously purchased oil and gas properties located in the Gulf of Mexico, California and Wyoming ("Properties"). Under the PTRA, we have also agreed to assume all liabilities with respect to those Properties, such as plugging and abandonment, as well as all liabilities and rights associated with any under- or over-payment to the State of California as it relates to certain state land.

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 was to be delivered by Calpine to quiet title related to our ownership of these properties following closing. Those properties that may still be subject to ministerial governmental action approving us as qualified assignee and operator were included as part of the Properties being addressed under the PTRA. For certain other properties, the documentation delivered by Calpine at closing was incomplete. Calpine has not made a decision on whether to perform its remaining obligations under the Purchase Agreement with us and thus perform these required further assurances as to title. On October 30, 2007, the California State Lands Commission approved Calpine's assignment of its interests in a certain State of California lease and certain rights-of-way, completing the transfer of those properties to us and resolving open issues on an audit the State had performed on the properties. We are awaiting the final, ministerial approvals from the Mineral Management Service ("MMS") for the assignment of Calpine's interests in those PTRA Properties for which the federal government is the lessor. The PTRA does not otherwise address the Non-Consent Properties which Calpine withheld from the July 2005 closing due to lack of receipt of the lessors' consents determined at that time (in many instances mistakenly) as needed for transfer and for which we withheld from the closing of the transaction with Calpine approximately $75 million of the purchase price. Until the Purchase Agreement is assumed by Calpine, we will not have record title to the interests in the leases and wells specified in the Purchase Agreement as Non-Consent Properties for which Calpine retained an ownership interest.

The bankruptcy proceeding may continue to prevent, frustrate or delay our ability to receive corrective documentation from Calpine for certain properties that we paid for and bought from Calpine, 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 approvals that state we are qualified assignees and operators, 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, all of the same being covered, we believe, by the further assurances provision of the Purchase Agreement, that uncertainty remains pending conclusion of the Lawsuit as to the exact details for each property involved and how, when and if this will be able to be secured or accomplished. As noted above, a number of these open issues were addressed under the PTRA between us and Calpine, and we have obtained or are in the process of obtaining proper legal title as to the PTRA Properties.

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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 (which was granted as to the substantial portion of these leases) 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 business, results of operations, financial position or cash flows 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 by the Calpine bankruptcy from our business and operational matters, our business, results of operations, financial position or cash flows could be materially 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;
- Consumer demand;
- Conservation of resources;
- Regional price differentials and quality differentials of oil and natural gas;

- Domestic and foreign governmental regulations, actions and taxes;
- 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;

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- 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 position, results of operations and cash flows.

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
- Unavailability or high cost of equipment, drilling rigs, supplies or services.

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 financial position, results of operations and cash flows. Calpine's recent emergence from bankruptcy reduces the likelihood of failure, but because we have taken the legal position that any rejection by Calpine of the Purchase Agreement, is also a rejection of the parties' natural gas and sales agreements, this could result in the failure of Calpine to continue purchasing natural gas from us.

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 CES whose term runs through December 2009, we are obligated to sell all of the then-existing and future production from our California leases in production as of May 1, 2005 based on market prices. Calpine maintains a right of first refusal for a term of 10 years after December 31, 2009. For the month of December 2007, this dedicated California production comprised approximately 30% of our current overall production based on an equivalent basis. Additionally, under separate monthly spot agreements, we may sell some of our natural gas production 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, 2007 would be approximately $3.1 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.

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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 will depend on our ability to obtain financing beyond our cash flow from operations. We may 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.

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. Additionally, we have secured a written waiver from our lenders in connection with the Lawsuit based on existing events and our belief concerning those events, and have an ongoing obligation to notify our lenders of all significant developments in the Lawsuit. A more detailed description of our credit facilities is included in Item 7 “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 and obligations associated with the Lawsuit 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 cancelled 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

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- 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 financial position, results of operations and cash flows.

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. As noted above, the estimated reserve quantities and present value calculations exclude the estimates attributable to interests in certain leases and wells being a portion of the Non-Consent Properties specified in the Purchase Agreement. The estimated reserve quantities and present value calculations include properties subject to additional documentation, or completion of documentation, including ministerial actions by federal or state agencies for which we believe Calpine is contractually obligated to assist in resolving, along with certain other leases, concerning which Calpine has asserted an ownership interest under its Section 365 motion and order in the Bankruptcy Court. The estimated reserve quantities and present value calculations may be impacted depending on the outcome of the Lawsuit and whether Calpine assumes or rejects the Purchase Agreement. 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 engineers control. 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. As an example, Netherland Sewell’s reserve report for year end 2007 includes the downward revision for certain proved undeveloped reserves located in South Texas due to the actual production performance history for wells we have drilled in this area since the Acquisition. 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.

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 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. Expense recorded in one period may not be reversed in a subsequent period even though higher natural gas and crude oil prices may have increased the ceiling applicable in the subsequent period.

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For the year ended December 31, 2007, there was no write-down recorded. Due to the volatility of commodity prices, should natural gas prices decline in the future, it is possible that a write-down could occur. See Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations, Critical Accounting Policies and Estimates for further information.

Government laws and regulations can change.

Our activities are subject to federal, state and local laws and regulations. Extensive laws, regulations and rules relate to activities and operations in the oil and gas industry. Some of the laws, regulations and rules contain provisions for significant fines and penalties for non-compliance. Changes in laws and regulations could affect our costs of operations and our profitability. Changes in laws and regulations could also affect production levels, royalty obligations, price levels, environmental requirements, and other matters affecting our business. We are unable to predict changes to existing laws and regulations or additions to laws and regulations. Such changes could significantly impact our business, results of operations, cash flows, financial position and future growth.

Our business requires a sufficient level of staff with technical expertise, specialized knowledge and training and a high degree of management experience.

Our success is largely dependent our ability to attract and retain personnel with the skills and experience required for our business. An inability to sufficiently staff our operations or 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 position, results of operations, cash flows 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 position, results of operations and 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 position, results of operations and 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. Under interruptible or short term transportation agreements, the transportation of our gas may be interrupted due to capacity constraints on the applicable system, for maintenance or repair of the system or for other reasons specified by the particular agreements. 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.

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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.

The unavailability or high cost of drilling rigs, equipment, supplies, personnel and oil field services could adversely affect our ability to execute our exploration and development plans on a timely basis and within our budget.

Our industry is cyclical and, from time to time, there is a shortage of drilling rigs, equipment, supplies or qualified personnel. During these periods, the costs and delivery times of rigs, equipment and supplies are substantially greater. In addition, the demand for, and wage rates of, qualified drilling rig crews rise as the number of active rigs in service increases. As a result of increasing levels of exploration and production in response to strong prices of oil and natural gas, the demand for oilfield services has risen, and the costs of these services are increasing, while the quality of these services may suffer. If the unavailability or high cost of drilling rigs, equipment, supplies or qualified personnel were particularly severe in Texas and California, we could be materially and adversely affected because our operations and properties are concentrated in those areas.

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, financial position, results of operations 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.

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Environmental matters and costs can be significant.

The oil and natural gas business is subject to various federal, state, and local laws and regulations relating to discharge of materials into, and protection of, the environment. Such laws and regulations may impose liability on us for pollution clean-up, remediation, restoration and other liabilities arising from or related to our operations. 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. We also may be liable for environmental damages caused by the previous owners or operators of properties we have purchased or are currently operating. The cost of future compliance is uncertain and is subject to various factors, including future changes to laws and regulations. We have no assurance that future changes in or additions to the environmental laws and regulations will not have a significant impact on our business, results of operations, cash flows, financial condition and future growth.

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 unique 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.

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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.

We have also entered into a series of interest rate swap agreements to hedge the change in the variable interest rates associated with our debt under our credit facility. If interest rates should fall below the rate established in the hedge, we could be exposed to losses associated with these hedges.

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.

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 Agreement to obtain payment from them. We are exposed to the risk that, in these circumstances and in light of the Lawsuit, 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 and the PTRA, 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. In connection with the PTRA, we have submitted the required documents and are waiting for ministerial approvals from the MMS. 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 flows 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.

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 not advised us of any change in the inactive status of the SEC's informal inquiry in this regard. Our understanding is that Calpine 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.

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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, 2007, 50,998,073 shares of common stock were issued, including 899,150 shares of restricted stock issued to certain employees and directors. The majority of these shares vest over a three year period. Of the restricted stock that has been granted, 443,725 shares had vested as of December 31, 2007 and the remaining shares will vest no later than 2012. 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. In addition, we have issued 1,062,600 options to purchase common stock issued to certain employees and directors, of which 90,000 have been exercised as of December 31, 2007. The potential issuance of 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, Rio Vista, California and Magnolia, Arkansas. 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 below in the "Open Issues Regarding Legal Title to Certain Properties" 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 Lawsuit and its possible rejection of the Purchase Agreement may delay or frustrate our ability to complete additional transfers of properties for which legal title was not obtained or secure curative documentation to correct possible clouds on title as of July 7, 2005. See item 3. Legal Proceedings for further information concerning the Lawsuit and Calpine's possible rejection of the Purchase Agreement, and the effect of possible losses in connection with open issues regarding legal title to certain properties.

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 consolidated financial statements.

Calpine Bankruptcy

On December 20, 2005, Calpine 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 19, 2007, the Bankruptcy Court approved Calpine's Plan of Reorganization. On January 31, 2008, Calpine and certain of its subsidiaries emerged from Bankruptcy.

Calpine's Lawsuit Against Rosetta

On June 29, 2007, Calpine filed an adversary proceeding against us in the Bankruptcy Court (the "Lawsuit"). The complaint alleges that the purchase by Rosetta of the domestic oil and natural gas business owned by Calpine (the "Assets") in July 2005 for $1.05 billion, prior to Calpine filing for bankruptcy, was completed when Calpine was insolvent and was for less than a reasonably equivalent value. Through the Lawsuit, Calpine is seeking (i) monetary damages for the alleged shortfall in value it received for these Assets which it estimates to be at least approximately $400 million plus interest, or (ii) in the alternative, return of the Assets from us. We believe that the allegations in the Lawsuit are without merit, and we continue to believe that it is unlikely that this challenge by Calpine to the fairness of the Acquisition will be successful upon the ultimate disposition of this litigation in the Bankruptcy Court, or if necessary, in the appellate courts. The Official Committee of Equity Security Holders and the Official Committee of the Unsecured Creditors both intervened in the Lawsuit for the stated purpose of monitoring the proceedings because the committees claimed to have an interest in the Lawsuit, which we dispute because we believe creditors may be paid in full under Calpine's Plan of Reorganization without regard to the Lawsuit and equity holders have no interest in fraudulent conveyance actions. Under Calpine's Plan of Reorganization approved by the Bankruptcy Court on December 19, 2007, the Official Committee of Equity Security Holders was dissolved as of the January 31, 2008 effective date and no longer has any interest in the Lawsuit. While the Unsecured Creditors Committee also was officially dissolved as of the same effective date, there are provisions under the approved Plan of Reorganization that will allow it to remain involved in lawsuits to which it is a party, which may include this Lawsuit.

On September 10, 2007, we filed a motion to dismiss the Lawsuit or in the alternative, to stay the Lawsuit. The Bankruptcy Court conducted a hearing upon our motion on October 24, 2007. Following the hearing, the Bankruptcy Court denied our motion on the basis that certain issues we raised in our motion were premature as the bankruptcy process had not yet established how much Calpine's creditors would receive. On November 5, 2007, we filed our answer, affirmative defenses and counterclaims with respect to the Lawsuit, denying the allegations set forth in both counts of the Lawsuit, and asserting affirmative defenses to Calpine's claims as well as affirmative counterclaims against Calpine related to the Acquisition for (i) breach of covenant of solvency, (ii) fraud and fraud in a real estate transaction, (iii) breach of contract, (iv) conversion, (v) civil theft and (vi) setoff. The parties are currently in agreement that discovery may continue in the Lawsuit until April 2008. The Bankruptcy Court has not set a trial date for the lawsuit.

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Remaining Issues with Respect to the Acquisition

Separate from the Calpine lawsuit, Calpine has taken the position that the Purchase and Sale Agreement and interrelated agreements concurrently executed therewith, dated July 7, 2005, by and among Calpine, us, and various other signatories thereto (collectively, the “Purchase Agreement”) are “executory contracts”, which Calpine may assume or reject. Following the July 7, 2005 closing of the Acquisition and as of the date of Calpine’s bankruptcy filing, there were open issues regarding legal title to certain properties included in the Purchase Agreement. On September 25, 2007, the Bankruptcy Court approved Calpine’s Disclosure Statement accompanying its proposed Plan of Reorganization under Chapter 11 of the Bankruptcy Code, in which Calpine revealed it had not yet made a decision as to whether to assume or reject its remaining duties and obligations under the Purchase Agreement. We may contend that the Purchase Agreement is not an executory contract which Calpine may choose to reject. If the Court were to determine that the Purchase Agreement is an executory contract, we may contend the various agreements entered into as part of the transaction constitute a single contract for purposes of assumption or rejection under the Bankruptcy Code, and we may argue that Calpine cannot choose to assume certain of the agreements and to reject others. This issue may be contested by Calpine. If the Purchase Agreement is held to be executory, the deadline by when Calpine must exercise its decision to assume or reject the Purchase Agreement and the further duties and obligations required therein would normally have been the date on which Calpine’s Plan of Reorganization was confirmed; however, in order to address certain issues, we and Calpine have agreed to extend this deadline until fifteen days following the entry of a final, unappealable order in the Lawsuit, and the parties set forth this agreement in the proposed Plan of Reorganization approved by the Bankruptcy Court on December 19, 2007.

Open Issues Regarding Legal Title to Certain Properties

Under the Purchase Agreement, Calpine is required to resolve the open issues regarding legal title to interests in certain properties. At the closing of the Acquisition on July 7, 2005, we retained approximately $75 million of the purchase price in respect to leases and wells identified by Calpine as requiring third-party consents or waivers of preferential rights to purchase that were not received by the parties before closing (“Non-Consent Properties”). The interests in the Non-Consent Properties were not included in the conveyances delivered at the closing. Subsequent analysis determined that a significant portion of the Non-Consent Properties did not require consents or waivers. For that portion of the Non-Consent Properties for which third-party consents were in fact required and for which either us or Calpine obtained the required consents or waivers, as well as for all Non-Consent Properties that did not require consents or waivers, we contend Calpine was and is obligated to have transferred to us the record 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 the third-party preferential right, 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, if necessary, will be transferred to the appropriate third party under its exercised preferential purchase right upon Calpine’s performance of its 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 subject to the third-party preferential right) were satisfied earlier, and certainly no later, than December 15, 2005, when we tendered 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 the record title and that such properties are not part of Calpine’s bankruptcy estate. Upon our receipt from Calpine of record title, free of any mortgages or other liens, to these Non-Consent Properties (excluding that portion of these properties subject to a validly exercised third party's preferential right to purchase) and further assurances required to eliminate any open issues on title to the remaining properties discussed below, we have been prepared to conclude the remaining aspects of the Acquisition. We have not included in our statement of operations for the years ended December 31, 2007 and 2006 and six months ended December 31, 2005, estimated net revenues and related estimated production from interests in certain leases and wells being a portion of the Non-Consent Properties, including those properties subject to preferential rights.

On September 11, 2007, the Bankruptcy Court entered an order approving that certain Partial Transfer and Release Agreement ("PTRA") negotiated by and between us and Calpine which, among other things, resolves issues in regard to title of certain of the other oil and natural gas properties we purchased from Calpine in the Acquisition and for which payment was made to Calpine on July 7, 2005, and we entered into a new Marketing and Services Agreement ("MSA") with Calpine Producer Services, L.P. ("CPS") for a two-year period commencing on July 1, 2007 but which is subject to earlier termination by us on the occurrence of certain events. The additional documentation received from Calpine under the PTRA eliminates any open issues in our title and resolves any issues as to the clarity of our ownership in certain properties located in the Gulf of Mexico, California, and Wyoming (the "PTRA Properties"), including all oil and gas properties requiring ministerial approvals, such as leases with the U.S. Minerals Management Service ("MMS"), California State Lands Commission ("CSLC") and U.S. Bureau of Land Management ("BLM"). However, the PTRA was executed without prejudice to Calpine's fraudulent conveyance action or its right, if any, to reject the Purchase Agreement, and without prejudice to our rights and legal arguments in relation thereto, including our various counterclaims. The PTRA did not otherwise address or resolve issues with respect to the Non-Consent Properties and certain other properties.

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We recorded the conveyances of those PTRA Properties in California not requiring governmental agency approval. On October 30, 2007, the CSLC approved the assignment of the State of California leases and rights of way to us from Calpine and resolved open issues under an audit the State of California had conducted as to these properties. While the documentation has been filed with the MMS, we are still awaiting its ministerial approval for the assignment of Calpine's interests in MMS Federal Offshore leases for South Pelto 17 and South Timalier 252 to us.

Notwithstanding the PTRA, as a result of Calpine's bankruptcy filing, it remains uncertain as to whether Calpine will respond cooperatively as to the remaining outstanding issues under the Purchase Agreement. If Calpine does not fulfill its contractual obligations (as a result of rejection of the Purchase Agreement or otherwise) and does not complete the documentation necessary to resolve these remaining issues whether under the Purchase Agreement or the PTRA, 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 unlikely upon ultimate disposition, including appeals, if any, then we could experience losses which could have a material adverse effect on our business, financial condition, statement of operations or cash flows.

Sale of Natural Gas to Calpine

In addition to the issues involving legal title to certain properties, we executed, as part of the interrelated agreements that constitute the Purchase Agreement, certain natural gas sales agreements with Calpine Energy Services, L.P. ("CES"), which also filed for bankruptcy on December 20, 2005. During the period following Calpine's filing for bankruptcy, CES has continued to make the required deposits into our margin account and to timely pay for natural gas production it purchases from our subsidiaries under these various natural gas sales agreements. Although Calpine has indicated in a supplement to its recently proposed Plan of Reorganization that it intends to assume the CES natural gas sales agreements with us, we disagree that Calpine may assume anything less than the entire Purchase Agreement and intend to oppose any effort by Calpine to do less.

Calpine's Marketing of the Company's Production

As part of the PTRA, we entered into the MSA with CPS, effective July 1, 2007, which was approved by the Bankruptcy Court on September 11, 2007. Under the MSA, CPS provides marketing and related services in relation to the sales of our natural gas production and charges us a fee. This MSA extends CPS' obligations to provide such services until June 30, 2009. The MSA is subject to early termination by us upon the occurrence of certain events.

Events within Calpine's Bankruptcy Case

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 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. The oil and gas leases identified in Calpine's motion are, in large part, those properties with open issues in regards to their legal title in certain oil and natural gas leases which Calpine contends it may possess some legal interest. According to this motion, Calpine filed its pending bankruptcy proceeding in order to avoid the automatic forfeiture of any interest it may have in these leases by operation of a bankruptcy code deadline. Calpine's motion did not request that the Bankruptcy Court determine whether these properties belong to us or Calpine, but we understand Calpine's motion 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 the our rights and interest in and to the leases. Certain of these properties have been subsequently addressed under the PTRA discussed above.

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 MMS has subsequently recognized us as owner and operator of all but two of these properties, two other leases of offshore properties having expired, 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 could seek mediation to complete the following:

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- Calpine's conveyance of its retained interest in 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.

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 CSLC 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 MMS) (the "MMS Oil and Gas Leases") and the State of California (and managed by the CSLC) (the "CSLC Leases"). Calpine, 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 (excluding the properties subject to third party's preferential right).

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 have not presently been determined. In the event that Calpine elects to reject the Purchase Agreement or otherwise refuses to perform its remaining obligations therein, we anticipate we will be allowed to amend our proofs of claim to assert any additional damages we suffer as a result of the ultimate impact of Calpine's refusal or failure to perform under the Purchase Agreement. In the bankruptcy, Calpine may elect to contest or dispute the amount of damages we seek in our proofs of claim. We will assert all right to offset any of our damages against any funds we possess that may be owed to Calpine. Until the allowed amount of our claims are finally established and the Bankruptcy Court issues its rulings with respect to Calpine's approved Plan of Reorganization, we can not predict what amounts we may recover from the Calpine bankruptcy should Calpine reject or refuse to perform 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 and the CSLC Leases respectively, these parties further extended this deadline by stipulation. The deadline was first extended to January 31, 2007, 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, was further extended again to September 15, 2007 with respect to the MMS Oil and Gas Leases and July 15, 2007 and more recently, October 31, 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. The MMS Oil and Gas Leases and CSLC Leases were included in the PTRA that was approved by the Bankruptcy Court on September 11, 2007, with the result that there is no further need for the parties to contest whether the MMS Oil and Gas Leases and the CLSC Leases are appropriate for inclusion in Calpine's 365 motion. The PTRA approved by the Bankruptcy Court, among other things, resolves open issues in regard to our title to ownership of all of the unexpired MMS Oil and Gas Leases and the CLSC Leases. However, the PTRA was executed without prejudice to Calpine's fraudulent conveyance action or its rights, if any, to reject the Purchase Agreement and our rights and legal arguments in relation thereto.

On June 20, 2007, Calpine filed its proposed Plan of Reorganization and Disclosure Statement with the Bankruptcy Court. Calpine had indicated in its filings with the Court that it believed substantial payments in the form of cash or newly issued stock, or some combination thereof, would be made to unsecured creditors under its proposed Plan of Reorganization that could conceivably result in payment of 100% of allowed claims and possibly provide some payment to its equity holders. The amounts any plan ultimately distributes to its various claimants of the Calpine estate, including unsecured creditors, will depend on the amount of allowed claims that remain following the objection process. The Bankruptcy Court approved Calpine's Plan of Reorganization on December 19, 2007, overruling our objection to the releases granted by this Plan to prior and current directors and officers of Calpine and certain of its law firms and other professional advisors.

On August 3, 2007, we executed the PTRA, resolving certain open issues without prejudice to Calpine's avoidance action and, if the Court concludes the Purchase Agreement is executory, Calpine's ability to assume or reject the Purchase Agreement. The principal terms are as follows:

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- We entered into a new MSA with CPS through and until June 30, 2009, effective July 1, 2007. This agreement is subject to earlier termination right by us upon the occurrence of certain events;

- Calpine delivers to us documents that resolve title issues pertaining to the Properties defined as certain previously purchased oil and gas properties located in the Gulf of Mexico, California and Wyoming;

- We assume all Calpine's rights and obligations for an audit by the California State Lands Commission on part of the Properties; and

- We assume all rights and obligations for the Properties, including all plugging and abandonment liabilities.

On September 11, 2007, the Bankruptcy Court approved the PTRA. The PTRA did not resolve the open issues on the Non-Consent Properties and certain other properties.

Notwithstanding the PTRA, as a result of Calpine's bankruptcy, there remains the possibility that there will be issues between us and Calpine that could amount to material contingencies in relation to the litigation filed by Calpine against us or 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 PTRA; and (iii) the issues pertaining to the Non-Consent Properties.

Arbitration between Calpine/Rosetta 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 that 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. With Rosetta's assistance, 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 had earlier declined to accept the Company's tender of defense and indemnity when Pogo filed for arbitration against us. We filed a motion to stay this arbitration under the automatic stay provision of the Bankruptcy Code which motion was granted by the Bankruptcy Court on April 24, 2007. We intend to cooperate with Calpine in defending against Pogo's claim should it resume; however, it is too early for management to determine whether this matter will affect us, and if so, in what amount. This is due, but not limited to uncertainity concerning (1) whether or not Pogo's proofs of claim will be fully satisfied by Calpine under its approved Plan of Reorganization; and (2) whether and if so, the extent to which, Calpine may reimburse us for our claim for our defense costs and any arbitration award regarding the Pogo claim.

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 2007.

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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 2007 and 2006 periods indicated the high and low sale prices of our common stock:

2007	High	Low	2006	High	Low
January 1 - March 31	$ 21.07	$ 17.66	February 13 - March 31	$ 18.75	$ 17.67
April 1 - June 30	25.00	20.74	April 1 - June 30	21.48	15.81
July 1 - September 30	21.97	15.67	July 1 - September 30	19.05	15.82
October 1 - December 31	20.84	17.69	October 1 - December 31	19.89	16.71

The number of shareholders of record on February 18, 2008 was 10,912. 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, 2007:

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	1,404	$ 18.60	-	-
November 1 - November 30	2,381	18.49	-	-
December 1 - December 31	82	17.93	-	-

(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 stock performance 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 (“HK”), St. Mary Land & Exploration Co. (“SM”), Bill Barrrett Corp. (“BBG”), Brigham Exploration Co. (“BEXP”), Berry Petroleum Co. (“BRY”), Comstock Resources Inc. (“CRK”) and Range Resources Corp. (“RRC”), all known as our peer group (“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.

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

	2/13/2006 (1)	12/31/2006	12/31/2007
ROSE	$ 100.00	$ 98.26	$ 104.37
S&P 500 Index	$ 100.00	$ 111.94	$ 115.89
Peer Group	$ 100.00	$ 94.82	$ 128.62

(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.

Item 6. Selected Financial Data

The following table sets forth our selected financial data. For the years ended December 31, 2007 and 2006 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 and for the years ended December 31, 2004 and 2003 (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, Statement of Financial Accounting Standards ("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,		Six Months Ended December 31,	Six Months Ended June 30,	Year Ended December 31,	
	2007	2006	2005	2005	2004 (1)	2003 (1)
	(In thousands, except per share data)					
Operating Data:						
Total revenue	$ 363,489	$ 271,763	$ 113,104	$ 103,831	$ 248,006	$ 279,916
Income (loss) from continuing operations (2)	57,205	44,608	17,535	18,681	(78,836)	66,879
Net income (loss) (2)	57,205	44,608	17,535	18,681	(10,396)	71,440
Income per share (2):						
Income (loss) from continuing operations						
Basic	1.14	0.89	0.35	0.37	(1.58)	1.34
Diluted	1.13	0.88	0.35	0.37	(1.58)	1.33
Net income (loss)						
Basic	1.14	0.89	0.35	0.37	(0.21)	1.43
Diluted	1.13	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	1,357,214	1,219,405	1,119,269	-	656,528	990,893
Long-term debt	245,000	240,000	240,000	-	-	507
Stockholders' equity/owner's net investment	872,955	822,289	715,423	-	223,451	233,847

(1) 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 the respective periods presented herein.

(2) Includes a $202.1 million pre-tax 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 Rocky Mountains, the Lobo and Perdido Trends in South Texas, the State Waters of Texas and the Gulf of Mexico 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 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. In addition, we have also entered into a series of interest rate swap agreements to hedge the change in variable interest rates associated with our debt under our credit facility. In periods where interest rates rise, these hedges will mitigate losses to future earnings. In periods of falling interest rates, these hedges will expose us to losses in future earnings.

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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 on adding reserves through drilling and acquisitions, while placing a clear priority on lowering the Company's cost of replacing reserves. Consistent with our stated strategies, we will emphasize building a high-quality inventory of future drilling projects while also focusing on improving our capital and cost efficiency. We have several efforts underway to address this challenge.

We have set a goal to fully assess our existing asset portfolio during 2008. We will implement a formal capital performance lookback process to monitor where value is being created. In addition, we will form technical teams to study the resource potential of our current assets, many of which we believe may yield significant future drilling inventory through down-spacing programs, deeper or shallower programs or close extensions. The combination of more inventory and calibration on our programs from the lookback exercise should allow us to deliver better performance on our future capital spending.

We also expect to launch several of significant resource assessments in basins, trends, or plays where significant inventory can be identified. We are considering several areas where we have technical expertise that could be applied to new or extension opportunities. This effort will service existing asset optimization as well as our merger and acquisition efforts.

Finally, we will undertake to improve our capital and cost efficiency on an ongoing business. We will look for opportunities to attract additional experienced personnel with successful track records, streamline or improve processes and organize for profitable growth. In addition to the capital lookback process, we expect to bolster several other core analytic functions, including reserve engineering, business analysis and planning.

Financial Highlights

Our consolidated financial statements reflect total revenue of $363.5 million on total volumes of 45.8 Bcfe for the year ended December 31, 2007 (Successor). Operating income was $106.6 million, or 29% of total revenue, and included lease operating expense of $47.0 million and $6.8 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 long-term debt offset by interest income on short term cash investments. Overall, our net income for the year ended December 31, 2007 (Successor) was $57.2 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 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 certain 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. 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.

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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. As all of our operations are located in the U.S., all of our costs are included in one cost pool. 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 directly relate to our oil and gas activities. Interest costs related to unproved properties are also capitalized. 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, 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.

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 Netherland Sewell 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. For more information regarding reserve estimation, including historical reserve revisions, refer to Item 8. Consolidated Financial Statements and Supplementary Data, Supplemental Oil and Gas Disclosures.

Full Cost Ceiling Limitation

Our ceiling test computation was calculated using hedge adjusted market prices at December 31, 2007, which were based on a Henry Hub price of $6.80 per MMBtu and a West Texas Intermediate oil price of $92.50 per Bbl (adjusted for basis and quality differentials). The use of these prices would have resulted a pre-tax writedown of $21.5 million at December 31, 2007. However, we reevaluated our ceiling test exposure on February 22, 2008 using the market price for Henry Hub of $8.91 per MMBtu and the price for West Texas Intermediate $98.88 per Bbl. Utilizing these prices, the calculated ceiling amount exceeded our net capitalized cost of oil and gas properties. As a result, no write-down was recorded for the year ended December 31, 2007. Due to the volatility of commodity prices, should natural gas prices decline in the future, it is possible that a write-down could occur.

There was no ceiling test write-down for the year ended December 31, 2006 or for the six months ended December 31, 2005.

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 depletion 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 (“DD&A”) rate by approximately $0.18 to $0.19 per MMcfe. This estimated impact is based on current data at December 31, 2007 and actual events could require different adjustments to DD&A.

Derivative Transactions and Hedging Activities

We enter into derivative transactions to hedge against changes in oil and natural gas prices and changes in interest rates related to outstanding debt under our credit agreements primarily through the use of fixed price swap agreements, basis swap agreements, costless collars and put options. Consistent with our hedge policy, we entered into a series of derivative transactions to hedge a significant portion of our expected natural gas production through 2009. We also entered into a series of interest rate swap agreements to hedge the change in interest rates associated with our variable rate debt through June of 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 changes in interest rates 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).

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 and such costs are included in the calculation of DD&A expense. 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 the property's 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.

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 DD&A expense. Likewise, if these estimates are revised downward, earnings would increase due to lower DD&A expense.

Stock -Based Compensation

We account for stock-based compensation in accordance with SFAS 123R. Under the provisions of SFAS 123R, stock-based compensation cost is estimated at the grant date based on the award's fair value as calculated by the

Black-Scholes option-pricing model and is recognized as expense over the requisite service period. The Black-Scholes model requires various highly judgmental assumptions including volatility, forfeiture rates and expected option life. If any of the assumptions used in the Black-Scholes model change significantly, stock-based compensation expense may differ materially in the future from that recorded in the current period.

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, 2007 and 2006, imbalances were insignificant.

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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, natural gas liquids and crude oil 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. 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.

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. Consolidated Financial Statements and Supplementary Data, Note 13 Income Taxes.

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 $1.0 million for the year ended December 31, 2007.

FASB Interpretation No. 48, "Accounting for Uncertainty in Income Taxes - an interpretation of FASB Statement No. 109" ("FIN 48") requires that we recognize the financial statement benefit of a tax position only after determining that the relevant tax authority would more likely than not sustain the position following an audit. For tax positions meeting the more likely than not threshold, the amount recognized in the financial statements is the largest benefit that has a greater than 50% likelihood of being realized upon ultimate settlement with the relevant tax authority.

Recent Accounting Developments

Noncontrolling Interests in Consolidated Financial Statements. In December 2007, the Financial Accounting Standards Board ("FASB") issued SFAS No. 160, "Noncontrolling Interests in Consolidated Financial Statements, an amendment of Accounting Research Bulletin No. 51" (SFAS No. 160), which improves the relevance, comparability and transparency of the financial information that a reporting entity provides in its consolidated financial statements by establishing accounting and reporting standards for the noncontrolling interest in a subsidiary and for the deconsolidation of a subsidiary. This statement is effective for fiscal years beginning after December 15, 2008. We do not expect the adoption of SFAS No. 160 to have a material impact on our consolidated financial position, results of operations or cash flows.

Business Combinations. In December 2007, FASB issued SFAS No. 141(R), "Business Combinations" ("SFAS No. 141R"), which creates greater consistency in the accounting and financial reporting of business combinations. This statement is effective for fiscal years beginning after December 15, 2008. We do not expect the adoption of SFAS No. 141R to have a material impact on the our consolidated financial position, results of operations or cash flows.

The Fair Value Option for Financial Assets and Financial Liabilities. In February 2007, 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. We do not expect the adoption of SFAS No. 159 to have a material impact on our consolidated financial position, results of operations or cash flows as we did not choose to measure at fair value.

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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 FASB has also issued Staff Position FAS 157-2 ("FSP No. 157-2"), which delays the effective date of SFAS No. 157 for nonfinancial assets and liabilities, except for items that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually), until fiscal years beginning after November 15, 2008. We do not expect the adoption of SFAS No. 157 or FSP No. 157-2 to have a material impact on our consolidated financial position, results of operations or cash flows.

Results of Operations

The following table summarizes our results of operations and compares the year ended December 31, 2007 to the year ended December 31, 2006. However, 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. 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.

Differences in accounting principles also exist between Calpine and us, 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 for the year ended December 31, 2006 and 2005; therefore, we have presented the information below separately as Successor and Predecessor. In addition, at the closing of the Acquisition on July 7, 2005, we retained approximately $75 million of the purchase price in respect to interest in leases and wells associated with the Non-Consent Properties. Our operating income does not include our estimated revenues and expenses related to certain interests in leases and wells being a portion of the Non-Consent Properties, which were a part of the Predecessor's operating income.

	Successor-Consolidated			Predecessor-Combined
	Year Ended December 31, 2007	Year Ended December 31, 2006	Six Months Ended December 31, 2005	Six Months Ended June 30, 2005
Total revenues (In thousands)	$ 363,489	$ 271,763	$ 113,104	$ 103,831
Production:				
Gas (Bcf)	42.5	30.3	12.4	14.5
Oil (MBbls)	561.2	551.3	185.6	163.8
Total Equivalents (Bcfe)	45.8	33.4	13.5	15.5
$ per unit:				
Avg. Gas Price per Mcf	$ 7.61	$ 7.81	$ 8.23	$ 6.59

Avg. Gas Price per Mcf excluding Hedging	7.07	6.83	9.57	-
Avg. Oil Price per Bbl	71.54	64.01	59.52	49.86
Avg. Revenue per Mcfe	$ 7.94	$ 8.14	$ 8.38	$ 6.70

Revenues

Our revenues are derived from the sale of our oil and natural gas production, which includes the effects of qualifying commodity hedge contracts. Our revenues may vary significantly from period to period as a result of changes in commodity prices or volumes of production sold.

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Year Ended December 31, 2007 (Successor) Compared to the Year Ended December 31, 2006 (Successor)

Total revenue for the year ended December 31, 2007 was $363.5 million which is an increase of $91.7 million, or 34%, from the year ended December 31, 2006. Approximately 89% of revenue was attributable to natural gas sales on total volumes of 45.8 Bcfe.

Natural Gas. For the year ended December 31, 2007, natural gas revenue increased by $86.8 million, including the realized impact of derivative instruments, from the comparable period in 2006, to $323.3 million. The increase is primarily attributable to California and Lobo production of 15.9 Bcfe and 14.2 Bcfe, respectively, or 78% of the increased production. This increase is primarily due to an increase in the number of wells producing in 2007 as compared to 2006, which includes the acquisition of the OPEX properties in the second quarter of 2007. The effect of gas hedging activities on natural gas revenue for the year ended December 31, 2007 was a gain of $22.9 million as compared to a gain of $29.6 million for the year ended December 31, 2006. The average realized natural gas price including the effects of hedging decreased from $7.61 per Mcf for the year ended December 31, 2007 as compared to the same period in 2006 of $7.81 per Mcf.

Crude Oil. For the year ended December 31, 2007, oil revenue increased by $4.9 million primarily due to the increase in the average oil price of $7.53 per Bbl from $64.01 per Bbl for the year ended December 31, 2006 as compared to $71.54 for the year ended December 31, 2007. The slight increase in oil production volumes were associated with increased production in California, Lobo and Texas State Water regions due to the new wells in 2007.

Year Ended December 31, 2006 (Successor)

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 including the effects of hedging. 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.

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 an 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.

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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

Operating Expenses

The following table presents information about our operating expenses:

	Successor-Consolidated			Predecessor-Combined
	Year Ended December 31, 2007	Year Ended December 31, 2006	Six Months Ended December 31, 2005	Six Months Ended June 30, 2005
	(In thousands, except per unit amounts)			
Lease operating expense	$ 47,044	$ 36,273	$ 15,674	$ 16,629
Depreciation, depletion and amortization	152,882	105,886	40,500	30,679
Production taxes	6,417	6,433	3,975	2,755
General and administrative costs	$ 43,867	$ 33,233	$ 14,687	$ 9,677
$ per unit:				
Avg. lease operating expense per Mcfe	$ 1.03	$ 1.09	$ 1.16	$ 1.08
Avg. DD&A per Mcfe	3.34	3.17	3.00	1.98
Avg. production taxes per Mcfe	0.14	0.19	0.29	0.18
Avg. G&A per Mcfe	$ 0.96	$ 1.00	$ 1.09	$ 0.63

Year Ended December 31, 2007 Compared to the Year Ended December 31, 2006 (Successor)

Lease Operating Expense. Lease operating expense increased $10.8 million for the year ended December 31, 2007 as compared to the same period for 2006. This overall increase is primarily due the increase in production of 37% for 2007 which led to higher costs for equipment rentals, maintenance and repairs, and costs associated with non-operated properties. In addition, there was an increase of $5.2 million in ad valorem taxes primarily related to property appraisals in California. The overall increase was offset by a $1.6 million decrease in workover expense primarily due to the insurance reimbursement in 2007 of $2.4 million for claims submitted as a result of Hurricane Rita. Lease operating expense includes workover costs of $0.11 per Mcfe, ad valorem taxes of $0.26 per Mcfe and insurance of $0.05 per Mcfe for the year ended December 31, 2007 as compared to workover costs of $0.19 per Mcfe, ad valorem taxes of $0.20 and insurance of $0.04 per Mcfe for the same period in 2006.

Depreciation, Depletion, and Amortization. Depreciation, depletion and amortization expense increased $47.0 million for the year ended December 31, 2007 as compared to the same period for 2006. The increase is due to a 37% increase in total production and a higher DD&A rate for 2007 as compared to 2006. The DD&A rate for the respective period in 2007 was $3.34 per Mcfe while the rate for the same period in 2006 was $3.17 per Mcfe due to the increase in finding costs.

Production Taxes. Production taxes as a percentage of oil and natural gas sales were 1.8% for the year ended December 31, 2007 as compared to 2.4% for the year ended December 31, 2006. This decrease is the result of increased tax credits received for the year ended December 31, 2007 as compared to the same period for 2006. The tax credits were received for natural gas wells drilled in qualifying formations primarily in the Lobo and Perdido regions.

General and Administrative Costs. General and administrative costs, net of capitalized general and administrative costs of $5.5 million for the year ended December 31, 2007, increased by $10.6 million for the year ended December 31, 2007 as compared to the same period for 2006, with capitalized general and administrative costs of $3.5 million. This increase is net of decreases in audit and consulting fees related to higher costs in the first six months of 2006 associated with becoming a public company, which was not incurred in 2007. The increase in costs incurred in the current period are primarily related to increases in the CEO transition costs of approximately $5.0 million, increases in legal fees related to the Calpine litigation of $2.6 million and increases in payroll expenses associated with the payout of bonuses of $2.9 million. The increase is also associated with stock-based compensation, which increased $1.1 million from $5.7 million for the year ended December 31, 2006 to $6.8 million for the year ended December 31, 2007.

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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 DD&A rate was $3.17 per Mcfe. There were no ceiling test write-downs for the year ended December 31, 2006.

Production Taxes. Production taxes as a percentage of natural gas and oil sales were approximately 2.4% for the year ended December 31, 2006. Production taxes were primarily based on the wellhead values of production and vary across the different regions.

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 DD&A 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.

Production Taxes. Production taxes as a percentage of natural gas and oil sales were approximately 3.6% for the six months ended December 31, 2005. Production taxes were primarily based on the wellhead values of production and vary across the different regions.

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 DD&A rate was $1.98 per Mcfe for the six months ended June 30, 2005.

Production Taxes. Production taxes as a percentage of natural gas and oil sales were approximately 2.7% for the six months ended December 31, 2005. Production taxes were primarily based on the wellhead values of production and vary across the different regions.

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.

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Total Other Expense

Other expense includes interest expense, interest income and other income/expense, net which increased $2.5 million for the year ended December 31, 2007 (Successor) as compared to the respective period in 2006. The increase in other expense is the result of reduced interest income in 2007 to offset interest expense as compared to 2006. The interest income is earned on the cash balances, which were greater during 2006 than in 2007. Approximately $35.3 million was expended during the fourth quarter of 2006 to fund various asset acquisitions and approximately $38.7 million was expended during the second quarter of 2007 for the acquisition of the OPEX Properties.

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 Revolver 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 (Predecessor), other expense of $7.0 million was associated with the intercompany debt with Calpine Corporation.

Provision for Income Taxes

For the year ended December 31, 2007(Successor), the effective tax rate was 37.3% as compared to the effective tax rate of 38.3% for the year ended December 31, 2006 (Successor). For the six months ended December 31, 2005 (Successor), the effective tax rate was 39.7% and for the six months ended June 30, 2005 (Predecessor), the effective tax rate was 38.1%. The provision for income taxes differs from the taxes computed at the federal statutory income tax rate primarily due to the effect of state taxes.

Liquidity and Capital Resources

Our primary source of liquidity and capital is our operating cash flow. We also maintain a revolving line of credit, which can be accessed as needed to supplement operating cash flow.

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 in which our derivative transactions are in place. The effects of these derivative transactions on our natural gas sales are discussed above under "Results of Operations – Natural Gas". In addition, the majority of our capital expenditures are discretionary and could be curtailed if our cash flows decline from expected levels.

Senior Secured Revolving Line of Credit. In July 2005, BNP Paribas 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. In July 2005, we repaid $60.0 million of the $225.0 million in original borrowings on the Revolver. In addition, in 2007, we increased our net borrowings against the Revolver by $5.0 million, bringing the balance to $170.0 million at December 31, 2007. 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. In May 2007, the borrowing base was adjusted to $350.0 million. Initial amounts outstanding under the Revolver bore interest, as amended, at specified margins over the London Interbank Offered Rate ("LIBOR") of 1.25% to 2.00% (5.82% at December 31, 2007). These rates over LIBOR were adjusted in May 2007 to be 1.00% to 1.75%. 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 pretax SEC PV-10 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, 2007, our current ratio was 1.8 to 1.0, as adjusted per current agreements, and our leverage ratio was 0.9 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 obtained a waiver of any breach of a loan covenant arising out of Calpine's institution of Calpine's fraudulent conveyance action against us and were in compliance with all covenants at December 31, 2007. All amounts drawn under the Revolver are due and payable on July 7, 2009. Availability under the revolving line of credit was $179.0 million at December 31, 2007.

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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% (8.82% at December 31, 2007). 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 obtained a waiver of any breach of a loan covenant arising out of Calpine's institution of Calpine's fraudulent conveyance action against us and were in compliance with all covenants at December 31, 2007. The revised principal balance of the Term Loan is due and payable on July 7, 2010.

Our ability to raise capital depends on the current state of the financial markets, which are subject to general and economic and industry conditions. Therefore, the availability of and price of capital in the financial markets could negatively affect our liquidity position. Our current liquidity is supported by our revolving credit facility maturing on July 7, 2009.

Working Capital

At December 31, 2007, we had a working capital deficit of $62.9 million as compared to a working capital surplus of $30.7 million at December 31, 2006. 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. This deficit was largely caused by the decrease in our cash balance to fund capital expenditures, including property acquisitions as well as an increase in our accrued capital costs. As of December 31, 2007, the working capital asset balances of our cash and cash equivalents and derivative instruments were approximately $3.2 million and $4.0 million, respectively, and there was no balance for current deferred tax assets. In addition, the associated working capital liability balances for accrued liabilities were approximately $64.2 million as of December 31, 2007.

We believe we have adequate expected cash flows from operations and available borrowings under our Revolver to fund our budgeted capital expenditures.

Cash Flows

	Successor-Consolidated			Predecessor-Combined
	Year Ended December 31, 2007	Year Ended December 31, 2006	Six Months Ended December 31, 2005	Six Months Ended June 30, 2005
			(In thousands)	
Cash flows provided by operating activities	$ 257,307	$ 199,610	$ 63,744	$ 59,379
Cash flows used in investing activities	(322,041)	(236,064)	(943,246)	(30,645)
Cash flows provided by (used in) financing activities	5,170	(490)	979,226	(27,239)

Net (decrease) increase in cash and cash equivalents	$	(59,564)	$	(36,944)	$	99,724	$	1,495

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 and general and administrative expenses. Net cash provided by operating activities ("Operating Cash Flow") continued to be a primary source of liquidity and capital used to finance our capital expenditures for the year ended December 31, 2007.

Cash flows provided by operating activities increased by $57.7 million for the year ended December 31, 2007 as compared to the same period for 2006. This increase is largely affected by our net income, excluding non-cash expenses such as depreciation, depletion and amortization and deferred income taxes. For the year ended December 31, 2007, we had net income of $57.2 million with an increase of production of 37% as compared to the year ended December 31, 2006 with net income of $44.6 million. As noted above, we also had a working capital deficit of $62.9 million, which was largely caused by the decrease in our cash balance to fund capital expenditures, including property acquisitions. For the year ended December 31, 2007, we incurred approximately $336.1 million in capital expenditures as compared to $242.2 million for the year ended December 31, 2006.

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Net cash provided by operating activities for the year ended December 31, 2006 was $199.6 million with net income of $44.6 million and 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 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.

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

Cash flows used in investing activities increased by $86.0 million for the year ended December 31, 2007 as compared to the same period for 2006 and related to our expenditures for the acquisition of the OPEX properties and drilling and development of oil and gas properties. During the year ended December 31, 2007, we participated in the drilling of 195 gross wells as compared to the drilling of 142 gross wells for the year ended December 31, 2006.

Cash used in investing activities for the year ended December 31, 2006 was $236.1 million. 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.

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

Cash flows provided by financing activities increased by $5.7 million for the year ended December 31, 2007 as compared to the same period for 2006. The net increase is primarily related to net borrowings of $5.0 million made in 2007 against the Revolver. In addition, there were fewer purchases of treasury stock for the year ended December 31, 2007 than for the comparable period in 2006. The purchases of stock were surrendered by certain employees to pay tax withholding upon vesting of restricted stock awards. These purchases are not part of a publicly announced program to repurchase shares of our common stock, nor do we have a publicly announced program to purchase shares of common stock.

Net cash used in financing activities for the year ended December 31, 2006 was 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.

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.

Commodity Price Risks 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, basis 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.

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We also entered into a series of basis swaps transactions covering a portion of our 2008 production. The basis swap requires us to pay Natural Gas Intelligence ("NGI") PG&E Citygate Index for notional volumes for calendar year 2008. The counterparty will pay the float price based on the last trade day settlement of the corresponding forward month contract settlement of the NYMEX Henry Hub index. When combined with existing NYMEX Henry Hub fixed price swaps, this effectively creates a fixed price swap that settles at PG&E Citygate Index. Consistent with our hedge policy the basis swap transactions will be combined with the NYMEX fixed price swaps noted above and treated as PG&E fixed price swaps in subsequent disclosures. See "Item 7A. Quantitative and Qualitative Disclosure About Market Risk".

The following table sets forth the results of commodity hedging transaction settlements for the year ended December 31, 2007:

	For the Year Ended December 31, 2007	For the Year Ended December 31, 2006
Natural Gas		
Quantity settled (MMBtu)	23,464,500	20,075,000
Increase in natural gas sales revenue (In thousands)	$ 22,926	$ 29,578

Interest Rate Risks and Related Hedging Activities

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 interest rates. To mitigate this exposure, we have entered into a series of interest rate swap agreements through June 2009 to mitigate such risk. If we determine the risk may become substantial and the costs are not prohibitive, we may enter into additional interest rate swap agreements in the future.

The following table sets forth the results of third party interest rate hedging transactions settled for the year ended December 31, 2007:

	For the Year Ended December 31, 2007	For the Year Ended December 31, 2006
Interest Rate Swaps		
Decrease in interest expense (In thousands)	$ 20	$ -

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 commodity and interest rate hedge positions are with counterparties that are lenders in our credit facilities. This allows us to secure 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, 2007, we had no deposits for collateral.

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, 2007 were $336.1 million, and we currently expect to expend approximately $290.1 million during 2008. We believe we have adequate expected cash flows from operations and available borrowings under our Revolver to fund our budgeted capital expenditures.

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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, 2007, the aggregate amounts of our contractually obligated payment commitments for the next five years are as follows:

	Payments Due By Period				
	Total	2008	2009 to 2010	2011 to 2012	2013 & Beyond
	(In thousands)				
Senior secured revolving line of credit	$ 170,000	$ -	$ 170,000	$ -	$ -
Second lien term loan	75,000	-	75,000	-	-
Operating leases	16,418	2,365	5,455	5,535	3,063
Interest payments on long-term debt (1)	31,590	16,514	15,076	-	-
Rig commitments	4,100	4,100	-	-	-
Total contractual obligations	$ 297,108	$ 22,979	$ 265,531	$ 5,535	$ 3,063

(1) Future interest payments were calculated based on interest rates and amounts outstanding at December 31, 2007.

Asset retirement Obligation. The Company also has liabilities of $22.7 million related to asset retirement obligations on its Consolidated Balance Sheet at December 31, 2007 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 Item 8. Consolidated Financial Statements and Supplementary Data Note 9, Asset Retirement Obligation.

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 interests in title to certain domestic oil and natural gas leases and wells, 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 to such interests. In July 2005, as part of the transactions undertaken in connection with closing the Acquisition, we accepted possession of and have since been operating substantially all of the interests in leases, wells and easements, for which Calpine retained record legal title. We withheld approximately $75 million from the aggregate purchase price, which was an agreed dollar amount under the Purchase Agreement with respect to the Non-Consent 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. 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 continue to be withheld by us and available for general corporate purposes.

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 and Related Matters

Calpine 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., ("CPS") which filed for bankruptcy, is providing services to the Company under a new marketing and services agreement ("MSA"). The initial MSA was entered into by the Company and Calpine in July 2005 and ran through June 30, 2007. Under a new marketing and service agreement executed in conjunction with the PTRA, CPS is to provide services through June 30, 2009, subject to earlier termination by the Company in certain events.

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Additionally, on June 29, 2007, Calpine filed a Lawsuit against us seeking $400 million plus interest as a result of an alleged shortfall in value received for the assets involved in the Acquisition, or in the alternative, a return of the domestic oil and gas assets sold to us by Calpine. We have answered the Lawsuit and filed our counterclaims.

The Bankruptcy filing and Lawsuit raises certain concerns regarding aspects of our relationship with Calpine and certain of its subsidiaries, which we will continue to closely monitor and, as needed, vigorously protect our interests. See further discussion of our concerns under Item 1A. Risk Factors and Item 3. Legal Proceedings.

Calpine and certain of its subsidiaries have since emerged from bankruptcy.

Off-Balance Sheet Arrangements

At December 31, 2007 and 2006, 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.

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;

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- 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;
- General economic conditions, either internationally, nationally or in jurisdictions affecting our business;
- The amount of resources expended in connection with Calpine's bankruptcy and its fraudulent conveyance action, including significant ongoing costs for lawyers, consultants, experts and all related expenses, as well as all lost opportunity costs associated with our internal resources dedicated to these matters and possible impacts on our reputation;
- 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, 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, 2007, our annual income before income taxes would change by approximately $4.3 million for each $0.10 per Mfe change in natural gas prices and approximately $0.6 million for each $1.00 per Bbl change in crude oil prices, excluding the effects of hedging.

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, 2007, 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 N otional Volume MMBtu	Average Underlying Prices MMBtu	Total of Proved Natural Gas Production Hedged (1)	Fair Market Value Gain/(Loss) (In thousands)
2008	Swap	Cash Flow	64,909	23,756,616	$ 7.74	49%	$ 2,302
2009	Swap	Cash Flow	42,141	15,381,465	7.49	35%	(13,165)
				39,138,081			$ (10,863)

(1) Estimated based on net gas reserves presented in the December 31, 2007 Netherland, Sewell & Associates, Inc. reserve report.

In 2008, we entered into an additional 23,000 MMBtu per day of financial fixed price swaps covering a portion of our production for 2008 through 2010 at an average underlying price of $8.27 per MMBtu. We also entered into a series of costless collars for 10,000 MMBtu per day for a portion of our production in 2008 and 2009 with an average floor price of $8.00 per MMBtu and an average ceiling price of $10.28 per MMBtu.

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 borrowing base is $350 million and 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 1.00% to 1.75%, 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 due to the repayment of $25 million. Borrowings under the Term Loan initially bore interest at LIBOR plus 5.00%. The interest rate for the 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.

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We had availability under the Revolver of $179.0 million as of December 31, 2007. A one hundred basis point increase in each of the LIBOR rate and federal funds rate as of December 31, 2007 and 2006 for both our Revolver and Term Loan would result in an estimated $2.5 million and $2.4 million increase, respectively, in annual interest expense.

In 2007, we entered into a series of fixed rate swap agreements for a portion of our variable rate debt. Our fixed-rate swap agreements are used to fix the interest rate we pay under our variable rate credit facilities. The fixed-rate swaps are freestanding financial agreements that require us and the counterparty to net cash settle our gains and losses on a monthly basis. Upon settlement, we receive a floating market LIBOR rate and pay our counterparty a fixed interest rate, as defined in each instrument. When the floating rate exceeds the fixed rate for a contract month, our counterparty pays us. When the fixed price exceeds the floating price, we are required to make a payment to our counterparty. We have designated these swaps as cash flow hedges.

We have hedged the interest rates on $75.0 million of our variable rate debt through 2008 and $50.0 million through 2009. As of December 31, 2007 we had the following financial interest rate swap positions outstanding:

Settlement Period	Derivative Instrument	Hedge Strategy	Average Fixed Rate		Fair Market Value Gain/(Loss) (In thousands)
2008	Swap	Cash Flow	4.41%	$	(369)
2009	Swap	Cash Flow	4.55%		(282)
				$	(651)

Derivative Instruments and Hedging Activities

We use derivative transactions to manage exposure to changes in commodity prices and interest rates. 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 interest rate 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 interest rates 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 or variable rate debt and thus provide only partial price protection against declines in commodity prices or rising interest rates. We expect that the amount of our derivative contracts will vary from time to time.

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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 accompanying consolidated balance sheets and the related consolidated statements of operations, of cash flows and of stockholders' equity and comprehensive income present fairly, in all material respects, the financial position of Rosetta Resources Inc. and its subsidiaries (successor, the "Company") at December 31, 2007 and 2006, and the results of their operations and their cash flows for each of the two years in the period ended December 31, 2007 and the six months in the period ended December 31, 2005 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2007, based on criteria established in Internal Control - Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in Management's Report on Internal Control Over Financial Reporting appearing under Item 9A. Our responsibility is to express opinions on these financial statements and on the Company's internal control over financial reporting based on our audits (which was an integrated audit in 2007). We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included 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. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

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 a lawsuit against the Company related to the acquisition of the oil and natural gas business of Calpine Corporation and Affiliates.

A company’s internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company’s internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company’s assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ PricewaterhouseCoopers LLP

February 29, 2008
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 owner's net investment for the six months in the period ended June 30, 2005 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, the “Company”) for the six months in the period ended June 30, 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 audit. We conducted our audit 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 audit provides a reasonable basis for our opinion.

As described in Note 16 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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Item 8. Financial Statements and Supplementary Data

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

	December 31, 2007	December 31, 2006
Assets		
Current assets:		
Cash and cash equivalents	$ 3,216	$ 62,780
Accounts receivable	55,048	36,408
Derivative instruments	3,966	20,538
Prepaid expenses	10,413	8,761
Other current assets	4,249	2,965
Total current assets	76,892	131,452
Oil and natural gas properties, full cost method, of which $40.9 million at December 31, 2007 and $37.8 million at December 31, 2006 were excluded from amortization	1,566,082	1,223,337
Other	6,393	4,562
	1,572,475	1,227,899
Accumulated depreciation, depletion, and amortization	(295,749)	(145,289)
Total property and equipment, net	1,276,726	1,082,610
Deferred loan fees	2,195	3,375
Other assets	1,401	1,968
Total other assets	3,596	5,343
Total assets	$ 1,357,214	$ 1,219,405
Liabilities and Stockholders' Equity		
Current liabilities:		
Accounts payable	$ 33,949	$ 23,040
Accrued liabilities	64,216	43,099
Royalties payable	18,486	9,010
Derivative instruments	2,032	-
Prepayment on gas sales	20,392	17,868
Deferred income taxes	720	7,743
Total current liabilities	139,795	100,760
Long-term liabilities:		
Derivative instruments	13,508	11,014
Long-term debt	245,000	240,000
Asset retirement obligation	18,040	10,253
Deferred income taxes	67,916	35,089
Total liabilities	484,259	397,116
Commitments and contingencies (Note 11)		
Stockholders' equity:		
Preferred stock, $0.001 par value; authorized 5,000,000 shares; no shares issued in 2007 or 2006	-	-
Common stock, $0.001 par value; authorized 150,000,000 shares; issued 50,542,648 shares and 50,405,794 shares at December 31, 2007 and December 31, 2006, respectively	50	50

Additional paid-in capital	762,827	755,343
Treasury stock, at cost; 109,303 shares and 85,788 shares at December 31, 2007 and December 31, 2006, respectively	(2,045)	(1,562)
Accumulated other comprehensive (loss) income	(7,225)	6,315
Retained earnings	119,348	62,143
Total stockholders' equity	872,955	822,289
Total liabilities and stockholders' equity	$ 1,357,214	$ 1,219,405

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, 2007	Year Ended December 31, 2006	Six Months Ended December 31, 2005	Six Months Ended June 30, 2005
Revenues:				
Natural gas sales	$ 323,341	$ 236,496	$ 102,058	$ 13,713
Oil sales	40,148	35,267	11,046	8,166
Oil and natural gas sales to affiliates	-	-	-	81,952
Total revenues	363,489	271,763	113,104	103,831
Operating costs and expenses:				
Lease operating expense	47,044	36,273	15,674	16,629
Depreciation, depletion, and amortization	152,882	105,886	40,500	30,679
Exploration expense	-	-	-	2,355
Dry hole costs	-	-	-	1,962
Treating and transportation	4,230	2,544	1,286	1,998
Affiliated marketing fees	-	-	-	913
Marketing fees	2,450	2,257	1,379	-
Production taxes	6,417	6,433	3,975	2,755
General and administrative costs	43,867	33,233	14,687	9,677
Total operating costs and expenses	256,890	186,626	77,501	66,968
Operating income	106,599	85,137	35,603	36,863
Other (income) expense				
Interest expense with affiliates, net of interest capitalized	-	-	-	6,995
Interest expense, net of interest capitalized	17,734	17,428	8,216	-
Interest income	(1,674)	(4,503)	(1,837)	(516)
Other (income) expense, net	(698)	(40)	152	207
Total other expense	15,362	12,885	6,531	6,686
Income before provision for income taxes	91,237	72,252	29,072	30,177
Provision for income taxes	34,032	27,644	11,537	11,496
Net income	$ 57,205	$ 44,608	$ 17,535	$ 18,681
Earnings per share:				
Basic	$ 1.14	$ 0.89	$ 0.35	$ 0.37
Diluted	$ 1.13	$ 0.88	$ 0.35	$ 0.37
Weighted average shares outstanding:				
Basic	50,379	50,237	50,003	50,000
Diluted	50,589	50,408	50,189	50,160

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, 2007	Year Ended December 31, 2006	Six Months Ended December 31, 2005	Six Months Ended June 30, 2005
Cash flows from operating activities				
Net income	57,205	44,608	17,535	18,681
Adjustments to reconcile net income to net cash from operating activities				
Depreciation, depletion and amortization	152,882	105,886	40,500	30,679
Affiliate interest expense	-	-	-	(6,995)
Deferred income taxes	33,915	27,472	11,537	2,874
Amortization of deferred loan fees recorded as interest expense	1,180	1,180	590	-
Stock compensation expense	6,831	5,702	4,248	-
Other non-cash charges	(181)	(171)	(241)	(62)
Change in operating assets and liabilities:				
Accounts receivable	(18,640)	3,643	(40,051)	2,378
Accounts receivable from affiliates	-	-	-	6,298
Income taxes receivable	-	6,000	(6,000)	-
Prepaid expenses	(1,652)	650	(9,411)	2,563
Other current assets	(1,284)	(2,965)	-	-
Other assets	144	1,691	(1,726)	-
Accounts payable	10,909	8,765	13,442	(4,494)
Accrued liabilities	3,998	310	3,282	241
Royalties payable	12,000	(3,161)	30,039	(1,406)
Income taxes payable	-	-	-	8,622
Net cash provided by operating activities	257,307	199,610	63,744	59,379
Cash flows from investing activities				
Acquisition of Calpine, net of cash acquired	-	-	(910,064)	-
Acquisition of oil and gas properties	(38,656)	(35,286)	-	-
Purchases of property and equipment	(284,541)	(201,293)	(32,994)	(32,202)
Disposals of property and equipment	1,105	30	13	1,447
Other	51	485	(201)	110
Net cash used in investing activities	(322,041)	(236,064)	(943,246)	(30,645)
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	10,000	-	225,000	-
Payments on revolving credit facility	(5,000)	-	(60,000)	-
Loan fees	-	-	(5,145)	-
Notes payable to affiliates	-	-	-	(27,239)
Proceeds from issuances of common stock	653	804	-	-

Purchases of treasury stock		(483)		(1,562)		-		-
Net cash provided by (used in) financing activities		5,170		(490)		979,226		(27,239)
Net (decrease) increase in cash		(59,564)		(36,944)		99,724		1,495
Cash and cash equivalents, beginning of period		62,780		99,724		-		-
Cash and cash equivalents, end of period	$	3,216	$	62,780	$	99,724	$	1,495
Supplemental disclosures:								
Cash paid for interest expense, net of capitalized Interest	$	18,862	$	17,875	$	(8,057)	$	-
Cash paid for tax	$	115	$	172	$	6,000	$	-
Supplemental non-cash disclosures:								
Capital expenditures included in accrued liabilities	$	12,925	$	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 Changes in Stockholders' Equity and Changes in Owner's Net Investment
(In thousands, except share amounts)

	Common Stock		Additional	Treasury Stock		Accumulated Other		Total Stockholders' Equity & Owner's Net
Predecessor	Shares	Amount	Paid-In Capital	Shares	Amount	Comprehensive (Loss)/Income	Retained Earnings	Investment
Balance January 1, 2005	-	-	-	-	-	-	-	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 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 options exercised	49,896	-	804	-	-	-	-	804
Treasury stock - employee tax payment	-	-	-	85,788	(1,562)	-	-	(1,562)
Stock-based compensation	-	-	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) related to cash flow hedges	-	-	-	-	-	(34,916)	-	(34,916)
Comprehensive Income	-	-	-	-	-	-	-	101,654
Balance December 31, 2006	50,405,794	$ 50	$ 755,343	85,788	$ (1,562)	$ 6,315	$ 62,143	$ 822,289
Stock options exercised	40,104	-	653	-	-	-	-	653
Treasury stock - employee tax payment	-	-	-	23,515	(483)	-	-	(483)
Stock-based compensation	-	-	6,831	-	-	-	-	6,831
Vesting of restricted stock	96,750	-	-	-	-	-	-	-
Comprehensive Income:	-	-	-	-	-	-	-	-
Net Income	-	-	-	-	-	-	57,205	57,205
Change in fair value of derivative hedging instruments	-	-	-	-	-	1,276	-	1,276
Hedge settlements reclassified to income	-	-	-	-	-	(22,926)	-	(22,926)
Tax benefit related to cash flow hedges	-	-	-	-	-	8,110	-	8,110
Comprehensive Income	-	-	-	-	-		-	43,665
Balance December 31, 2007	50,542,648	50	762,827	109,303	(2,045)	(7,225)	119,348	$ 872,955

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., its partners, and 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") and Rosetta Resources California, LLC, Rosetta Resources Rockies, LLC, Rosetta Resources Offshore, LLC and Rosetta Resources Texas LP and its partners in July 2005 (hereinafter, the "Acquisition") and, together with all subsequently acquired oil and natural 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 Rocky Mountains, the Lobo and Perdido Trends in South Texas, the State Waters of Texas and the Gulf of Mexico.

Certain reclassifications of prior year balances have been made to conform such amounts to corresponding 2007 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 interests in certain leases and wells associated with the non-consent properties described in Note 11 pertaining to the Calpine bankruptcy, 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. For additional information see Note 11 to the Consolidated/Combined Financial Statements.

The unaudited pro forma information below for the year ended December 31, 2005 assumes the acquisition of Calpine's domestic oil and natural gas business and the related financings occurred at the beginning of the period 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 (In thousands, except per share amounts) (Unaudited)	
Revenues	$	207,501
Net income		26,437
Basic earnings per common share		0.53
Diluted earnings per common share	$	0.53

(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 accompanying consolidated financial statements for the years ended December 31, 2007 and 2006 and for the six months ended December 31, 2005 contain the accounts of Rosetta Resources Inc. and its majority owned subsidiaries after eliminating all significant intercompany balances and transactions.

The Predecessor combined financial statements for the six months ended June 30, 2005 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 Calpine. The allocations have been made on a reasonable basis and have been consistently applied for the periods presented.

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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 including uncertain tax positions, the outcome of pending litigation, stock-based compensation, 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.

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.

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, including salaries, benefits and other internal costs directly attributable to these activities, are capitalized when incurred into cost centers that are established on a country-by-country basis, 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, unevaluated properties and significant development projects 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 $5.5 million and $3.4 million of internal costs for the years ended December 31, 2007 and 2006, 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 or reserves are sold.

The Company assesses the impairment for oil and natural gas properties 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.

The Company’s ceiling test computation was calculated using hedge adjusted market prices at December 31, 2007, which were based on a Henry Hub price of $6.80 per MMBtu and a West Texas Intermediate oil price of $92.50 per Bbl (adjusted for basis and quality differentials). The use of these prices would have resulted in a pre-tax writedown of $21.5 million at December 31, 2007. However, we reevaluated our ceiling test exposure on February 22, 2008 using the market price for Henry Hub of $8.91 per MMBtu and the price for West Texas Intermediate of $98.88 per Bbl. Utilizing these prices, the calculated ceiling amount exceeded our net capitalized cost of oil and gas properties. As a result, no write-down was recorded for the year ended December 31, 2007. Due to the volatility of commodity prices, should natural gas prices decline in the future, it is possible that a write-down could occur.

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No impairment charge was recorded for the year ended December 31, 2006 or 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.

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. 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 related to unevaluated properties and significant development projects in accordance with SFAS No. 34, “Capitalization of Interest Cost,” (“SFAS No. 34”). As proved reserves are established or impairment determined, the related capitalized interest is included in costs subject to amortization.

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. Derivatives are also recorded on the balance sheet at fair market value. As of December 31, 2007 and 2006, the carrying value of our debt was approximately $245 million and $240 million, respectively. 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.

Concentrations of Credit Risk

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.

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 the term of the related debt using the straight-line method, which approximates the effective interest method.

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 also uses derivatives to manage interest rate risk associated with its debt under its credit facility. 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 or interest rate and a variable price or LIBOR rate for a fixed notional quantity or amount 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 or debt under its current credit agreements.

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 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.

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, and such costs are included in the calculation of DD&A expense. 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.

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.

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. There were no significant environmental liabilities at December 31, 2007 or 2006.

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.

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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 $0.1 million of related excess tax benefits which will be recognized upon utilization of our net operating loss carryforward.

Preferred Stock

The Company is authorized to issue 5,000,000 shares of preferred stock with preferences and rights as determined by the Company's Board of Directors. As of December 31, 2007 and 2006, there were no shares outstanding.

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.

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, 2007 and 2006, 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, natural gas liquids and crude oil 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. 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.

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.

FASB Interpretation No. 48, “Accounting for Uncertainty in Income Taxes - an interpretation of FASB Statement No. 109” (“FIN 48”) requires that we recognize the financial statement benefit of a tax position only after determining that the relevant tax authority would more likely than not sustain the position following an audit. For tax positions meeting the more likely than not threshold, the amount recognized in the financial statements is the largest benefit that has a greater than 50% likelihood of being realized upon ultimate settlement with the relevant tax authority.

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Recent Accounting Developments

Noncontrolling Interests in Consolidated Financial Statements. In December 2007, the Financial Accounting Standards Board ("FASB") issued SFAS No. 160, "Noncontrolling Interests in Consolidated Financial Statements, an amendment of Accounting Research Bulletin No. 51" (SFAS No. 160), which improves the relevance, comparability and transparency of the financial information that a reporting entity provides in its consolidated financial statements by establishing accounting and reporting standards for the noncontrolling interest in a subsidiary and for the deconsolidation of a subsidiary. This statement is effective for fiscal years beginning after December 15, 2008. The Company does not expect the adoption of SFAS No. 160 to have a material impact on the Company's consolidated financial position, results of operations or cash flows.

Business Combinations. In December 2007, FASB issued SFAS No. 141(R), "Business Combinations" ("SFAS No. 141R"), which creates greater consistency in the accounting and financial reporting of business combinations. This statement is effective for fiscal years beginning after December 15, 2008. The Company does not expect the adoption of SFAS No. 141R to have a material impact on the Company's consolidated financial position, results of operations or cash flows.

The Fair Value Option for Financial Assets and Financial Liabilities. In February 2007, 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 does not expect the adoption of SFAS No. 159 to have a material impact on the Company's consolidated financial position, results of operations or cash flows as the Company did not choose to measure at fair value.

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 FASB has also issued Staff Position FAS 157-2 ("FSP No. 157-2"), which delays the effective date of SFAS No. 157 for nonfinancial assets and liabilities, except for items that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually), until fiscal years beginning after November 15, 2008. The Company does not expect the adoption of SFAS No. 157 or FSP No. 157-2 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, 2007	December 31, 2006
	(In thousands)	
Natural gas, NGLs and oil revenue sales	$ 46,376	$ 34,027
Joint interest billings	7,750	959
Short-term receivable for royalty recoupment	922	1,422
Total	55,048	36,408

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, 2007 and December 31, 2006.

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(5) Property, Plant and Equipment

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

	December 31, 2007	December 31, 2006
	(In thousands)	
Proved properties	$ 1,499,046	$ 1,167,588
Unproved/unevaluated properties	40,903	37,813
Gas gathering system and compressor station	26,133	17,936
Other	6,393	4,562
Total	1,572,475	1,227,899
Less: Accumulated depreciation, depletion, and amortization	(295,749)	(145,289)
	$ 1,276,726	$ 1,082,610

Included in the Company’s oil and natural gas properties are asset retirement costs of $20.1 million and $9.6 million at December 31, 2007 and 2006, respectively, including additions of $2.1 million and $0.5 million for the year ended December 31, 2007 and 2006, respectively.

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At December 31, 2007 and 2006, the Company excluded the following capitalized costs from depreciation, depletion and amortization:

	December 31, 2007	December 31, 2006
	(In thousands)	
Onshore:		
Development cost		
Incurred in 2007	$ 591	$ -
Incurred in 2006	-	-
Incurred in 2005	-	-
Exploration cost		
Incurred in 2007	5,650	-
Incurred in 2006	-	2,635
Incurred in 2005	-	-
Acquisition cost of undeveloped acreage		
Incurred in 2007	9,023	-
Incurred in 2006	7,568	9,976
Incurred in 2005	8,404	16,978
Capitalized interest		
Incurred in 2007	2,026	-
Incurred in 2006	999	1,925
Incurred in 2005	36	228
Total	34,297	31,742
Offshore:		
Exploration cost		
Incurred in 2007	-	-
Incurred in 2006	-	-
Incurred in 2005	-	-
Acquisition cost of undeveloped acreage		
Incurred in 2007	209	-
Incurred in 2006	5,860	5,860
Incurred in 2005	-	-
Capitalized interest		
Incurred in 2007	381	-
Incurred in 2006	150	184
Incurred in 2005	6	27
Total	6,606	6,071
Total costs excluded from depreciation, depletion, and amortization	$ 40,903	$ 37,813

It is anticipated that the acquisition of undeveloped acreage and associated capitalized interest of $34.7 million and development and exploration costs of $6.2 million will be included in depreciation, depletion and amortization within five years and one year, respectively.

Property Acquisitions. During the second quarter of 2007, the Company acquired properties located in the Sacramento Basin from Output Exploration , LLC and OPEX Energy, LLC at a total purchase price of $38.7 million.

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 System and compressor station. The gas gathering system and compressor station of $26.1 million and $17.9 million at December 31, 2007 and 2006, respectively, is located in California and the Rocky Mountains. The gas gathering system and compressor station are recorded at cost and depreciated on a straight-line basis over useful lives of 15 years. The accumulated depreciation for the gas gathering system at December 31, 2007 and 2006 was $3.0 million and $1.5 million, respectively. The depreciation expense associated with the gas gathering system and compressor station for the years ended December 31, 2007 and 2006 (Successor), six months ended December 31, 2005 (Successor) and the six months ended June 30, 2005 (Predecessor) was $1.5 million, $1.0 million, $0.5 million and $0.6 million, respectively.

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Other Property and Equipment. Other property and equipment at December 31, 2007 and 2006 of $6.4 million and $4.6 million, respectively, consists primarily of furniture and fixtures. The accumulated depreciation associated with other assets at December 31, 2007 and 2006 was $1.4 million and $0.6 million, respectively. For the years ended December 31, 2007 and 2006 (Successor), six months ended December 31, 2005 (Successor) and six months ended June 30, 2005 (Predecessor), depreciation expense for other property and equipment was $0.8 million, $0.5 million, $0.1 million and $0.4 million, respectively.

(6) Deferred Loan Fees

At December 31, 2007 and 2006, deferred loan fees were $2.2 million and $3.4 million, respectively. Total amortization expense for deferred loan fees was $1.2 million for the years ended December 31, 2007 and 2006, respectively, and $0.6 million for the six months ended December 31, 2005.

(7) Commodity Hedging Contracts and Other Derivatives

The Company entered into a series of basis swaps transactions covering a portion of the Company's 2007 and 2008 production. The basis swap requires the Company to pay Natural Gas Intelligence ("NGI") PG&E Citygate Index for notional volumes for calendar year 2008. The counterparty pays the float price based on the last trade day settlement of the corresponding forward month contract settlement of the NYMEX Henry Hub index. When combined with existing NYMEX Henry Hub fixed price swaps, this effectively creates a fixed price swap that settles at PG&E Citygate Index. Consistent with our hedge policy, the basis swap transactions were combined with the NYMEX fixed price swaps and treated as PG&E fixed price swaps. The combined fixed price swap is included in the financial fixed price swaps positions noted below.

The Company has entered into financial fixed price swaps with prices ranging from $6.81 per MMBtu to $8.63 per MMBtu covering a portion of the Company's 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, 2007:

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)
2008	Swap	Cash Flow	64,909	23,756,616	$ 7.74	49%	$ 2,302
2009	Swap	Cash Flow	42,141	15,381,465	7.49	35%	(13,165)
				39,138,081			$ (10,863)

(1) Estimated based on net gas reserves presented in the December 31, 2007 Netherland, Sewell, & Associates, Inc. reserve report.

The Company has hedged the interest rates on $75.0 million of its outstanding debt through 2008 and $50.0 million through 2009. As of December 31, 2007, the Company had the following financial interest rate swap positions outstanding:

Settlement	Derivative	Hedge	Fair Market

Period	Instrument	Strategy	Average Fixed Rate	Value Gain/(Loss) (In thousands)
2008	Swap	Cash Flow	4.41%	$ (369)
2009	Swap	Cash Flow	4.55%	(282)
				$ (651)

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, 2007, the Company made no deposits for collateral.

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The following table sets forth the results of hedge transaction settlements for the respective period for the Consolidated Statement of Operations:

	For the Year Ended December 31, 2007	For the Year Ended December 31, 2006
Natural Gas		
Quantity settled (MMBtu)	23,464,500	20,075,000
Increase in natural gas sales revenue (In thousands)	$ 22,926	$ 29,578

The following table sets forth the results of third party interest rate hedging transactions settled for the Consolidated Statement of Operations:

	For the Year Ended December 31, 2007	For the Year Ended December 31, 2006
Interest Rate Swaps		
Decrease in interest expense (In thousands)	$ 20	$ -

The Company expects to reclassify gains of $1.2 million based on market pricing as of December 31, 2007 to earnings from the balance in accumulated other comprehensive income (loss) on the Consolidated Balance Sheet during the next twelve months.

At December 2007, the Company had derivative assets of $4.0 million, of which $0.1 million is included in other assets on the Consolidated Balance Sheet. The Company also had derivative liabilities of $15.5 million, of which $2.0 million is included in current liabilities on the Consolidated Balance Sheet at December 31, 2007.

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, 2007 and 2006.

In 2008, the Company entered into an additional 23,000 MMBtu per day of financial fixed price swaps covering a portion of the Company’s production for 2008 through 2010 at an average underlying price of $8.27 per MMBtu. The Company also entered into a series of costless collars for 10,000 MMBtu per day for a portion of the Company’s production in 2008 and 2009 with an average floor price of $8.00 per MMBtu and an average ceiling price of $10.28 per MMBtu.

(8) Accrued Liabilities

The Company’s accrued liabilities consists of the following:

	December 31, 2007	December 31, 2006
	(In thousands)	
Accrued capital costs	$ 34,599	$ 21,674
Accrued purchase price adjustments	11,400	11,400
Accrued payroll and employee incentive expense	5,361	3,028
Accrued lease operating expense	4,930	5,252
Asset Retirement Obligation	4,629	435
Other	3,297	1,310

Total	$ 64,216	$ 43,099

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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,			
	2007		2006	
	(In thousands)			
ARO as of the beginning of the period	$	10,689	$	9,467
Revision of previous estimate		9,751		-
Liabilities incurred during period		2,105		467
Liabilities settled during period		(1,355)		(33)
Accretion expense		1,480		788
ARO as of the end of the period	$	22,670	$	10,689

Of the total ARO, approximately $4.6 million and $0.4 million is included in accrued liabilities on the Consolidated Balance Sheet at December 31, 2007 and 2006, respectively.

(10) Long-Term Debt

Long-term debt consists of the following:

	December 31,			
	2007		2006	
	(In thousands)			
Senior secured revolving line of credit	$	170,000	$	165,000
Second lien term loan		75,000		75,000
		245,000		240,000
Less: current portion of long-term debt		-		-
	$	245,000	$	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. In addition, in 2007, we increased our net borrowings against the Revolver by $5.0 million, bringing the balance to $170.0 million at December 31, 2007. 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. In May 2007, the borrowing base was adjusted to $350.0 million. Initial amounts outstanding under the Revolver bore interest, as amended, at specified margins over the London Interbank Offered Rate ("LIBOR") of 1.25% to 2.00% (5.82% at December 31, 2007). These rates over LIBOR were adjusted in May 2007 to be 1.00% to 1.75%. 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 pretax SEC PV-10 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, 2007. As of December 31, 2007, the Company had $179.0 million available for borrowing under their revolving line of credit. All amounts drawn under the Revolver are due and payable on July 7, 2009.

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% (8.82 % at December 31, 2007). 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, 2007. The principal balance of the Term Loan is due and payable on July 7, 2010.

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Our ability to raise capital depends on the current state of the financial markets, which are subject to general and economic and industry conditions. Therefore, the availability of and price of capital in the financial markets could negatively affect our liquidity position. Our current liquidity is supported by our revolving credit facility maturing on July 7, 2009.

Aggregate maturities required on long-term debt at December 31, 2007 due in future years are as follows (In thousands):

2007	$ -
2008	-
2009	170,000
2010	75,000
2011	-
Thereafter	-
Total	$ 245,000

(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

On December 20, 2005, Calpine 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 19, 2007, the Bankruptcy Court approved Calpine's plan of reorganization ("Plan of Reorganization"). On January 31, 2008, Calpine and certain of its subsidiaries emerged from bankruptcy.

Calpine's Lawsuit Against Rosetta

On June 29, 2007, Calpine commenced an adversary proceeding against the Company in the Bankruptcy Court (the "Lawsuit"). The complaint alleges that the purchase by the Company of the domestic oil and natural gas business owned by Calpine (the "Assets") in July 2005 for $1.05 billion, prior to Calpine filing for bankruptcy, was completed when Calpine was insolvent and was for less than a reasonably equivalent value. Through the Lawsuit, Calpine is seeking (i) monetary damages for the alleged shortfall in value it received for these Assets which it estimates to be approximately $400 million, plus interest, or (ii) in the alternative, return of the Assets from the Company. The Company believes that the allegations in the Lawsuit are wholly baseless, and the Company continues to believe that it is unlikely that this challenge by Calpine to the fairness of the Acquisition will be successful upon the ultimate disposition of the Lawsuit or, if necessary, in the appellate courts. The Official Committee of Equity Security Holders and the Official Committee of the Unsecured Creditors both intervened in the Lawsuit for the stated purpose of monitoring the proceedings because the committees claimed to have an interest in the Lawsuit, which the Company disputes because we believe creditors may be paid in full under Calpine's Plan of Reorganization without regard to the Lawsuit and equity holders have no interest in fraudulent conveyance actions. Under Calpine's Plan of Reorganization approved by the Bankruptcy Court on December 19, 2007, the Official Committee of Equity Security Holders was dissolved as of the January 31, 2008 effective date and no longer has any interest in the Lawsuit. While the Unsecured Creditors Committee also was officially dissolved as of the same effective date, there are provisions under the approved Plan of

Reorganization that will allow it to remain involved in lawsuits to which it is a party, which may include this Lawsuit

On September 10, 2007, the Company filed a motion to dismiss the Lawsuit or, in the alternative, to stay the Lawsuit. The Bankruptcy Court conducted a hearing upon the Company's motion on October 24, 2007. Following the hearing, the Bankruptcy Court denied the Company's motion on the basis that certain issues raised by the Company's motion were premature as the bankruptcy process had not yet established how much Calpine's creditors would receive. On November 5, 2007, the Company filed their answer, affirmative defenses and counterclaims with respect to the Lawsuit, denying the allegations set forth in both counts of the Lawsuit, and asserting affirmative defenses to Calpine's claims as well as affirmative counterclaims against Calpine related to the Acquisition for (i) breach of covenant of solvency, (ii) fraud and fraud in a real estate transaction, (iii) breach of contract, (iv) conversion, (v) civil theft and (vi) setoff. The parties are currently in agreement that discovery may continue in the Lawsuit until April 2008. The Bankruptcy Court has not set a trial date.

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Remaining Issues with Respect to the Acquisition

Separate from the Calpine lawsuit, Calpine has taken the position that 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”) are “executory contracts”, which Calpine may assume or reject. Following the July 7, 2005 closing of the Acquisition and as of the date of Calpine’s bankruptcy filing, there were open issues regarding legal title to certain properties included in the Purchase Agreement. On September 25, 2007, the Bankruptcy Court approved Calpine’s Disclosure Statement accompanying its proposed Plan of Reorganization under Chapter 11 of the Bankruptcy Code, in which Calpine revealed it had not yet made a decision as to whether to assume or reject its remaining duties and obligations under the Purchase Agreement. The Company may contend that the Purchase Agreement is not an executory contract which Calpine may choose to reject. If the Court were to determine that the Purchase Agreement is an executory contract, the Company may contend the various agreements entered into as part of the transaction constitute a single contract for purposes of assumption or rejection under the Bankruptcy Code, and the Company may argue that Calpine cannot choose to assume certain of the agreements and to reject others. This issue may be contested by Calpine. If the Purchase Agreement is held to be executory, the deadline by when Calpine must exercise its decision to assume or reject the Purchase Agreement and the further duties and obligations required therein would normally have been the date on which Calpine’s Plan of Reorganization was confirmed; however, in order to address certain issues, Calpine and the Company have agreed to extend this deadline until fifteen days following the entry of a final, unappealable order in the Lawsuit, and the parties set forth this agreement in the Plan of Reorganization approved by the Bankruptcy Court on December 19, 2007.

Open Issues Regarding Legal Title to Certain Properties

Under the Purchase Agreement, Calpine is required to resolve the open issues regarding legal title to interests in certain properties. At the closing of the Acquisition on July 7, 2005, the Company retained approximately $75 million of the purchase price in respect to leases and wells identified by Calpine as requiring third-party consents or waivers of preferential rights to purchase that were not received by the parties before closing (“Non-Consent Properties”). The interests in Non-Consent Properties were not included in the conveyances delivered at the closing. Subsequent analysis determined that a significant portion of the Non-Consent Properties did not require consents or waivers. For that portion of the Non-Consent Properties for which third-party consents were in fact required and for which either the Company or Calpine obtained the required consents or waivers, as well as for all Non-Consent Properties that did not require consents or waivers, the Company contends Calpine was and is obligated to have transferred to the Company the record 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. The Company has retained $7.1 million of the purchase price under the Purchase Agreement for the Non-Consent Properties subject to the third-party preferential right, and, in addition, a post-closing adjustment is required to credit the Company for approximately $0.3 million for a property which was transferred to it but, if necessary, will be transferred to the appropriate third party under its exercised preferential purchase right upon Calpine’s performance of its obligations under the Purchase Agreement.

The Company believes all conditions precedent for its 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 subject to the third-party preferential right) were satisfied earlier, and certainly no later, than December 15, 2005, when the Company tendered the amounts necessary to conclude the settlement of the Non-Consent Properties.

The Company believes it is the equitable owner of each of the Non-Consent Properties for which Calpine was and is obligated to have transferred the record title and that such properties are not part of Calpine’s bankruptcy estate. Upon the Company’s receipt from Calpine of record title, free of any mortgages or other liens, to these Non-Consent

Properties (excluding that portion of these properties subject to a validly exercised third party's preferential right to purchase) and further assurances required to eliminate any open issues on title to the remaining properties discussed below, the Company had been prepared to conclude the remaining aspects of the Acquisition. The Company has excluded from their statement of operations for the years ended December 31, 2007 and 2006 and six months ended December 31, 2005, estimated net revenues and estimated production from interests in certain leases and wells being a portion of the Non-Consent Properties, including those properties subject to preferential rights.

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On September 11, 2007, the Bankruptcy Court entered an order approving that certain Partial Transfer and Release Agreement ("PTRA") negotiated by and between the Company and Calpine which, among other things, resolves issues in regard to title of certain of the other oil and natural gas properties the Company purchased from Calpine in the Acquisition and for which payment was made to Calpine on July 7, 2005, and we entered into a new Marketing and Services Agreement ("MSA") with Calpine Producer Services, L.P. ("CPS") for a two-year period commencing on July 1, 2007 but which is subject to earlier termination by us on the occurrence of certain events. The additional documentation received from Calpine under the PTRA eliminates open issues in the Company's title and resolves any issues as to the clarity of the Company's ownership in certain properties located in the Gulf of Mexico, California, and Wyoming (the "PTRA Properties"), including all oil and gas properties requiring ministerial approvals, such as leases with the U.S. Minerals Management Service ("MMS"), California State Lands Commission ("CSLC") and U.S. Bureau of Land Management ("BLM"). However, the PTRA was executed without prejudice to Calpine's fraudulent conveyance action or its right, if any, to reject the Purchase Agreement, and without prejudice to the Company's rights and legal arguments in relation thereto, including the Company's various counterclaims. The PTRA did not otherwise address or resolve open issues with respect to the Non-Consent Properties and certain other properties.

The Company recorded the conveyances of those PTRA Properties in California not requiring governmental agency approval. On October 30, 2007, the CSLC approved the assignment of the State of California leases and rights of way to the Company from Calpine and resolved open issues under an audit the State of California had conducted as to these Properties. While the documentation has been filed with the MMS, the Company is still awaiting the ministerial approval for the assignment of Calpine's interests in MMS Federal Offshore leases for South Pelto 17 and South Timalier 252 to the Company.

Notwithstanding the PTRA, as a result of Calpine's bankruptcy filing, it remains uncertain as to whether Calpine will respond cooperatively as to the remaining outstanding issues under the Purchase Agreement. If Calpine does not fulfill its contractual obligations (as a result of rejection of the Purchase Agreement or otherwise) and does not complete the documentation necessary to resolve these remaining issues whether under the Purchase Agreement or the PTRA, 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 unlikely upon ultimate disposition, including appeals, if any, then the Company could experience losses which could have a material adverse effect on the Company's financial condition, statement of operations or cash flows.

Sale of Natural Gas to Calpine

In addition, the issues involving legal title to certain properties, the Company executed, as part of the interrelated agreements that constitute the Purchase Agreement, certain natural gas sales agreements with Calpine Energy Services, L.P. ("CES"), which also filed for bankruptcy on December 20, 2005. During the period following Calpine's filing for bankruptcy, CES 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 these various natural gas sales agreements. Although Calpine has indicated in a supplement to its recently proposed Plan of Reorganization that it intends to assume the CES natural gas sales agreements with the Company, the Company disagrees that Calpine may assume anything less than the entire Purchase Agreement and intends to oppose any effort by Calpine to do less.

Calpine's Marketing of the Company's Production

As part of the PTRA, the Company entered into the MSA with CPS, effective July 1, 2007, which was approved by the Bankruptcy Court on September 11, 2007. Under the MSA, CPS provides marketing and related services in relation to the sales of our natural gas production and charges the Company a fee. This MSA extends CPS' obligations to provide such services until June 30, 2009. The MSA is subject to early termination by the Company upon the occurrence of certain events.

Events within Calpine's Bankruptcy Case

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. The oil and gas leases identified in Calpine's motion are, in large part, those properties with open issues in regards to their legal title in certain oil and natural gas leases which Calpine contends it may possess some legal interest. According to this motion, Calpine filed its pending bankruptcy proceeding in order to avoid the automatic forfeiture of any interest it may have in these leases by operation of a bankruptcy code 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 that Calpine's motion 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. Certain of these properties have been subsequently addressed under the PTRA discussed above.

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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 MMS has subsequently recognized the Company as owner and operator of all but two of these properties, two other leases of offshore properties having expired, 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 could seek mediation to complete the following:

- Calpine's conveyance of its retained interests in 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.

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 CSLC 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 MMS) (the "MMS Oil and Gas Leases") and the State of California (and managed by the CSLC) (the "CSLC Leases"). Calpine, 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 (excluding the properties subject to third party's preferential right)..

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 have not presently been determined. In the event that Calpine elects to reject the Purchase Agreement or otherwise refuses to perform its remaining obligations therein, the Company anticipates it will be allowed to amend its proofs of claim to assert any additional damages it suffers as a result of the ultimate impact of Calpine's refusal or failure to perform under the Purchase Agreement. In the bankruptcy, Calpine may elect to contest or dispute the amount of damages the Company seeks in its proofs of claim. The Company will assert all rights to offset any of its damages against any funds it possess that may be owed to Calpine. Until the allowed amount of the Company's claims are finally established and the Bankruptcy Court issues its rulings with respect to Calpine's approved Plan of Reorganization, the Company cannot predict what amounts it may recover from the Calpine bankruptcy should Calpine reject or refuse to perform 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 and the CSLC Leases respectively, these parties further extended this deadline by stipulation. The deadline was first extended to January 31, 2007, 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, was further extended again to September 15, 2007 with respect to the MMS Oil and Gas Leases and July 15, 2007 and more recently, October 31, 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 the Company negotiated with Calpine for the Company's protection in this regard. The MMS Oil and Gas Leases and CSLC Leases were included in the PTRA that was approved by the Bankruptcy Court on September 11, 2007, with the result that there is no further need for the parties to contest whether the MMS Oil and Gas Leases and the CLSC Leases are appropriate for inclusion in Calpine's 365 motion. The PTRA approved by the Bankruptcy Court, among other things, resolves open issues in regard to the Company's title to ownership of all of the unexpired MMS Oil and Gas Leases and the CLSC Leases. However, the PTRA was executed without prejudice to Calpine's fraudulent conveyance action or its rights, if any, to reject the Purchase Agreement and the Company's rights and legal arguments in relation thereto.

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On June 20, 2007, Calpine filed its proposed Plan of Reorganization and Disclosure Statement with the Bankruptcy Court. Calpine had indicated in its filing with the Court that it believed substantial payments in the form of cash or newly issued stock, or some combination thereof, would be made to unsecured creditors under its proposed Plan of Reorganization that could conceivably result in payment of 100% of allowed claims and possibly provide some payment to its equity holders. The amounts any plan ultimately distributes to its various claimants of the Calpine estate, including unsecured creditors, will depend on the amount of allowed claims that remain following the objection process. The Bankruptcy Court approved Calpine's Plan of Reorganization on December 19, 2007, overruling the Company's objection to the releases granted by this Plan to prior and current directors and officers of Calpine and certain of its law firms and other professional advisors.

On August 3, 2007, the Company and Calpine executed the PTRA, resolving certain open issues without prejudice to Calpine's avoidance action and, if the Court concludes the Purchase Agreement is executory, Calpine's ability to assume or reject the Purchase Agreement. The principle terms are as follows:

- The Company extended certain marketing services by executing a new MSA with CPS through and until June 30, 2009, effective as of July 1, 2007. This agreement is subject to earlier termination rights by the Company upon the occurrence of certain events;

- Calpine delivers to the Company documents that resolve title issues pertaining to the Properties, defined as certain previously purchased oil and gas properties located in the Gulf of Mexico, California and Wyoming;

- The Company assumes all Calpine's rights and obligations for an audit by the California State Lands Commission on part of the Properties; and

- The Company assumes all rights and obligations for the Properties, including all plugging and abandonment liabilities.

On September 11, 2007, the Bankruptcy Court approved the PTRA. The PTRA did not resolve the open issues on the Non-Consent Properties and certain other properties.

As a result of Calpine's bankruptcy, there remains the possibility that there will be issues between the Company and Calpine that could amount to material contingencies in relation to the litigation filed by Calpine against the Company or 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 PTRA; and (iii) the issues pertaining to the Non-Consent Properties.

Arbitration between Calpine Corp./Rosetta 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 that 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. With Rosetta's assistance, 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 had earlier 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 stay this arbitration under the automatic stay provision of the Bankruptcy Code which motion was granted by the Bankruptcy Court on April 24, 2007. We intend to cooperate with Calpine in defending against Pogo's claim should it resume;

however, it is too early for management to determine whether this matter will affect the Company, and if so, in what amount. This is due, but not limited to uncertainty concerning (1) whether or not Pogo's proofs of claim will be fully satisfied by Calpine under its approved Plan of Reorganization; and (2) whether, and if so, the extent to which, Calpine may reimburse the Company for its claim for its defense costs and any arbitration award regarding the Pogo claim.

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 $2.6 million, $2.4 million and $ 0.6 million for the years ended December 31, 2007 and 2006 and for six months ended December 31, 2005, respectively. For the six months ended June 30, 2005 (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 for the six months ended June 30, 2005 (predecessor).

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Future minimum annual rental commitments under non-cancelable leases at December 31, 2007 are as follows (In thousands):

2008	2,365
2009	2,771
2010	2,684
2011	2,753
2012	2,782
Thereafter	3,063
	$ 16,418

The Company has drilling rig commitments of $4.1 million for 2008.

(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 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 Rosetta'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, Rosetta 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 years ended December 31, 2007 and 2006 was $6.8 million and $5.7 million, respectively, with an associated tax benefit of $2.5 million and $2.1 million, respectively. 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) stock-based compensation expense was $0.2 million with a tax benefit of $0.1million. The remaining unrecognized compensation expense associated with total unvested awards as of December 31, 2007 was $9.8 million.

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.

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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 majority of options generally vest over a three year period.

The weighted average fair value at date of grant for options granted during the years ended December 31, 2007 and 2006 and the six months ended December 31, 2005 was $ 9.51 per share, $ 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:

	Year Ended December 31, 2007	Year Ended December 31, 2006	Six Months Ended December 31, 2005
Expected option term (years)	6.5	6.5	6.5
Expected volatility	42.45%	56.65%	54.62%
Expected dividend rate	0.00%	0.00%	0.00%
Risk free interest rate	4.36% - 5.00%	4.33% - 5.15%	4.03% - 4.60%

The Company has assumed an annual forfeiture rate of 5% for the options granted in 2007 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, 2007:

	Shares	Weighted Average Exercise Price Per Share	Weighted Average Remaining Contractual Term (In years)	Aggregate Intrinsic Value (In thousands)
Outstanding at December 31, 2006	853,354	$ 16.80		
Granted	316,100	19.11		
Exercised	(40,104)	16.26		
Forfeited	(156,750)	17.60		
Outstanding at December 31, 2007	972,600	$ 17.45	8.22	$ 2,293
Options Vested and Exercisable at December 31, 2007	618,124	$ 17.25	8.13	$ 1,616

Stock-based compensation expense recorded for stock option awards for the years ended December 31, 2007 and 2006 was $3.9 million and $2.9 million, respectively. 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, 2007 for all outstanding stock options is $3.3 million and will be recognized over a weighted average period of 1.05 years.

The total intrinsic value of options exercised during the years ended December 31, 2007 and 2006 is $0.2 million and $0.1 million, respectively. There were no options exercised for the six months ended December 31, 2005.

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Restricted Stock

The Company has granted stock under its 2005 Long-Term Incentive Plan. The majority of restricted stock vests over a three year period. 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 related to restricted stock held by the Company's employees at December 31, 2007:

	Shares	Weighted Average Grant Date Fair Value
Non-vested shares outstanding at December 31, 2006	326,900	$ 17.05
Granted	315,350	19.48
Vested	(96,750)	16.95
Forfeited	(90,075)	18.34
Non-vested shares outstanding at December 31, 2007	455,425	$ 18.50

The non-vested restricted stock outstanding at December 31, 2007 generally 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 fair value of awards vested for the year ended December 31, 2007 was $2.0 million.

Stock-based compensation expense recorded for restricted stock awards for the years ended December 31, 2007 and 2006 and the six months ended December 31, 2005 was $2.9 million, $2.8 million and $4.2 million, respectively. Unrecognized expense as of December 31, 2007 for all outstanding restricted stock awards is $6.5 million and will be recognized over a weighted average period of 1.41 years.

(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, 2007, the Company had a deferred tax asset related to federal and state net operating loss carryforwards of approximately $33.1 million. Approximately $6.0 million of the net operating loss carryforward will expire in 2025. The remaining amount will begin to expire 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 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 against future taxable income recorded on deferred tax assets as the Company believes it is more likely than not that the asset will be utilized.

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The Company's income tax expense (benefit) consists of the following:

	Successor			Predecessor
	Year Ended December 31, 2007	Year Ended December 31, 2006	Six Months Ended December 31, 2005	Six Months Ended June 30, 2005
	(In thousands)			
Current:				
Federal	$ -	$ -	$ -	$ 7,556
State	115	172	-	1,067
	115	172	-	8,623
Deferred:				
Federal	31,979	24,132	10,139	2,519
State	1,938	3,340	1,398	354
	33,917	27,472	11,537	2,873
Total income tax expense (benefit)	$ 34,032	$ 27,644	$ 11,537	$ 11,496

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

	Successor						Predecessor	
	Year Ended December 31, 2007		Year Ended December 31, 2006		Six Months Ended December 31, 2005		Six Months Ended June 30, 2005	
	(In thousands)	(%)	(In thousands)	(%)	(In thousands)	(%)	(In thousands)	(%)
US Statutory Rate	$ 31,933	35.0%	$ 25,288	35.0%	$ 10,175	35.0%	$ 10,562	35.0%
Income/franschise tax, net of federal benefit	2,053	2.3%	2,283	3.2%	909	3.1%	924	3.1%
Transaction costs not deductible	-	0.0%	-	0.0%	466	1.6%	-	0.0%
Permanent differences and other	46	0.0%	73	0.0%	(13)	0.0%	10	0.0%
Total tax expense (Benefit)	$ 34,032	37.3%	$ 27,644	38.2%	$ 11,537	39.7%	$ 11,496	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. Future effective tax rates could be adversely affected if unfavorable changes in tax laws and regulations occur, or if the Company experiences future adverse determinations by taxing authorities.

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The components of deferred taxes are as follows:

	December 31, 2007	December 31, 2006
	(In thousands)	
Deferred tax assets		
Accrued liabilities not currently deductible	$ 3,273	$ 1,410
Hedge activity	4,289	-
Net operating loss carryforward	12,506	30,428
Other	892	413
Total deferred tax assets	20,960	32,251
Oil and gas basis differences	(89,397)	(71,142)
Hedge activity	-	(3,821)
Other	(200)	(120)
Total gross deferred tax liabilities	(89,597)	(75,083)
Net deferred tax assets (liabilities)	$ (68,637)	$ (42,832)

Accounting for Uncertainty in Income Taxes. In June 2006, the FASB issued FIN 48. FIN 48 requires that we recognize the financial statement benefit of a tax position only after determining that the relevant tax authority would more likely than not sustain the position following an audit. For a tax position meeting the more likely than not threshold, the amount recognized in the financial statements is the largest benefit that has a greater than 50% likelihood of being realized upon ultimate settlement with the relevant tax authority. As a result of the implementation of FIN 48, the Company did not have any unrecognized tax benefits and there was no effect on our financial condition or results of operations as a result of implementing FIN 48.

It is expected that the amount of unrecognized tax benefits may change in the next twelve months; however, the Company does not expect the change to have a significant impact on our financial condition or results of operations. As of December 31, 2007, the Company has no unrecognized tax benefits that if recognized would affect the effective tax rate.

The Company files income tax returns in the U.S. and in various state jurisdictions. With few exceptions, the Company is subject to US federal, state and local income tax examinations by tax authorities for tax periods 2005 and forward.

Estimated interest and penalties related to potential underpayment on any unrecognized tax benefits are classified as a component of tax expense in the consolidated statement of operations. The Company has not recorded any interest or penalties associated with unrecognized tax benefits.

(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 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	

	Year Ended December 31, 2007	December 31, 2006	Six Months Ended December 31, 2005	Six Months Ended June 30, 2005
			(In thousands)	
Basic weighted average number of shares outstanding	50,379	50,237	50,003	50,000
Dilution effect of stock option and awards at the end of the period	210	171	186	160
Diluted weighted average number of shares outstanding	50,589	50,408	50,189	50,160
Anti-dilutive stock awards and shares	385	198	-	-

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 Securities and Exchange Commission ("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.

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(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". Also, as all of our operations are located in the U.S., all of our costs are included in one cost pool. 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.

	Successor			Predecessor
	Year Ended December 31, 2007 (1)	Year Ended December 31, 2006 (1)	Six Months Ended December 31, 2005 (1)	Six Months Ended June 30, 2005
Oil and Natural Gas Revenue	(In thousands)			
California	$ 110,607	$ 76,408	$ 48,138	$ 43,385
Rocky Mountains	10,676	2,115	338	161
Mid-Continent	2,287	1,879	1,309	842
Lobo	117,368	71,450	39,062	26,474
Perdido	26,518	29,538	14,675	12,380
State Waters	8,789	8,183	6,761	2,345
Other Onshore	23,618	25,878	9,364	7,662
Gulf of Mexico	40,700	26,734	9,921	10,542
Other	-	-	112	40
	$ 340,563	$ 242,185	$ 129,680	$ 103,831

	December 31,	
	2007	2006
Oil and Natural Gas Properties	(In thousands)	
California	$ 540,924	$ 435,167
Rocky Mountains	76,343	44,455
Mid-Continent	14,698	9,584
Lobo	515,096	426,348
Perdido	76,259	52,702
State Waters	55,918	26,922
Other Onshore	130,977	102,734
Gulf of Mexico	155,867	125,425
Other	6,393	4,562
	$ 1,572,475	$ 1,227,899

(1) Excludes the effects of hedging gains of $22.9 million and $29.6 million for the years ended December 31, 2007 and 2006, respectively, and hedging losses of $16.6 million for the six months ended December 31, 2005. There was no hedging activity for the six months ended June 30, 2005.

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Major Customers

For the year ended December 31, 2007, the Company had one major customer, Calpine Energy Services ("CES"), a Calpine affiliate, which accounted for approximately 55% of the Company's consolidated annual revenue. The Company's annual consolidated revenue from CES accounted for approximately 45% for the year ended December 31, 2006 and 80% for the six months ended December 31, 2005, respectively, and is reflected in oil and natural gas sales.

For the years ended December 31, 2007 and 2006 and the six months ended December 31, 2005, revenues from sales to CES were $201.4 million, $99.1 million and $75.0 million, respectively. There was no receivable from CES at December 31, 2007 or 2006. For the six months ended June 30, 2005, revenues from sales to CES were $82.0 million. 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, 2007 and 2006, the Company had $20.4 million and $17.9 million in the margin account for December sales to CES which is included in other current liabilities on the Consolidated Balance Sheet.

Marketing Services Agreement

The Company entered into a new MSA with Calpine Producer Services ("CPS") in connection with the PTRA settlement on August 3, 2007 for the period July 1, 2007 through June 30, 2009, subject to earlier termination on the occurrence of certain events. The MSA covers a majority of 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 0.50%. For the years ended December 31, 2007 and 2006 and the six months ended December 31, 2005, the fee was approximately $2.5 million, $2.3 million and $1.4 million, 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) Related Party Transactions

Successor

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. LOTO II is indirectly owned in part by family trusts established by our director G. Louis Graziadio, III. 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.

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.

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.

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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, 2007, 2006, and 2005, 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 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.

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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, 2007 and 2006:

	Successor	
	2007	2006
	(In thousands)	
Proved properties	$ 1,499,046	$ 1,167,588
Unproved properties	40,903	37,813
Total	1,539,949	1,205,401
Less: Accumulated depreciation, depletion, and amortization	(291,321)	(143,216)
Net capitalized costs	$ 1,248,628	$ 1,062,185
Company's share of equity method investees' net capitalized costs	$ 1,198	$ 1,166

Pursuant to SFAS No. 143 “Accounting for Asset Retirement Obligations”, net capitalized cost includes asset retirement cost of $20.1 million and $9.6 million as of December 31, 2007 and 2006, 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 years ended December 31, 2007 and 2006 (Successor), six months ended December 31, 2005 (Successor) and June 30, 2005 (Predecessor):

	(In thousands)
Year Ended December 31, 2007 (Successor)	
Acquisition costs of properties	
Proved	$ 40,760
Unproved	23,824
Subtotal	64,584
Exploration costs	90,117
Development costs	178,894
Total	$ 333,595
Company's share of equity method investees' costs of property acquisition, exploration and development	$ 101
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	$ 61

development

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	(In thousands)
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
Company's share of equity method investees' costs of property acquisition, exploration and development	$ 181
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

Results of operations for oil and natural gas producing activities

		Successor		Predecessor
	Year Ended December 31, 2007	Year Ended December 31, 2006	Six Months Ended December 31, 2005	Six Months Ended June 30, 2005
Oil and natural gas producing revenues				
Third-party	$ 363,468	$ 271,751	$ 113,090	$ 21,803
Affiliate	-	-	-	81,952
Total Revenues	363,468	271,751	113,090	103,755
Exploration expenses, including dry hole	-	-	-	4,317
Production costs	60,140	47,507	22,314	22,295
Depreciation, depletion, and amortization	152,882	105,886	40,500	30,679
Income before income taxes	150,446	118,358	50,276	46,464
Income tax provision	56,041	44,621	19,155	17,656
Results of operations	$ 94,405	$ 73,737	$ 31,121	$ 28,808
Company's share of equity method investees' results of operations for producing activities	$ 415	$ 227	$ 241	$ 161

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, 2007, 2006, and 2005, 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 years ended December 31, 2007 and 2006 and six months ended December 31, 2005, and the item titled “Other” relates to estimated reserves for interests in certain leases and wells associated with the Non-Consent Properties.

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Natural gas (Bcf)(1):	
Net proved reserves at January 1, 2005 (Predecessor)	374
Revisions of previous estimates	(11)
Purchases in place	-
Extensions, discoveries and other additions	28
Sales in place	-
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) (6)	390
Revisions of previous estimates	(30)
Purchases in place	10
Extensions, discoveries and other additions	72
Sales in place	-
Production	(42)
Net proved reserves at December 31, 2007 (Successor) (6)	400
Company's proportional interst in reserves of investees' accounted for by the equity method - December 31, 2007 (Successor)	5

Natural gas liquids and crude oil (MBbl)(2)(3)	
Net proved reserves at January 1, 2005 (Predecessor)	2,611
Revisions of previous estimates	153
Purchases in place	108
Extensions, discoveries and other additions	(9)
Sales in place	-
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) (6)	2,930
Revisions of previous estimates	-
Purchases in place	-
Extensions, discoveries and other additions	652
Sales in place	-
Production	(561)
Net proved reserves at December 31, 2007 (Successor) (6)	3,021
Company's proportional interst in reserves of investees' accounted for by the equity method - December 31, 2007 (Successor)	-
Bcfe (1) equivalents (4)	
Net proved reserves at January 1, 2005 (Predecessor)	389
Revisions of previous estimates	(10)
Purchases in place	-
Extensions, discoveries and other additions	29
Sales in place	-
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) (6)	408
Revisions of previous estimates	(30)
Purchases in place	10
Extensions, discoveries and other additions	76
Sales in place	-
Production	(46)
Net proved reserves at December 31, 2007 (Successor) (6)	418
Company's proportional interst in reserves of investees' accounted for by the equity method - December 31, 2007 (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, 2005 (6)	223	1,320	231
December 31, 2006 (6)	251	1,965	263
December 31, 2007 (6)	286	2,658	302

(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) Estimated reserves pertaining to interests in certain leases and wells associated with the Non-Consent Properties.

(6) Excludes estimated reserves pertaining to interests in certain leases and wells associated with the 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, 2007, 2006 and 2005.

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		(In millions)
December 31, 2007		
Future cash inflows	$	3,026
Future production costs		(819)
Future development costs		(302)
Future net cash flows before income taxes		1,905
Future income taxes		(323)
Future net cash flows		1,582
Discount to present value at 10% annual rate		(628)
Standardized measure of discounted future net cash flows relating to proved natural gas, natural gas liquids and crude oil reserves	$	954
Company's share of equity method investee's standardized measure of discounted future net cash flows	$	2
December 31, 2006		
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
December 31, 2005		
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

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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, 2007, 2006 and 2005.

		(In millions)
Balance, January 1, 2005 (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)
Purchases of reserve in place		-
Sales of reserves in place		-
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
Sales and transfers of natural gas, natural gas liquids and crude oil produced, net of production costs		(303)
Net changes in prices and production costs		253
Extensions, discoveries, additions and improved recovery, net of related costs		283
Development costs incurred		92
Revisions of previous quantity estimates and development costs		(76)
Accretion of discount		79
Net change in income taxes		(113)
Purchases of reserve in place		38
Sales of reserves in place		-
Changes in timing and other		(21)
Balance December 31, 2007 (Successor) (1)	$	954

(1) Excludes non-consent properties

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Rosetta Reserouces Inc.
Selected Data
Quarterly Information
(Unaudited)

Summaries of the Company's results of operations by quarter for the years ended 2007 and 2006 are as follows:

	2007			
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(In thousands, except per share data)			
Revenues	$ 75,796	$ 86,874	$ 89,718	$ 111,101
Operating Income	25,969	25,317	24,415	30,898
Net Income	13,991	13,091	12,713	17,410
Basic earnings per share	$ 0.28	$ 0.26	$ 0.25	$ 0.35
Diluted earnings per share	$ 0.28	$ 0.26	$ 0.25	$ 0.34

	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

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

None

Item 9A. Controls and Procedures

Evaluation of 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, 2007. 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, 2007, our disclosure controls and procedures were effective.

Management’s Report on Internal Control Over Financial Reporting

Management, including our Chief Executive Officer and Chief Financial Officer, is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a – 15(f). Management conducted an assessment as of December 31, 2007 of the effectiveness of our internal control over financial reporting based on the framework in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (“COSO”). Based on that evaluation, management concluded that our internal control over financial reporting was effective as of December 31, 2007, based on criteria in Internal Control – Integrated Framework issued by the COSO.

The effectiveness of the Company’s internal control over financial reporting as of December 31, 2007, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which is included in Item 8 of this Annual Report on Form 10-K.

Changes in Internal Control Over Financial Reporting

There has been no change in our internal control over financial reporting during the quarter ended December 31, 2007 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

Item 9B. Other Information

In the fourth quarter of 2007, John M. Thibeaux, Michael H. Hickey and Edward E. Seeman entered into Amended and Restated Employment Agreements with the Company so that their employment agreements comply with the new tax provisions of the Internal Revenue Code Section 409A, which amendments are respectively attached hereto as Exhibits 10.36, 10.37 and 10.38.

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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 2008 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 2008 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 2008 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 2008 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 2008 annual meeting.

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Part IV

Item 15. Exhibits and Financial Statement Schedules

1. 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 53 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)).
10.14 †	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)).
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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 February 29, 2008.

ROSETTA RESOURCES INC.	
By:	/s/ Randy L. Limbacher Randy L. Limbacher, President and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, 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/ Randy L. Limbacher Randy L. Limbacher	President and Chief Executive Officer (Principal Executive Officer)	February 29, 2008
/s/ Michael J. Rosinski Michael J. Rosinski	Executive Vice President and Chief Financial Officer (Principal Financial Officer)	February 29, 2008
/s/ Denise D. Bednorz Denise D. Bednorz	Vice President, Controller (Principal Accounting Officer)	February 29, 2008
/s/ D. Henry Houston D. Henry Houston	Non-Executive Chairman, Director	February 29, 2008
/s/ Richard W. Beckler Richard W. Beckler	Director	February 29, 2008
/s/ Donald D. Patteson, Jr. Donald D. Patteson, Jr.	Director	February 29, 2008
/s/ G. Louis Graziadio, III G. Louis Graziadio, III	Director	February 29, 2008
/s/ Josiah O Low, III Josiah O Low, III	Director	February 29, 2008

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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.

Exploitation. Optimizing oil and gas production from producing properties or establishing additional reserves in producing areas through additional drilling or the application of new technology.

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.

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NYMEX. New York Mercantile Exchange.

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.”

Pay. A reservoir or portion of a reservoir that contains economically producible hydrocarbons. The overall interval in which pay sections occur is the gross pay; the smaller portions of the gross pay that meet local criteria for pay (such as a minimum porosity, permeability and hydrocarbon saturation) are net pay.

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 producing or is capable of production, including natural gas wells awaiting pipeline connections to commence deliveries and oil wells awaiting connection to production facilities.

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.

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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.

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

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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)).
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