Rosetta Resources Inc.
Form 10-K
March 02, 2009

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

FORM 10-K

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

For The Fiscal Year Ended December 31, 2008

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 Securities Act.
Yes £ No S

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

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. £

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.

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

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

The aggregate market value of the voting and non-voting common equity held by Non-affiliates of the registrant as of June 30, 2008 was approximately $1.5 billion based on the closing price of $28.50 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 20, 2009 was 52,131,612.

Documents Incorporated By Reference

Information required by Part III will either be included in Rosetta Resources Inc.'s definitive proxy statement relating to its 2009 annual meeting of stockholders 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 REGARDING FORWARD-LOOKING STATEMENTS

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, affects 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 of this Form 10-K. 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 77.

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 core areas of the Sacramento Basin of California, the Rockies, and South Texas. In addition, we have non-core positions in 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" or "Rosetta") 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. 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. We operate in one business segment. See Item 8. Financial Statements and Supplementary Data, Note 15 - Operating Segments.

Pursuant to the Acquisition, we entered into several operative contracts with Calpine. Currently, Calpine markets our oil and gas under a marketing services agreement ("Marketing Agreement"), whose term runs through June 30, 2009. We do not intend to extend or renew the Marketing Agreement upon expiration. 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 a purchase and sale agreement and all interrelated agreements, concurrently executed on or about July 7, 2005 (collectively, the "Purchase Agreement"), except the gas sales agreement for the dedicated California production which was amended and restated in connection with the parties' settlement agreement dated October 22, 2008 ("Settlement Agreement"). The Settlement Agreement, original gas purchase and sales contracts, the amended and restated gas purchase and sales contract for the dedicated California production, and the Marketing Agreement with Calpine are discussed further under Part I. Item 3. Legal Proceedings, "Calpine Settlement" and "Marketing and Customers."

Our Strategy

Our strategy is to increase stockholder value by executing a business model that delivers sustainable growth from unconventional onshore domestic basins. We believe this strategy is appropriate for and consistent with our longer-term view of the industry. However, we recognize that there may be cycles, such as the current economic downturn, that could impact our ability to execute this strategy fully on a short-term basis. Our strategy is multi-pronged and emphasizes (i) identifying and growing inventory in existing core properties, (ii) establishing new resource based core areas, (iii) ongoing efficient exploitation and exploration activities, (iv) completing acquisitions and selective divestitures, (v) maintaining technical expertise, (vi) focusing on cost control and (vii) maintaining financial flexibility. We seek to implement our strategy 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. Below is a discussion of the key elements of our strategy:

Developing and Extending Existing Core Properties. We have designated California, the Rockies and South Texas as core areas and intend to build our asset base in these areas through additional leasing and acquisitions where applicable. As importantly, we intend to further develop the upside potential of these core properties by conducting thorough resource assessments of our existing assets, working over existing wells, drilling in-fill locations, drilling step-out wells to expand known field outlines, testing and implementing downspacing potential, recompleting and testing behind pipe pays and lowering field line pressures through compression and optimization for additional reserve recovery.

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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.

Ongoing Efficient Exploitation and Exploration Activities. We intend to generate growth in existing and new core areas with exploitation and exploration inventory by efficiently applying technological and operational advantages through repeatable 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 with resource potential. We focus on opportunities with identified inventory where we believe our reservoir management and operational expertise will enhance the value and performance of the acquired properties through repeatable drilling programs. Periodically, we also evaluate possible divestitures of non-core 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 89% for the year ended December 31, 2008 and helped us maximize field recoveries. We 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, production, and inventory.

Focusing on Cost Control. We 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 activities within existing and new resource-based core areas where we can achieve efficiencies through economies of scale.

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, 2008, we had drawn $225.0 million and had $175.0 million available for borrowing under our revolving line of credit. Additionally, we expect internally generated cash flow to provide additional financial flexibility, allowing us to pursue our business strategy. We intend to 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 facility, we entered into natural gas fixed-price swaps for a portion of our expected production through 2010. As of December 31, 2008, 37% and 4% of our natural gas production was hedged using swaps and costless collars, respectively, with settlement in 2009, and 9% of our natural gas production was hedged with swaps for settlement in 2010. 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.

Calpine Settlement

On December 20, 2005, Calpine Corporation and certain of its subsidiaries filed for protection under the federal bankruptcy laws in the United States Bankruptcy Court of the Southern District of New York (the “Bankruptcy Court”). Two years later, on December 19, 2007, the Bankruptcy Court confirmed a plan of reorganization for Calpine, which emerged from bankruptcy on January 31, 2008. During that period, on June 29, 2007, Calpine commenced an adversary proceeding against the Company in the Bankruptcy Court (the “Lawsuit”). Over the next fourteen months, the Company vigorously disputed Calpine’s contentions in the Lawsuit, including any and all allegations that it underpaid for Calpine’s oil and gas business.

On October 22, 2008, Calpine and the Company announced that they had entered into a comprehensive settlement agreement (the “Settlement Agreement”) which, among other things, would (i) resolve all claims in the Lawsuit, (ii) result in Calpine conveying clean legal title on all remaining oil and gas assets to Rosetta (except those properties subject to the preferential rights of third parties who have indicated a desire to exercise their rights), (iii) settle all pending claims the Company filed in the Calpine bankruptcy, (iv) modify and extend a gas purchase agreement by which Calpine purchases the Company’s dedicated production from the Sacramento Valley, California, and (v) formalize the assumption by Calpine of the July 7, 2005 purchase and sale agreement (together with all interrelated agreements, the “Purchase Agreement”) by which Calpine’s oil and gas business was conveyed to the Company thus resulting in the parties honoring their obligations under the Purchase Agreement on a going-forward basis. The Settlement Agreement became effective when the Bankruptcy Court entered its order on November 13, 2008, authorizing the execution of the Settlement Agreement and the performance of the obligations set forth therein. No objections or appeals to this order were filed or taken with the Bankruptcy Court before or after the hearing on November 13, 2008, and it became final on or about November 23, 2008.

The parties completed this settlement pursuant to the terms of the Settlement Agreement on December 1, 2008. The cash component of the settlement consisted of $12.4 million payable in cash to Calpine to resolve all outstanding legal disputes regarding various matters, including Calpine’s fraudulent conveyance lawsuit. In addition, the Company paid $84.6 million under the Purchase Agreement to close the original acquisition transaction of the producing properties that were the subject of the lawsuit. This $84.6 million consisted of $67.6 million, which the Company withheld from the purchase price at the closing on July 7, 2005, related to non-consent properties (excluding the properties subject to preferential rights) that were not conveyed to the Company at closing on July 7, 2005, as well as $17.0 million for various disputed post-closing adjustments under the terms of the Purchase Agreement, as amended by the Bankruptcy Court order to remove the properties that had been subject to the Petersen Production Company (“Petersen”) preferential rights as if these properties had not been part of the Purchase Agreement.

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As a result of the conclusion of this settlement, the Company recorded a pre-tax charge of $12.4 million in the fourth quarter of 2008, which is included in Other Income (Expense) in the Consolidated Statement of Operations. See Item 8. Financial Statements and Supplementary Data, Note 11 – Commitments and Contingencies.

See Item 3. Legal Proceedings for further information regarding the final settlement with Calpine.

Arbitration between the Company and the successor to Pogo Producing Company

On October 27, 2008, the Company, Calpine and XTO Energy, Inc. (“XTO”), as the successor to Pogo Producing Company (“Pogo”), agreed to a Title Indemnity Agreement in which Calpine agreed to indemnify XTO for certain title disputes, and the Company, Calpine and XTO agreed to dismissal of the arbitration proceeding against the Company and release of Pogo’s proofs of claim. The Company’s proofs of claim were resolved under its Settlement Agreement with Calpine. XTO has dismissed with prejudice the arbitration against the Company.

Our Strengths

We believe our key strengths are as follows:

High Quality Asset Base. We own a geographically diversified asset base in key onshore hydrocarbon basins. Approximately 95% of our reserves are natural gas and almost all of our assets are located in the core areas of the Sacramento Basin of California, the Rockies, and South Texas. In addition, we have non-core positions in 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.

Resource Assessment Capability and Inventory Generation. We have established multi-disciplinary teams that are skilled at conducting comprehensive resource assessments on a field and regional basis. This work is the underpinning for indentifying and cataloging an inventory of low to moderate risk opportunities providing us with multiple years of drilling. At year end 2008, we had approximately 1,160 identified projects in inventory, up about 150% compared to year end 2007. This inventory, which includes proved undeveloped reserves, represents resources of about 575 Bcfe on a net unrisked basis and about 300 Bcfe on a net risked basis. We expect we will continue to add to our diversified portfolio of non-proved resource inventory over time.

Operational Control. We operate approximately 76% 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 28 years of experience in the energy industry with specific experience in the areas where our core properties are located. In November 2007, Randy L. Limbacher became our President and Chief Executive Officer (“CEO”). Mr. Limbacher has more than 28 years of experience in the energy industry, most recently serving as President, Exploration and Production - Americas for ConocoPhillips. Since coming to Rosetta, Mr. Limbacher has continued to hire experienced personnel with proven track records of success in the unconventional resource business.

Proven Technical and Land Personnel with Access to Technological Resources. Our technical staff includes 48 geologists, geophysicists, landmen, engineers and technicians with an average of over 15 years of relevant technical experience. Our staff has experience in 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 89%

for the year ended December 31, 2008 and 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.

Our Operating Areas

We own core producing and non-producing oil and natural gas properties in proven or prospective basins in California, the Rockies, South Texas, and various other geographical areas in the United States. We also have non-core positions in the State Waters of Texas and the Gulf of Mexico. In each area, we are pursuing geological objectives and projects that are consistent with our core strategy. For the year ended December 31, 2008, we have drilled 184 gross and 152 net wells, with a success rate of 89%. The following is a summary of our major operating areas.

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California

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 located near the Northern California natural gas markets and has an established natural gas gathering and pipeline infrastructure. We are one of the largest producers and leaseholders in the basin.

As of December 31, 2008, we owned approximately 69,000 net acres in the Rio Vista Field and Sacramento Basin areas. We believe our acreage in the basin holds significant low-risk, low-cost reserves, 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, 2008, our average net daily production from the Rio Vista Field and surrounding fields in the Sacramento Basin was 43.6 MMcfe/d. In 2008, we drilled 14 gross wells of which 13 were successful.

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 multiple 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, 2008, the average net daily production in the Rio Vista Field was approximately 39 MMcfe/d. We drilled 12 wells in the Rio Vista field in 2008; 11 of these were successful. Three wells drilled in the southern portion of the field were successful in extending areas in two reservoirs, the Lower Capay and the Martinez.

At December 31, 2008, we had one rig actively drilling in the field. There is one workover rig currently working on Rosetta wells in the Rio Vista area. We plan to conduct approximately 36 workovers, recompletions or reactivation operations on field wells during 2009. Moreover, a majority of 2009 time and effort will be devoted to resource assessments within the Rio Vista Gas Field. The evolution of the studies will generate the future drilling and recompletion inventory for 2010 and beyond.

Sacramento Valley Extension. We drilled two wells in the Sacramento Valley Extension area in 2008, both were successful. In 2009 we will continue to maintain operations through base optimization, selective recompletions, and asset rationalization.

Rockies

As of December 31, 2008, we owned approximately 173,000 net acres in the Rockies. Our production is concentrated in three basins: the DJ Basin, San Juan Basin and Greater Green River Basin. Our average net daily production for the year ended December 31, 2008 was 12.5 MMcfe/d. In 2008, we drilled 90 gross wells of which 84 were successful.

DJ Basin, Colorado. As of December 31, 2008, we had a majority working interest in 111,290 net acres with 154 square miles of 3D seismic data. In 2008, we drilled 76 locations, of which 70 were successful, and identified 500 additional drillable, 3D seismic supported locations on these lands. In addition, one salt water disposal well was drilled in 2008 and put into operation in the first quarter of 2009. For the year ended December 31, 2008, our average net daily production from the DJ Basin was 7.6 MMcfe/d. Successful delineation wells were drilled with newly acquired 3D seismic in Duke North, Duke, and Duke South that will add to the production already established in the Republican River, Vernon, SW Wray, and Sandy Bluffs areas.

San Juan Basin, New Mexico. The San Juan Basin is the second most prolific gas basin in North America with significant contribution coming from the Fruitland Coal Bed Methane ("CBM") trend. There is CBM production from depths of 1,600 feet surrounding our leasehold. As of December 31, 2008, we had a 100% working interest position in approximately 12,000 net acres. In May 2008, we purchased a 50% working interest position in approximately 12,000 gross acres from North American Petroleum Corporation USA, a subsidiary of Petroflow Energy Ltd. In 2008, we drilled 14 CBM wells, all of which were successful. For the year ended December 31, 2008, our average net daily production from the San Juan Basin was 4.3 MMcfe/d. We have identified 17 potential drillable locations on our acreage.

Pinedale, Wyoming. On December 11, 2008, we purchased a 90% working interest in 1,280 acres of the Pinedale field from Pinedale Energy LLC, a subsidiary of Constellation Energy Group, Inc. We purchased 28 productive natural gas wells and 1 salt water disposal well. We will study the field in 2009 for recompletion and downspacing potential. At year end, our average net daily production from Pinedale was 7.4 MMcfe/d.

Alberta Basin, Montana. The Alberta Basin play is a westward analog of the industry's Bakken and Three Forks of the Williston Basin of Montana and North Dakota. On December 24, 2008, Rosetta received approval from the Bureau of Indian Affairs to option approximately 200,000 net acres located on the Blackfeet Indian Reservation in Western Montana. Our plans for 2009 include detailed technical assessment, land consolidation, and drilling test wells.

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South Texas

As of December 31, 2008, we owned approximately 128,000 net acres in South Texas. Our production in South Texas comes primarily from the Lobo, Olmos, and Perdido sand trends, and averaged 54.5 MMcfe/d for the year ending December 31, 2008. In 2008 we drilled 69 gross wells of which 57 were successful. Additionally, we have acquired significant lease positions in two emerging resource play areas: the Dinn Sand trend and the Eagle Ford Shale trend.

Lobo Trend. We are a significant producer in the South Texas Lobo Trend, with 320 square miles of 3-D seismic and 255 operated producing wells. Our working interests range from 50% - 100%, but most of our acreage is 100% owned and operated. In 2008, we added additional acres adjacent to our existing acreage, adding additional drilling inventory. For the year ended December 31, 2008, our average net daily production from the Lobo trend was 46.1 MMcfe/d. We have identified approximately 170 potential drilling locations on our acreage. In 2008, we drilled 58 gross wells of which 48 were successful.

Discovered in 1973, the Lobo trend of South Texas is a complex, highly faulted sand that has produced over 8 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.

Olmos Trend. On December 23, 2008, we closed on the acquisition of a 70% non-operated working interest in 231 gross producing Olmos wells in the Olmos trend of South Texas. Production from these wells was approximately 5 MMcfe/d net at year end 2008.

Dinn Sand Trend. In 2008, we acquired a significant acreage position with approximately 100% operated working interest adjacent to our existing Perdido development trend. This leasehold acquisition has potential in the intermediate depth Dinn Sand trend. The Dinn Sand has been sparsely developed with vertical wells, and has potential for additional horizontal and vertical well development over most of the leasehold. Additionally, much of the leasehold has potential for extending the Perdido sand trend horizontal development from our adjacent non-operated 50% working interest acreage to this operated 100% working interest leasehold.

Eagle Ford Shale Trend. In 2008, we acquired several sizable acreage tracts with potential in the emerging shale gas play in the newly discovered Eagle Ford Shale trend. Along with acreage acquired in previous years, and the deep rights acquired with the Olmos production acquisition, we now have approximately 25,000 net acres in the Eagle Ford Shale trend. Most of this acreage also has potential in the Austin Chalk and Edwards formations.

Perdido Sand Trend. We own a 50% non-operated working interest 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. We plan to continue to coordinate with the operator to improve horizontal and vertical drilling techniques to lower cost and increase performance. For the year ended December 31, 2008, our average net daily production was 8.3 MMcfe/d from 37 producing wells (24 horizontal and 13 vertical). We participated in the drilling of seven gross wells in 2008, all of which were successful. We have identified approximately 60 potential drilling locations on our acreage.

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 well in Live Oak County, Texas in the fourth quarter of 2007 and tested the well in December 2007. The well was completed with first production commencing 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 41,000 net acres under lease with an average non-operated working interest of 47%.

Texas State Waters

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 2008, we drilled 4 gross wells, of which 3 were successful. Net production averaged 11.8 MMcfe/d during 2008. The field suffered some damage during Hurricane Ike in September 2008. Temporary repairs allowed bringing the wells back on line by October 2008, with permanent repairs to facilities and production equipment completed by year end. We currently hold interest in approximately 6,000 net acres with 70 square miles of 3-D seismic data.

Gulf of Mexico

Federal Waters. We own working interests in 12 offshore blocks ranging from 20% to 100% working interest with approximately 29,000 net acres. For the year ended December 31, 2008, our average net daily production from these blocks was 12 MMcfe/d.

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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, 2008		
	Natural Gas (Bcf)	Oil (MBbls)	Equivalents (Bcfe)
California	15.8	31.4	15.9
Rockies	4.5	6.1	4.6
South Texas	19.1	132.8	19.9
Other Onshore	3.6	128.9	4.4
Texas State Waters	3.5	143.5	4.4
Gulf of Mexico	3.8	103.7	4.4
	50.3	546.4	53.6

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, 2008, we had 398.2 Bcfe of proved oil and natural gas reserves, including 376.5 Bcf of natural gas and 3,603 MBbls of oil and condensate. Using prices as of December 31, 2008, the estimated standardized measure of discounted future net cash flows was $839 million. The following table sets forth, by operating area, a summary of our estimated net proved reserve information as of December 31, 2008:

	Estimated Proved Reserves at December 31, 2008 (1)			
	Developed (Bcfe)	Undeveloped (Bcfe)	Total (Bcfe)	Percent of Total Reserves
California	89.0	21.9	110.9	28%
Rockies	73.0	5.2	78.2	20%
South Texas	117.7	42.0	159.7	40%
Other Onshore	21.8	-	21.8	6%
Texas State Waters	9.9	-	9.9	2%
Gulf of Mexico	16.0	1.7	17.7	4%
Total	327.4	70.8	398.2	100%

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(1) These estimates are based upon a reserve report prepared by Netherland Sewell & Associates, Inc. (hereafter "Netherland Sewell"), independent petroleum engineers, using internally developed reserve estimates and criteria in compliance with the Securities and Exchange Commission ("SEC") guidelines. See Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations "Critical Accounting Policies and Estimates" and Item 8. Financial Statements and Supplementary Data "Supplemental Oil and Gas Disclosures."

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2008 Capital Expenditures

The following table summarizes information regarding development and exploration capital expenditures for the years ended December 31, 2008, 2007 and 2006:

	Year Ended December 31,		
	2008	2007	2006
		(In thousands)	
Capital Expenditures by Operating Area:			
California	$ 42,429	$ 58,493	$ 39,691
Rockies	25,015	23,904	15,299
South Texas	94,567	105,301	77,882
Other Onshore	12,927	29,796	13,578
Texas State Waters	8,541	27,000	13,028
Gulf of Mexico	422	28,523	17,958
Leasehold	17,883	8,838	16,383
Acquisitions	115,074	38,656	35,105
Delay rentals	1,451	1,409	728
Geological and geophysical/seismic	4,571	4,422	3,748
Total capital expenditures (1)	$ 322,880	$ 326,342	$ 233,400

(1) Capital expenditures for the year ended December 31, 2008 exclude capitalized internal costs directly identified with acquisition, exploration and development activities of $7.1 million, capitalized interest of $1.4 million and corporate other capital costs of $3.0 million. Capital expenditures for the year ended December 31, 2007 exclude 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 exclude capitalized internal costs of $3.4 million, capitalized interest of $2.1 million and corporate other capital 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.

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, 2008. "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		Developed Acres		Productive Wells (1)	
	Gross	Net	Gross	Net	Gross	Net
California	31,829	23,587	53,786	44,829	163	150
Rockies	167,227	143,709	37,105	28,667	249	216
South Texas	54,240	45,399	140,635	82,208	523	401
Other Onshore	33,065	21,317	55,128	19,881	304	51
Texas State Waters	5,706	2,709	9,978	3,259	8	2
Gulf of Mexico	7,500	5,000	41,994	24,386	7	5
	299,567	241,721	338,626	203,230	1,254	825

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

The following table shows our interest in undeveloped acreage as of December 31, 2008 which is subject to expiration in 2009, 2010, 2011, and thereafter.

2009		2010		2011		Thereafter	
Gross	Net	Gross	Net	Gross	Net	Gross	Net
36,617	31,249	63,476	53,145	89,151	70,184	110,323	87,143

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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
2008	3.0	1.0	4.0	160.0	20.0	180.0
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

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
2008	1.9	1.0	2.9	132.7	15.9	148.6
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

Marketing and Customers

Our amended and restated natural gas purchase and sales contract with Calpine Energy Services ("CES") dated as of October 22, 2008, for the dedicated California production was approved by the Bankruptcy Court and executed by the parties pursuant to the terms of the Settlement Agreement. The term of this amended and restated contract with CES runs through December 2019. The ten year right of first refusal provision, which was formerly part of this agreement, has been eliminated. Pursuant to the terms of this amended and restated contract with CES, 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. For the month of December 2008, this dedicated California production comprised approximately 29% of our current overall daily equivalent production.

Under the terms of this amended and restated contract with CES and our other spot natural gas purchase and sale agreements with Calpine, cash payment for all natural gas volumes that are contractually sold to CES 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 contracts, we are not obligated to continue to sell our production to CES and these sales may cease immediately. We would then be in a position to market this natural gas production to other parties. CES has 60 days to pay amounts owed to us, at which time, provided CES has fully cured such payment default, we are obligated under the contract to resume natural gas sales to CES. We believe that Calpine's bankruptcy and their emergence from bankruptcy have not had a significant effect on our ability to sell our natural gas at market prices.

We may market our natural gas production in California, which is not subject to this amended and restated contract with CES, to parties other than Calpine. All of our other production (other than our dedicated California production being sold pursuant to this amended and restated contract with CES at market pricing) is sold to various purchasers, including CES, on a competitive basis. Additionally, Calpine Producer Services, L.P., an affiliate of Calpine Corporation, is under contract through June 30, 2009 to provide us with administrative services in connection with our marketing efforts for all of our oil and gas production in accordance with the contract terms. We do not intend to extend or renew this marketing contract upon expiration, rather we intend to market all of our oil and gas production ourselves at the conclusion of this contract and our expanding our internal capabilities in this regard.

Major Customers

For the year ended December 31, 2008, we had one major customer, CES, which accounted for, on an aggregate basis, approximately 61% 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 than we do. 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. 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 legislation 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 material 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 types of legislation affecting our business.

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 stringent federal, state and local statutes, rules and regulations concerning occupational safety and health and protection of wildlife habitat and the natural environment. We have made and will continue to make expenditures in our efforts to comply with these requirements. At December 31, 2008, these estimated future expenditures for environmental control facilities were not material. In this regard, we believe that we currently hold all up-to-date permits, registrations and other authorizations to the extent they are required of 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 unavailable 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. We carry limited property insurance for loss or damage caused by earthquakes, and our energy package insurance, including property insurance, is limited to $15 million in the aggregate for any single named windstorm with a $1 million retention.

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 2008, we filed estimates of our oil and gas reserves as of December 31, 2007 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, 2007. For information concerning proved natural gas and crude oil reserves, refer to Item 8. Financial Statements and Supplementary Data, Supplemental Oil and Gas Disclosures.

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Employees

As of February 20, 2009, we have 186 full time employees. We also contract for the services of consultants involved in land, regulatory, accounting, financial, legal and other disciplines as needed. As of February 20, 2009, we have contracted approximately 45 independent consultants. 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.

Available Information

Through our website, http://www.rosettaresources.com, you can access, free of charge, our filings with the SEC, including our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Exchange Act, our Code of Business Conduct and Ethics, Nominating and Corporate Governance Committee Charter, Audit Committee Charter, and Compensation Committee Charter. You may also read and copy any materials that we file with the SEC at the SEC's Public Reference Room at 100 F Street, NE, Room 1580, Washington, D.C. 20549. You may obtain information on the operation of the Public Reference Room 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 http://www.sec.gov.

Item 1A. Risk Factors

Broad industry or economic factors may adversely affect the timing of and extent to which the Company can effectively implement its strategy shift to an onshore unconventional resource player.

Our strategy shift is an important element of positioning the Company for more predictable, sustainable future performance. In conjunction with pursuing this shift, the Company recognizes that several factors could impact our ability to execute the shift, including: (i) a sustained downturn of commodity prices, (ii) a lack of inventory potential within existing assets, (iii) an inability to attract and retain the personnel necessary to implement an unconventional resource business model, and (iv) a lack of access to credit. The Company has processes in place to track and monitor these trends on an ongoing basis. At this time, the Company believes the rationale and the goals for the strategy shift are intact; however, current market conditions could impact the pace of the planned shift.

Recent changes in the financial and credit markets may impact economic growth and oil and gas prices may continue to be adversely affected by general economic conditions.

Based on a number of economic indicators, it appears that growth in global economic activity has slowed substantially. At the present time, the rate at which the global economy will slow has become increasingly uncertain. A continued slowing of global economic growth, and access to credit markets, and, in particular, in the United States or China, will likely continue to reduce demand for oil and natural gas. A reduction in the demand for and the resulting lower prices of oil and natural gas could adversely affect our results of operations.

The current deterioration in the credit markets, combined with a decline in commodity prices, may impact our capital expenditure level and also our counterparty risk.

While we seek to fund our capital expenditures primarily from cash flows from operating activities, we have in the past also drawn on unused capacity under our existing revolving credit facility for capital expenditures. While we have not received any indication from our lenders that our ability to draw on our existing revolving credit facility has been restricted, it is possible that our borrowing base, which is based on our oil and gas reserves and is subject to review and adjustment on a semi-annual basis, with the next review scheduled to begin on March 2, 2009, and other interim adjustments, may be reduced when it is reviewed. In the event that our borrowing base is reduced, outstanding borrowings in excess of the revised base will be due immediately. As we do not have a substantial amount of unpledged property, we may not have the financial resources to make the mandatory prepayments. A reduction in our ability to borrow under our existing revolving credit facility, combined with a reduction in cash flow from operating activities resulting from a decline in commodity prices, may require us to reduce our capital expenditures further, which may in turn adversely affect our ability to carry out our business plan and execute our programs. Furthermore, if we lack the resources to dedicate sufficient capital expenditures to our existing oil and gas leases, we may be unable to produce adequate quantities of oil and gas to retain these leases and they may expire due to a lack of production. The loss of a sufficient number of leases could have a material adverse effect on our results of operations.

Additionally, while we believe that our existing production is adequately hedged with credit worthy counterparties, continued deterioration in the credit markets may impact the credit ratings of our current and potential counterparties and affect their ability to fulfill their existing obligations to us and their willingness to enter into future transactions with us.

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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. Additionally, our results are subject to commodity price fluctuations related to seasonal and market conditions and reservoir and production risks.

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;

– Technological advances affecting oil and natural gas consumption;

– Overall U.S. and global economic conditions;

– Price and availability of alternative fuels;

– Seasonal variations in oil and natural gas prices;

– Variations in levels of production; and

– The completion of exploration and production projects.

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 continued weakness 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;

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– 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. Recent deterioration in overall economic conditions and tightening of credit markets may increase the risk that contractual counterparties may fail to perform. Further deterioration in economic conditions in 2009 could result in an even greater risk of non-performance by market participants including our counterparties which could further impact our financial position.

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

In connection with the Acquisition and now the Settlement Agreement, we have entered into an amended and restated natural gas purchase and sale contract with CES whose term runs through December 2019. Under this amended and restated contract with CES, 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. For the month of December 2008, this dedicated California production comprised approximately 29% of our current overall production based on an equivalent unit 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 amended and restated contract with CES and spot agreements with CES, all natural gas volumes that are contractually sold to CES are collateralized by CES 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 CES, we could be exposed to the loss of up to four days of natural gas sales revenue under these contracts, which at prices and volumes in effect as of December 31, 2008 would be approximately $2.5 million.

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

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

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

Future projects and acquisitions 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. If we are unable to comply with these covenants, our lenders could accelerate the repayment of our indebtedness.

The terms of our credit facilities subject us to a number of covenants that impose restrictions on us, including our ability to incur indebtedness and liens, make loans and investments, make capital expenditures, sell assets, engage in mergers, consolidations and acquisitions, enter into transactions with affiliates, enter into sale and leaseback transactions, change our lines of business and pay dividends on our common stock. We will also be required by the terms of our credit facilities to comply with financial covenant ratios. A more detailed description of our credit facilities is included in Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources and the footnotes to the Consolidated Financial Statements.

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

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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
- 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. 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, independent petroleum engineers Netherland Sewell's reserve report for year end 2008 includes the downward revision of 64 Bcfe of proved reserves and 8 Bcfe due to year-end commodity prices, or approximately 17% of previously estimated reserves. 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. Our reserves as of December 31, 2008 were based on West Texas Intermediate oil prices of $41.00 per Bbl and Henry Hub gas prices of $5.71 per MMbtu compared to $92.50 and $6.80, respectively, at December 31, 2007. Actual future prices and costs fluctuate over time and may differ materially from those used in the present value estimate. In addition, discounted future net cash flows are estimated assuming royalties to the MMS, royalty owners and other state and federal regulatory agencies with respect to our affected properties, and will be paid or suspended during the life of the properties based upon oil and natural gas prices as of the date of the estimate. Since actual future prices fluctuate over time, royalties may be required to be paid for various portions of the life of the properties and suspended for other portions of the life of the properties.

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

We are subject to the full cost ceiling limitation which has resulted in a write-down of our estimated net reserves and may result in a write-down in the future if commodity prices continue to decline.

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. 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, a 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.

For the year ended December 31, 2008, we recognized a non-cash, pre-tax ceiling test impairment of $205.7 million and $238.7 million in the third and fourth quarters of 2008, respectively. Due to the volatility of commodity prices, should natural gas prices continue to decline in the future, it is possible that an additional write-down could occur.

In addition, write-downs of proved oil and natural gas properties may occur if we experience substantial downward adjustments to our estimated proved reserves. For example, we recognized a downward revision to our proved reserves in the third and fourth quarters of 2008. As we are continuing to evaluate and test our asset base, it is possible that we may recognize additional revisions to our proved reserves in the future.

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 upon 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.

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The ultimate outcome of any 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. 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.

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. If oil and gas prices increase in the future, increasing levels of exploration and production could result in response to these stronger prices, and as a result, the demand for oilfield services could rise, and the costs of these services could increase, 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;

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- 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 could 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.

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;
- Ability or impediments to conducting thorough due diligence activities;
- 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 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;
- Availability of required performance bonds and insurance;
- Oil field service costs and availability;
- Compliance with environmental and other laws and regulations;
- Remediation and other costs resulting from oil spills or releases of hazardous materials; and
- Failure of equipment or facilities.

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

Hedging transactions may limit our potential gains, result in financial losses or reduce our income .

We have entered into natural gas price hedging arrangements with respect to a portion of our expected production through 2010. As of December 31, 2008, 37% and 4% of our natural gas production was hedged using swaps and costless collars, respectively, with settlement in 2009, and 9% of our natural gas production was hedged with swaps for settlement in 2010, based on anticipated future gas production. 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. Our current hedge positions are with counterparties that are lenders in our credit facilities. Our lenders are comprised of banks and financial institutions that could default or fail to perform under our contractual agreements. A default under any of these agreements could negatively impact our financial performance.

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 may not receive the benefit of the lower interest rates.

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, 2008, 51,748,920 shares of common stock were issued, including 1,434,430 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, 716,991 shares had vested as of December 31, 2008 and the remaining shares will vest no later than 2012. Pursuant to our amended 2005 Long-Term Incentive Plan, we have reserved 4,950,000 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 1,245,875 options to purchase common stock issued to certain employees and directors, of which 304,119 have been exercised as of December 31, 2008. 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.

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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 and lease a third floor. 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.

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 interfere with our use of the properties in the operation of our business.

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.

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 Settlement

On December 20, 2005, Calpine filed for protection under the federal bankruptcy laws. Two years later, on December 19, 2007, the Bankruptcy Court confirmed a plan of reorganization for Calpine, which emerged from bankruptcy on January 31, 2008. During that period, on June 29, 2007, Calpine commenced the Lawsuit. Over the next fourteen months, the Company vigorously disputed Calpine's contentions in the Lawsuit, including any and all allegations that it underpaid for Calpine's oil and gas business.

On October 22, 2008, Calpine and the Company announced that they had entered into the Settlement Agreement which, among other things, would (i) resolve all claims in the Lawsuit, (ii) result in Calpine conveying clean legal title on all remaining oil and gas assets to Rosetta (except those properties subject to the preferential rights of third parties who have indicated a desire to exercise their rights), (iii) settle all pending claims the Company filed in the Calpine bankruptcy, (iv) modify and extend a gas purchase agreement by which Calpine purchases the Company's dedicated production from the Sacramento Valley, California, and (v) formalize the assumption by Calpine of the July 7, 2005 purchase and sale agreement (together with all interrelated agreements, the "Purchase Agreement") by which Calpine's oil and gas business was conveyed to the Company thus resulting in the parties honoring their obligations under the Purchase Agreement on a going-forward basis. The Settlement Agreement became effective when the Bankruptcy Court entered its order on November 13, 2008, authorizing the execution of the Settlement Agreement and the performance of the obligations set forth therein. No objections or appeals to this order were filed or taken with the Bankruptcy Court before or after the hearing on November 13, 2008, and it became final on or about November 23, 2008.

The parties completed this settlement pursuant to the terms of the Settlement Agreement on December 1, 2008. The cash component of the settlement consisted of $12.4 million payable in cash to Calpine to resolve all outstanding legal disputes regarding various matters, including Calpine's fraudulent conveyance lawsuit. In addition, the Company paid $84.6 million under the Purchase Agreement to close the original acquisition transaction of the producing properties that were the subject of the lawsuit. This $84.6 million consisted of $67.6 million, which the Company withheld from the purchase price at the closing on July 7, 2005, related to non-consent properties (excluding the properties subject to the Petersen preferential rights) that were not conveyed to the Company at closing on July 7, 2005, as well as $17.0 million for various disputed post-closing adjustments under the terms of the Purchase Agreement, as amended by the Bankruptcy Court order to remove the properties that had been subject to the Petersen preferential rights, as if these properties had not been part of the Purchase Agreement.

As a result of the conclusion of this settlement, the Company recorded a pre-tax charge of $12.4 million in the fourth quarter of 2008, which is included in Other Income (Expense) in the Consolidated Statement of Operations.

Arbitration between the Company and the successor to Pogo Producing Company

On October 27, 2008, the Company, Calpine and XTO, as the successor to Pogo, agreed to a Title Indemnity Agreement in which Calpine agreed to indemnify XTO for certain title disputes, and the Company, Calpine and XTO agreed to dismissal of the arbitration proceeding against the Company and release of Pogo's proofs of claim. The Company's proofs of claim were resolved within the framework of the Settlement Agreement with Calpine, which was approved by the Bankruptcy Court and an order issued in this regard. XTO has dismissed with prejudice the arbitration against the Company.

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 2008.

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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.

The following table sets forth for the 2008 and 2007 periods indicated the high and low sale prices of our common stock:

2008	High	Low	2007	High	Low
January 1 - March 31	$ 21.42	$ 16.20	January 1 - March 31	$ 21.07	$ 17.66
April 1 - June 30	29.65	19.15	April 1 - June 30	25.00	20.74
July 1 - September 30	29.20	16.67	July 1 - September 30	21.97	15.67
October 1 - December 31	18.23	5.97	October 1 - December 31	20.84	17.69

The number of shareholders of record on February 24, 2009 was approximately 10,700. 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. Our Senior Secured Revolving Line of Credit agreement restricts our ability to pay cash dividends on our common stock. See Item 8. Financial Statements and Supplementary Data Note 10 – Long-Term Debt.

The following table sets forth certain information with respect to repurchases of our common stock during the three months ended December 31, 2008:

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	2,563	$ 12.71	-	-

November 1 - November 30	1,669	10.02	-	-
December 1 - December 31	82	6.99	-	-

(1) All of the shares were surrendered by our 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 performance graph and related information shall not be deemed "soliciting material" or to be "filed" with the Securities and Exchange Commission, nor shall such information be incorporated by reference into any future filing under the Securities Act of 1933 or Securities Exchange Act of 1934, each as amended, except to the extent that the Company specifically incorporates it by reference into such filing.

The following common stock performance graph shows the performance of Rosetta Resources Inc. common stock up to December 31, 2008. As required by applicable rules of the Securities Exchange Commission, the performance graph shown below was prepared based on the following assumptions:

- A $100 investment was made in Rosetta Resources Inc. common stock at the opening trade price of $19.00 per share on February 13, 2006 (the first full trading day following the Company's initial public offering of its common stock), and $100 was invested in each of the Standard & Poor's 500 Index (S&P 500), a selected Peer Group (described below), and the Standard & Poor's MidCap 400 Oil & Gas Exploration & Production Index (S&P 400 E&P) at the closing price on February 10, 2006.
- All dividends are reinvested for each measurement period.

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The seven companies that comprise the selected 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). In 2008, we changed from using a selected Peer Group to the S&P 400 E&P Index because this published index is widely recognized in our industry and includes a representative group of independent peer companies (weighted by market capital) that are engaged in comparable exploration, development and production operations. In the future, we will not include the Peer Group in our analysis.

Total Return Among Rosetta Resources Inc., the S&P 500 Index, the S&P 400 O&G E&P Index, and our Peer Group

	2/13/2006 (1)	12/31/2006	12/31/2007	12/31/2008
ROSE	$ 100.00	$ 98.26	$ 104.37	$ 37.26
Peer Group	$ 100.00	$ 98.01	$ 148.08	$ 105.67
S&P 500	$ 100.00	$ 111.94	$ 115.89	$ 71.29
S&P400 O&G E&P	$ 100.00	$ 103.01	$ 148.46	$ 67.48

(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, 2008, 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 year ended December 31, 2004 (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 Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations and the audited Consolidated Financial Statements and related notes included elsewhere in this Form 10-K.

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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.

	Successor-Consolidated				Predecessor - Combined	
	Year Ended December 31,			Six Months Ended December 31,	Six Months Ended June 30,	Year Ended December 31,
	2008 (2)	2007	2006	2005	2005	2004 (1) (2)
	(In thousands, except per share data)					
Operating Data:						
Total revenue	$ 499,347	$ 363,489	$ 271,763	$ 113,104	$ 103,831	$ 248,006
Income (loss) from continuing operations	(188,110)	57,205	44,608	17,535	18,681	(78,836)
Net income (loss)	(188,110)	57,205	44,608	17,535	18,681	(10,396)
Income (loss) per share:						
Income (loss) from continuing operations						
Basic	(3.71)	1.14	0.89	0.35	0.37	(1.58)
Diluted	(3.71)	1.13	0.88	0.35	0.37	(1.58)
Net income (loss)						
Basic	(3.71)	1.14	0.89	0.35	0.37	(0.21)
Diluted	(3.71)	1.13	0.88	0.35	0.37	(0.21)
Cash dividends declared per common share	-	-	-	-	-	-
Balance Sheet Data (At the end of the Period)						
Total assets	1,154,378	1,357,214	1,219,405	1,119,269	-	656,528
Long-term debt	300,000	245,000	240,000	240,000	-	-
Stockholders' equity/owner's net investment	726,372	872,955	822,289	715,423	-	223,451

(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 $444.4 million and a $202.1 million non-cash, pre-tax impairment charge for the years ended December 31, 2008 and 2004, respectively.

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

Overview

Rosetta has delivered production growth by executing a business model based predominantly upon conventional exploration and exploitation. The Company actively pursued opportunities in conventional basins and plays characterized by higher decline rates. In early 2008, we began a strategic shift toward a business model that we believed could generate more sustainable, predictable performance over time. Accordingly, we have been on a path to de-emphasize high-decline rate, conventional programs in the Gulf of Mexico and Texas State Waters, while focusing on building positions and programs in unconventional onshore domestic basins. These basins are characterized by having lower hydrocarbon risk project inventory and repeatable programs, which the Company believes can generate more sustainable, predictable results. Consistent with the nature of unconventional resources, we would expect annual production growth rates to moderate compared to historical production growth rates as we shift to more resource-driven projects and focus on drilling inventory generation. Our strategy shift will be accompanied by goals to deliver, over time, both acceptable rates of production growth, as well as growth in proved, probable and possible reserves in excess of historical performance. The timing of and extent to which we can implement this strategy shift will depend on several factors, most notably commodity prices and access to credit.

Under more typical price scenarios, we believe we can successfully implement our strategy shift because of some inherent strengths. Of note, we believe our core existing onshore assets have upside that has not been fully analyzed through an unconventional resource lens. We think this approach could yield additional inventory for the Company over time. In addition, we have an experienced workforce and management team with background in unconventional resource operations. Finally, we have a financial and capital allocation approach that we believe allows us to adapt to the inevitable industry cycles and the current economic downturn. These factors do not ensure our success in executing our strategy shift, but we believe they provide a competitive advantage towards executing our strategy shift over the longer term.

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Our plan for implementing the strategy shift that is underway is to pursue, over time, both organic and inorganic opportunities that meet Rosetta's criteria for funding, particularly inventory potential and attractive financial returns. In 2008, we began several studies to test organic concepts in areas where we currently have assets for the purpose of identifying possible upside and inventory. We also began studying new domestic basins where we believe Rosetta can compete successfully. While we have a preference for organic opportunities, we are also expanding our capability to evaluate and pursue acquisition opportunities that make sense for Rosetta. We believe this balanced approach is needed for long-term success; however, it is not our intention or desire to pursue acquisitions solely for the sake of growth. Our ability to execute organic and inorganic activities will depend on market conditions.

On October 22, 2008, we signed the Settlement Agreement with Calpine. This settlement resolved all disputes between the parties, whether relating to the oil and gas property purchase, Rosetta's proofs of claim in the bankruptcy and its counter claims, or otherwise and was recorded as a pre-tax charge to income in the amount of $12.4 million. In addition, we paid $84.6 million to close the original 2005 acquisition transaction of the producing properties that were the subject of the Lawsuit. This $84.6 million consisted of $67.6 million which we withheld from the purchase price related to properties that were not conveyed to Rosetta, as well as $17.0 million for post-closing adjustments.

During 2008, our technical teams conducted a comprehensive review of several detailed field studies. Based upon these studies, and in coordination with our independent reserve engineers, we recognized a downward revision of 64 Bcfe of proved reserves, or approximately 15% of previously estimated reserves. We believe that our year-end reserves reflect our comprehensive updated technical view of field performance. In addition, we recognized 8 Bcfe of downward revisions due to year-end commodity prices and a cumulative non-cash ceiling test impairment charge of $444.4 million on a pre-tax basis, and $278.9 million net of tax.

With the Calpine Settlement and known reserve revisions behind us, we enter 2009 in a position to execute our business plan and effect our desired goals, subject to economic and market factors. We believe that we now have greater operating control and latitude over critical activities, such as rationalizing our portfolio, attracting technical talent, pursuing acquisitions that fit our strategy, and building sustainable project inventory. Our preliminary 2009 capital spending budget of $250 million was announced in the fourth quarter of 2008. At that time, we indicated that we believed the program could be funded internally at an average gas price of $7 per Mcf. We also indicated that we could expect to maintain annual production volumes in the range of 140 – 150 MMcfe/day for that level of spending. Given the current pervasive commodity price and economic downturn, our capital spending and production guidance are in flux. The priority for our 2009 organic spending is to spend within our internally generated cash flow in order to preserve our liquidity and retain flexibility. We expect our capital spending level to be significantly reduced compared to our preliminary budget. At this time, we intend to curtail our organic drilling programs, while testing several new play concepts, notably in the Bakken Shale in the Alberta Basin and the Eagle Ford Shale in South Texas. We have the discretion to adjust capital spending plans throughout the year in response to market conditions and the availability of proceeds from possible divestitures. These adjustments could include shutting down our core area drilling programs until such time as services costs contract and/or commodity prices recover. We will actively monitor our spending throughout the year. Our goal is to be financially prudent; however, our capital decisions could significantly impact targets and performance. Given the uncertainty in our capital program, it is not practical to provide production guidance at the outset of 2009. However, it is likely that, at current prices, our capital spending level would not be sufficient to grow production or reserves organically.

We recognize that we are operating in one of the most challenging business environments in recent history and that the credit crisis, declining oil prices, lower natural gas prices and a weakening global economic outlook are all adversely impacting the business environment. We are working with our lenders to effectively stay abreast of market and creditor conditions to ensure prudent and timely decisions should market conditions deteriorate further. We believe that we have sufficient liquidity and operational flexibility to fund and actively manage a prudent capital expenditures program, including, but not limited to, capping these expenditures in an annual period to the cash flows available from operating activities. We may also undertake divestitures to generate cash and exit non-core areas. Also of note, our capital expenditures are primarily in areas where Rosetta acts as operator and has high working interests. As a result, we do not believe we have significant exposure to joint interest partners who may be unable to fund their portion of any capital program, but we are monitoring partner situations in light of the current economic environment. We are actively working with service companies and suppliers to mitigate costs, and we are examining all cash costs for improved efficiency.

To the extent that capital expenditures or prudent acquisitions require cash flow in excess of available funds, we would consider drawing on our unused capacity under our existing revolving credit facility. As of December 31, 2008, the undrawn credit available to us was $175.0 million. We have not received any indication from our lenders that draws under the credit facility are restricted below current availability at this time and we are proactively communicating with them on a routine basis. We affirmed our borrowing base in the third quarter of 2008 at $400.0 million and the next redetermination is to begin in March 2009. Our plan is to extend the term of our revolving credit facility in the first half of 2009.

Finally, with respect to the current market environment for liquidity and access to credit, the Company, through banks participating in its credit facility, has invested available cash in money market accounts and funds whose investments are limited to United States Government Securities, securities backed by the United States Government, or securities of United States Government agencies. The Company followed this policy prior to the recent changes in credit markets, and believes this is an appropriate approach for the investment of Company funds in the current environment.

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All counterparties to our derivative instruments are participants in our credit facilities, and we have not received any indication that any of these counterparties are unable to perform their required obligations under the terms of the derivative contracts, although we are mindful that this could change and we are staying alert for such changes. Similarly, we have not received any indication that any of the banks participating in the existing bank facility are not capable of performing their obligations under the terms of the credit agreement.

Financial Highlights

Our consolidated financial statements reflect total revenue of $499.3 million on total volumes of 53.6 Bcfe for the year ended December 31, 2008. Operating loss was $275.3 million, or (55%) of total revenue, and included depreciation, depletion and amortization expense of $198.9 million, a non-cash, pre-tax full cost ceiling test impairment charge of $444.4 million, lease operating expense of $55.7 million and $7.2 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 and $12.4 million of litigation expense related to the Calpine Settlement, offset by interest income on short-term cash investments.

Critical Accounting Policies and Estimates

The discussion and analysis of our financial condition and results of operations are based upon the Consolidated 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. 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. Financial Statements and Supplementary Data, Note 2 - Summary of Significant Accounting Policies, for a discussion of additional accounting policies and estimates made by management.

Principles of Consolidation

The accompanying consolidated financial statements as of December 31, 2008, 2007 and 2006, contain the accounts of the Company and its majority owned subsidiaries after eliminating all significant intercompany balances and transactions.

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 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.

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, since we generally reflect a higher level of capitalized costs as well as a higher depreciation, depletion and amortization rate on our oil and natural gas properties.

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Proved Oil and Gas Reserves

Our engineering estimates of proved oil and gas reserves directly impact financial accounting estimates, including depreciation, depletion and amortization expense and the full cost ceiling limitation. Proved oil and gas reserves are the estimated quantities of oil and gas reserves that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under period-end economic and operating conditions. The process of estimating quantities of proved reserves is very complex, requiring significant subjective decisions in the evaluation of all geological, engineering and economic data for each reservoir. Accordingly, our reserve estimates are developed internally and subsequently, provided to Netherland Sewell & Associates, Inc. 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 consolidated balance sheet and the depreciation, depletion and amortization amounts in the consolidated statement of operations. For more information regarding reserve estimation, including historical reserve revisions, refer to Item 8. Financial Statements and Supplementary Data, Supplemental Oil and Gas Disclosures.

Full Cost Ceiling Limitation

Under the full cost method, we are subject to quarterly calculations of a “ceiling” or limitation on the amount of costs associated with our oil and gas properties that can be capitalized on our balance sheet. This ceiling limits such capitalized costs to the present value of estimated future cash flows from proved oil and natural gas reserves (including the effect of any related hedging activities) reduced by future operating expenses, development expenditures, abandonment costs (net of salvage values) to the extent not included in oil and gas properties pursuant to SFAS No. 143, and estimated future income taxes thereon. If net capitalized costs exceed the applicable cost center ceiling, we are subject to a ceiling test write-down to the extent of such excess. If required, it would reduce earnings and stockholders’ equity in the period of occurrence and result in lower DD&A 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. 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 but prior to the issuance of our financial statements in which a write-down might otherwise be required. The full cost ceiling test impairment calculations also take into consideration the effects of hedging contracts that are designated for hedge accounting. Given the fluctuation of natural gas and oil prices, it is reasonably possible that the estimated discounted future net cash flows from our proved reserves will change in the near term. If natural gas and oil prices decline, or if we have downward revisions to our estimated proved reserves, it is possible that write-downs of our oil and gas properties could occur in the future.

Our ceiling test computation was calculated quarterly using hedge adjusted market prices based on Henry Hub gas prices and West Texas Intermediate oil prices. At September 30, 2008, the ceiling test computation was based on a Henry Hub price of $7.12 per MMBtu and a West Texas Intermediate oil price of $96.37 per Bbl (adjusted for basis and quality differentials). At December 31, 2008, the ceiling test computation was based on a Henry Hub price of $5.71 per MMBtu and a West Texas Intermediate oil price of $41.00 per Bbl (adjusted for basis and quality differentials). The use of these prices resulted in non-cash, pre-tax writedowns of $205.7 million and $238.7 million at September 30, 2008 and December 31, 2008, respectively. Due to the volatility of commodity prices, should natural gas prices continue to decline in the future, it is possible that an additional write-down could occur.

There were no ceiling test write-downs for the years ended December 31, 2007 and 2006.

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 $0.14 to $0.16 per MMcfe. This estimated impact is based on current data at December 31, 2008 and actual events could require different adjustments to DD&A.

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Costs Withheld From Amortization

Costs associated with unevaluated properties are excluded from our amortization base until we have evaluated the properties. The costs associated with unevaluated leasehold acreage wells, currently drilling and capitalized interest are initially excluded from our amortization base. Leasehold costs are either transferred to our amortization base with the costs of drilling a well on the lease or are assessed quarterly for possible impairment or reduction in value. In addition, a portion of incurred (if not previously included in the amortization base) and future estimated development costs associated with qualifying major development projects may be temporarily excluded from amortization. To qualify, a project must require significant costs to ascertain the quantities of proved reserves attributable to the properties under development (e.g., the installation of an offshore production platform from which development wells are to be drilled). Incurred and estimated future development costs are allocated between completed and future work. Any temporarily excluded costs are included in the amortization base upon the earlier of when the associated reserves are determined to be proved or impairment is indicated.

Our decision to withhold costs from amortization and the timing of the transfer of those costs into the amortization base involve a significant amount of judgment and may be subject to changes over time based on several factors, including our drilling plans, availability of capital, project economics and results of drilling on adjacent acreage. At December 31, 2008, our domestic full cost pool had approximately $50.3 million of costs excluded from the amortization base.

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 Statement of Financial Accounting Standards (“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.

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 portion of our expected natural gas production through 2010. As of December 31, 2008, 37% and 4% of our natural gas production was hedged using swaps and costless collars, respectively, with settlement in 2009 and 9% of our natural gas production was hedged with swaps for settlement in 2010, based on our annual reserve report. 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 and 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) in the Consolidated Statement of Operations.

Fair Value Measurements

In September 2006, the Financial Accounting Standards Board ("FASB") issued SFAS No. 157, "Fair Value Measurements" ("SFAS No. 157"). SFAS No. 157 defines fair value, establishes a framework for measuring fair value and expands the related disclosure requirements. SFAS No. 157 does not require any new fair value measurements but may require some entities to change their measurement practices. 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 also issued FASB Staff Position ("FSP") FAS 157-2 ("FSP No. 157-2"), which delayed 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. Effective January 1, 2008, the Company partially adopted SFAS No. 157 and has chosen to defer the implementation of SFAS No.157 for nonfinancial assets and liabilities in accordance with FSP No. 157-2. Accordingly, the Company will apply SFAS No. 157 to its nonfinancial assets and liabilities that are disclosed or recognized at fair value on a nonrecurring basis and other assets and liabilities in the first quarter of 2009. We are still in the process of evaluating the effect of SFAS No. 157 on our nonfinancial assets and liabilities and therefore have not yet determined the impact that it will have on our financial statements upon full adoption in 2009. Nonfinancial assets and liabilities for which we have not yet applied the provisions of SFAS No. 157 include our asset retirement obligations. The adoption of SFAS No. 157 for financial assets and liabilities did not have a significant effect on our consolidated financial position, results of operations or cash flows. See Item 8. Financial Statements and Supplementary Data, Note 7 - Fair Value Measurements.

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.

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 our oil and gas properties. It is more likely than not that we will realize this deferred tax asset in future years and therefore, we have not recorded a valuation allowance as of December 31, 2008. See Item 8. Consolidated Financial Statements and Supplementary Data, Note 13 - Income Taxes.

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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 (benefit) by approximately $3.0 million for the year ended December 31, 2008.

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

The following recently issued accounting developments may impact the Company in future periods.

Business Combinations. In December 2007, the FASB issued SFAS No. 141(R), "Business Combinations" ("SFAS No. 141R"). SFAS No. 141R broadens the guidance of SFAS No. 141, extending its applicability to all transactions and other events in which one entity obtains control over one or more other businesses. It broadens the fair value measurement and recognition of assets acquired, liabilities assumed, and interests transferred as a result of business combinations and requires that acquisition-related costs incurred prior to the acquisition be expensed. SFAS No. 141R also expands the definition of what qualifies as a business, and this expanded definition could include prospective oil and gas purchases. This could cause us to expense transaction costs for future oil and gas property purchases that we have historically capitalized. Additionally, SFAS No. 141R expands the required disclosures to improve the statement users' abilities to evaluate the nature and financial effects of business combinations. SFAS No. 141R is effective for business combinations for which the acquisition date is on or after January 1, 2009.

Noncontrolling Interests in Consolidated Financial Statements. In December 2007, the 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 the Company's consolidated financial position, results of operations or cash flows.

Disclosures about Derivative Instruments and Hedging Activities. In March 2008, the FASB issued SFAS No. 161, "Disclosures about Derivative Instruments and Hedging Activities – an Amendment of FASB Statement No. 133" ("SFAS No. 161"), which is intended to improve financial reporting about derivative instruments and hedging activities by requiring enhanced disclosures. This statement is effective for fiscal years beginning after November 15, 2008. We do not expect the adoption of SFAS No. 161 to have a material impact on the Company's consolidated financial position, results of operations or cash flows.

Fair Value Measurements. In October 2008, the FASB issued FSP FAS 157-3, "Determining the Fair Value of a Financial Asset When the Market for That Asset Is Not Active" ("FSP FAS 157-3"). This FSP clarifies the application of SFAS No. 157 in a market that is not active and provides an example to illustrate key considerations in determining the fair value of a financial asset when the market for that financial asset is not active. This FSP was effective upon issuance, including prior periods for which financial statements have not been issued. We applied this FSP to financial assets measured at fair value on a recurring basis at September 30, 2008. See Item 8. Financial Statements and Supplementary Data, Note 7 - Fair Value Measurements. The adoption of FSP FAS 157-3 did not have a significant impact on our consolidated financial position, results of operations or cash flows.

Oil and Gas Reporting Requirements. In December 2008, the SEC released Release No. 33-8995, “Modernization of Oil and Gas Reporting” (the “Release”). The disclosure requirements under this Release will permit reporting of oil and gas reserves using an average price based upon the prior 12-month period rather than year-end prices and the use of new technologies to determine proved reserves if those technologies have been demonstrated to result in reliable conclusions about reserves volumes. Companies will also be allowed to disclose probable and possible reserves in SEC filings. In addition, companies will be required to report the independence and qualifications of its reserves preparer or auditor and file reports when a third party is relied upon to prepare reserves estimates or conduct a reserves audit. The new disclosure requirements become effective for the Company beginning with our annual report on Form 10-K for the year ended December 31, 2009. We are currently evaluating the impact of this Release on our oil and gas accounting disclosures.

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Results of Operations

The following table summarizes our results of operations and compares the year ended December 31, 2008 to the years ended December 31, 2007 and 2006.

	Year Ended December 31,		
	2008	2007	2006
	(In thousands, except per unit amounts)		
Revenues:			
Natural gas sales	$ 443,611	$ 323,341	$ 236,496
Oil sales	$ 55,736	$ 40,148	$ 35,267
Total revenues	$ 499,347	$ 363,489	$ 271,763
Production:			
Gas (Bcf)	50.4	42.5	30.3
Oil (MBbls)	546.4	561.2	551.3
Total Equivalents (Bcfe)	53.6	45.8	33.4
$ per unit:			
Avg. Gas Price per Mcf	$ 8.80	$ 7.61	$ 7.81
Avg. Gas Price per Mcf excluding Hedging	9.17	7.07	6.83
Avg. Oil Price per Bbl	102.00	71.54	64.01
Avg. Revenue per Mcfe	$ 9.32	$ 7.94	$ 8.14

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.

Year Ended December 31, 2008 Compared to the Year Ended December 31, 2007

Total revenue for the year ended December 31, 2008 was $499.3 million which is an increase of $135.9 million, or 37%, from the year ended December 31, 2007. Approximately 89% of revenue was attributable to natural gas sales on total volumes of 53.6 Bcfe.

Natural Gas. For the year ended December 31, 2008, natural gas revenue increased by 37% or $120.3 million, including the realized impact of derivative instruments, from the comparable period in 2007, to $443.6 million. The increase is primarily attributable to increased volumes and favorable average realized prices in 2008. Production volumes increased overall by 19%, or 7.9 Bcfe, primarily due to the increase in the number of productive wells during 2008. Net productive wells increased from 606 in 2007 to 825 in 2008. The effect of gas hedging activities on natural gas revenue for the year ended December 31, 2008 was a loss of $18.7 million or a decrease of $0.37 per Mcf as compared to a gain of $22.9 million or an increase of $0.54 per Mcf for the year ended December 31, 2007. The average realized natural gas price including the effects of hedging increased 16% or $1.19 to $8.80 per Mcf for the year ended December 31, 2008 as compared to the same period in 2007 of $7.61 per Mcf. In 2008, the Henry Hub natural gas spot price averaged $9.13 per Mcf compared to the 2007 average of $7.17 per Mcf.

Crude Oil. For the year ended December 31, 2008, oil revenue increased by 39% or $15.6 million primarily due to the increase of $30.46 per Bbl in the average oil price from $71.54 per Bbl for the year ended December 31, 2007 as compared to $102.00 per Bbl for the year ended December 31, 2008. At December 31, 2008, the West Texas Intermediate price for oil was $41.00 per Bbl compared to $92.50 per Bbl at December 31, 2007. Oil volumes decreased by 3% or 14.8 MBbls to 546.4 MBbls at December 31, 2008 from 561.2 MBbls at December 31, 2007. The decrease in oil production volumes was associated with decreased production in the Gulf of Mexico primarily due to the effects of Hurricane Ike in September 2008 as well as lower production in Other Onshore.

Year Ended December 31, 2007 Compared to the Year Ended December 31, 2006

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 37% or $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. In addition, production volumes increased overall by 40% or 12.2 Bcfe. 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 or an increase of $0.54 per Mcf 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 3% 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.

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Crude Oil. For the year ended December 31, 2007, oil revenue increased by 14% or $4.9 million primarily due to the increase of $7.53 per Bbl in the average oil price from $64.01 per Bbl for the year ended December 31, 2006 as compared to $71.54 per Bbl for the year ended December 31, 2007. Oil volumes increased by 2% or 9.9 MBbls to 561.2 MBbls at 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

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 per Mcf 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.

Operating Expenses

The following table presents information about our operating expenses:

	Year Ended December 31,		
	2008	2007	2006
	(In thousands, except per unit amounts)		
Lease operating expense	$ 55,694	$ 47,044	$ 36,273
Depreciation, depletion and amortization	198,862	152,882	105,886
Impairment of oil and gas properties	444,369	-	-
Production taxes	13,528	6,417	6,433
General and administrative costs	$ 52,846	$ 43,867	$ 33,233
$ per unit:			
Avg. lease operating expense per Mcfe	$ 1.04	$ 1.03	$ 1.09
Avg. DD&A per Mcfe	3.71	3.34	3.17
Avg. production taxes per Mcfe	0.25	0.14	0.19
Avg. G&A per Mcfe	$ 0.99	$ 0.96	$ 1.00

Year Ended December 31, 2008 Compared to the Year Ended December 31, 2007

Lease Operating Expense. Lease operating expense increased $8.7 million for the year ended December 31, 2008 as compared to the same period for 2007. This overall increase is primarily due to the increase in the number of productive wells as well as increased production of 17% for 2008 which led to higher costs for equipment rentals, maintenance and repairs, and costs associated with non-operated properties. Lease operating expense includes workover costs of $0.14 per Mcfe, ad valorem taxes of $0.21 per Mcfe and insurance of $0.03 per Mcfe for the year ended December 31, 2008 as compared to workover costs of $0.11 per Mcfe, ad valorem taxes of $0.26 per Mcfe and insurance of $0.05 per Mcfe for the same period in 2007.

Depreciation, Depletion, and Amortization. Depreciation, depletion and amortization expense increased $46.0 million for the year ended December 31, 2008 as compared to the same period for 2007. The increase is due to a 17% increase in total production and a higher DD&A rate for 2008 due to the decrease in oil and natural gas reserves as compared to 2007. The DD&A rate for the respective period in 2008 was $3.71 per Mcfe while the rate for the same period in 2007 was $3.34 per Mcfe due to the increase in finding costs. Our DD&A rate for the first quarter of 2009 is expected to be $3.03 per Mcfe after the effects of the full cost ceiling write-down.

Impairment of Oil and Gas Properties. Based upon the quarterly ceiling test computations using hedge adjusted market prices in effect at September 30, 2008 and December 31, 2008, and in conjunction with the downward revisions of a portion of the Company's reserves in the third and fourth quarters of 2008, the net capitalized costs of oil and natural gas properties exceeded the cost center ceiling at September 30 and December 31, 2008 and a pre-tax, non-cash impairment expense of $444.4 million was recorded.

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Production Taxes. Production taxes as a percentage of oil and natural gas sales were 2.7% for the year ended December 31, 2008 as compared to 1.8% for the year ended December 31, 2007. This increase is the result of increased production in areas that do not qualify for tax credits for the year ended December 31, 2008 as compared to the same period for 2007.

General and Administrative Costs. General and administrative costs, net of capitalized general and administrative costs of $7.1 million for the year ended December 31, 2008, increased by $9.0 million for the year ended December 31, 2008 as compared to the same period for 2007, with capitalized general and administrative costs of $5.5 million. The increase in costs incurred in the current period are primarily related to increases in legal fees related to the Calpine litigation of $6.9 million and increases in payroll expenses of $2.1 million resulting from increased headcount and a $1.3 million accrual related to the severance of a former executive officer, as well as the absence of approximately $5.0 million in CEO transition costs that were incurred in 2007 but not 2008.

Year Ended December 31, 2007 Compared to the Year Ended December 31, 2006

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 per Mcfe 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 2007 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.

Year Ended December 31, 2006

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.

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Total Other Expense

Other expense includes interest expense, interest income and other income/expense, net which increased $10.2 million for the year ended December 31, 2008 as compared to the respective period in 2007. The increase in other expense is the result of a $12.4 million charge related to the Calpine Settlement partially offset by $3.0 million decrease in interest expense in 2008.

Other expense increased $2.5 million for the year ended December 31, 2007 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. We expended $35.3 million during the fourth quarter of 2006 to fund various asset acquisitions and $38.7 million during the second quarter of 2007 for the acquisition of the OPEX Properties.

Other expense for the year ended December 31, 2006 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.

Provision for Income Taxes

Our 2008 income tax benefit of $112.8 million was primarily due to the 2008 ceiling test write-downs. For the year ended December 31, 2008, the effective tax rate was 37.5% compared to the effective tax rate of 37.3% for the year ended December 31, 2007 and 38.3% for the year ended December 31, 2006. 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 a portion 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. The effects of these derivative transactions on our natural gas sales are discussed above under “Results of Operations – Natural Gas.” The majority of our capital expenditures are discretionary and could be curtailed if our cash flows decline from expected levels. Current economic conditions and lower commodity prices could adversely affect our cash flow and liquidity. We will continue to monitor our cash flow and liquidity and if appropriate, we may consider adjusting our capital expenditure program.

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 and expires on April 5, 2010. Availability under the Revolver is restricted to the borrowing base. 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 June 2008, the borrowing base was adjusted to $400.0 million and affirmed in December 2008. The next borrowing base review is scheduled to begin on March 2, 2009. 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%. These rates over LIBOR were adjusted in June 2008 to be 1.125% to 1.875%. 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 membership interests 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. At December 31, 2008, the Company's current ratio was 2.7 and the leverage ratio was 0.8. 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, 2008. As of December 31, 2008, the Company had $175.0 million available for borrowing under their revolving line of credit. All amounts drawn under the Revolver are due and payable on April 5, 2010.

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Second Lien Term Loan. BNP Paribas, in July 2005, also provided the Company with a second lien term loan concurrent with the Acquisition of oil and gas properties from Calpine ("Term Loan"). Borrowings under the Term Loan are $75.0 million as of December 31, 2008. Such borrowings are syndicated to a group of lenders including BNP Paribas. Borrowings under the Term Loan bear interest at LIBOR plus 4.00%. 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. At December 31, 2008, the Company's asset coverage ratio was 3.1 and the leverage ratio was 0.8. 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, 2008. The 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 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 Revolver maturing on April 5, 2010. We are in discussion with the lenders under our Revolver to extend the maturity of the Revolver and the Term Loan. If we are unable to extend the maturity of the Revolver, it will become a current liability on April 5, 2009 and would result in Rosetta being in default with respect to the working capital covenants in the revolving credit facility and second lien term loan. Similarly, if we are unable to extend the maturity of the Term Loan, it will become a current liability on July 7, 2009. We believe that we will be successful in extending these maturities on acceptable terms and conditions. Current market conditions are expected to result in increased costs of borrowing.

Working Capital

At December 31, 2008, we had a working capital surplus of $28.6 million as compared to a working capital deficit of $62.9 million at December 31, 2007. 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 surplus was largely caused by the increases in our cash balance and short-term hedged assets in conjunction with a decrease in our accounts payable and other current liabilities balances. As of December 31, 2008, the working capital asset balances of our cash and cash equivalents and derivative instruments were approximately $42.9 million and $34.7 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 $48.8 million as of December 31, 2008.

Cash Flows

	Year Ended December 31,		
	2008	2007	2006
		(In thousands)	
Cash flows provided by operating activities	$ 374,719	$ 257,307	$ 199,610
Cash flows used in investing activities	(393,070)	(322,041)	(236,064)
Cash flows provided by (used in) financing activities	57,990	5,170	(490)
Net increase (decrease) in cash and cash equivalents	$ 39,639	$ (59,564)	$ (36,944)

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, 2008.

Cash flows provided by operating activities increased by $117.4 million for the year ended December 31, 2008 as compared to the same period for 2007. This increase is largely due to higher natural gas and oil prices during 2008 compared to 2007. As noted above, we also had a working capital surplus of $28.6 million, which was largely caused by the increase in our cash balance. For the year ended December 31, 2008, we incurred approximately $334.4 million in capital expenditures as compared to $336.1 million for the year ended December 31, 2007. For the year ended December 31, 2008, we had net losses of $188.1 million with an increase of production of 17% as compared to the year ended December 31, 2007 with net income of $57.2 million.

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, oil and gas properties impairments, 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.

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.

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

Cash flows used in investing activities increased by $71.0 million for the year ended December 31, 2008 as compared to the same period for 2007 and related to our expenditures for the acquisitions and development of oil and gas properties and drilling. The Company acquired the Petroflow properties in the San Juan Basin for $29.0 million, the Pinedale and South Texas properties for approximately $55.0 million, and the Calpine non-consent properties as part of the Calpine Settlement for $30.9 million. Additionally, acquisition costs for the year ended December 31, 2008 include a non-cash purchase price adjustment of $36.7 million related to the release of suspended revenues and non-consent liabilities associated with non-consent properties as part of the Calpine Settlement, as well as an $8.0 million reduction in accrued capital costs. During the year ended December 31, 2008, we participated in the drilling of 184 gross wells as compared to the drilling of 195 gross wells for the year ended December 31, 2007.

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.

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 $52.8 million for the year ended December 31, 2008 as compared to the same period for 2007. The net increase is primarily related to net borrowings of $55 million made in 2008 against the Revolver. In addition, there was an increase of approximately $3.0 million in the stock options exercised for the year ended December 31, 2008 compared to 2007.

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.

Commodity Price Risk, Interest Rate Risk 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 hedges 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 these activities 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 portion of our expected natural gas production through 2010. 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.

The following table sets forth the results of commodity hedging transaction settlements for the year ended December 31, 2008:

	For the Year Ended December 31,	
	2008	2007
Natural Gas		
Quantity settled (MMBtu)	26,684,616	23,464,500
Increase (decrease) in natural gas sales revenue (In thousands)	$ (18,669)	$ 22,926
Interest Rate Swaps		
Decrease (increase) in interest expense (In thousands)	$ (1,158)	$ 20

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Borrowings under our Revolver and Term Loan mature on April 5, 2010 and July 7, 2010, respectively, and bear interest at a LIBOR-based rate. This exposes us to risk of earnings loss due to increases in market interest rates. To mitigate this exposure, we have entered into a series of interest rate swap agreements through June 2009. 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.

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, 2008, 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, 2008 were $334.4 million, and we have plans to carefully execute an organic capital program in 2009 that can be funded from internally generated cash flows. We also have the discretion to use available cash, borrowing base, and proceeds from divestitures to fund capital expenditures, including acquisitions, that make sense for Rosetta. However, our main priority is to preserve liquidity.

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, 2008, the aggregate amounts of our contractually obligated payment commitments for the next five years are as follows:

	Payments Due By Period				
	Total	2009	2010 to 2011	2012 to 2013	2014 & Beyond
			(In thousands)		
Senior secured revolving line of credit	$ 225,000	$ -	$ 225,000	$ -	$ -
Second lien term loan	75,000	-	75,000	-	-
Operating leases	15,793	3,055	6,021	6,204	513

Interest payments on long-term debt (1)		10,494		7,638		2,856		-		-
Rig commitments		5,025		5,025		-		-		-
Total contractual obligations	$	331,312	$	15,718	$	308,877	$	6,204	$	513

(1) Future interest payments were calculated based on interest rates and amounts outstanding at December 31, 2008.

Asset Retirement Obligation. The Company also has liabilities of $27.9 million related to asset retirement obligations on its Consolidated Balance Sheet at December 31, 2008 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. Financial Statements and Supplementary Data, Note 9 - Asset Retirement Obligation.

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.

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Off-Balance Sheet Arrangements

At December 31, 2008 and 2007, we did not have any off-balance sheet arrangements.

Forward-Looking Statements

This report includes forward-looking information regarding Rosetta that is intended to be covered by the "forward-looking statements" within the meaning of the Private Securities Litigation Reform Act of 1995, 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," "intend," "anticipate," "believe," "estimate," "predict," "potential," "pursue," "target" or negative of such terms or variations 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 Part I. of 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:

- conditions in the energy and economic markets;
- the supply and demand for natural gas and oil;
- the price of natural gas and oil;
- potential reserve revisions;
- changes or advances in technology;
- reserve levels;
- inflation;
- the availability and cost of relevant raw materials, goods and services;
- future processing volumes and pipeline throughput;

- 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;

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– our ability to obtain credit and/or capital in desired amounts and/or on favorable terms;

– failure of our joint interest partners to fund any or all of their portion of any capital program;

– 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;

– 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.

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. See Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations “ Commodity Price Risk, Interest Rate Risk and Related Hedging Activities.”

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.

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.

We use derivative transactions to manage exposure to changes in commodity prices and interest rates. Our objective for holding derivative instruments is 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.

On December 31, 2008, we had open natural gas derivative hedges in an asset position with a fair value of $39.4 million. A 10 percent increase in natural gas prices would reduce the fair value by approximately $15.1 million, while a 10 percent decrease in natural gas prices would increase the fair value by approximately $14.7 million. These fair value changes assume volatility based on prevailing market parameters at December 31, 2008.

As of December 31, 2008, we had the following financial fixed price swap positions outstanding with average underlying prices that represent hedged prices of commodities at various market locations:

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Settlement Period	Derivative Instrument	Hedge Strategy	Notional Daily Volume MMBtu	Total of Notional Volume MMBtu	Average Floor/Fixed Prices MMBtu	Average Ceiling Prices MMBtu	Natural Gas Production Hedged (1)	Fair Market Value Gain/(Loss) (In thousands)
2009	Swap	Cash flow	52,141	19,031,465	$ 7.65	$ -	37%	$ 31,082
2009	Costless Collar	Cash flow	5,000	1,825,000	8.00	10.05	4%	3,660
2010	Swap	Cash flow	10,000	3,650,000	8.31	-	9%	4,615
				24,506,465				$ 39,357

(1) Estimated based on anticipated future gas production.

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 $400 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 1.125% to 1.875%, based on facility utilization. The Revolver will mature on April 5, 2010.

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.

We had availability under the Revolver of $175.0 million as of December 31, 2008. A one hundred basis point increase in each of the LIBOR rate and federal funds rate as of December 31, 2008 and 2007 for both our Revolver and Term Loan would result in an estimated $3.0 million and $2.5 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 $50.0 million of our variable rate debt through June 2009. As of December 31, 2008 we had the following financial interest rate swap positions outstanding:

Settlement	Derivative	Hedge

Period	Instrument	Strategy	Average Fixed Rate	Fair Market Value Gain/(Loss) (In thousands)
2009	Swap	Cash flow	4.55%	$ (985)
				$ (985)

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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 present fairly, in all material respects, the financial position of Rosetta Resources Inc. and its subsidiaries (the "Company") at December 31, 2008 and 2007, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2008 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, 2008, 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 Annual 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 were integrated audits in 2008 and 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.

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 27, 2009
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, 2008	December 31, 2007
Assets		
Current assets:		
Cash and cash equivalents	$ 42,855	$ 3,216
Restricted cash	1,421	-
Accounts receivable	41,885	55,048
Derivative instruments	34,742	3,966
Prepaid expenses	5,046	10,413
Other current assets	4,071	4,249
Total current assets	130,020	76,892
Oil and natural gas properties, full cost method, of which $50.3 million at December 31, 2008 and $40.9 million at December 31, 2007 were excluded from amortization	1,900,672	1,566,082
Other property and equipment	9,439	6,393
	1,910,111	1,572,475
Accumulated depreciation, depletion, and amortization, including impairment	(935,851)	(295,749)
Total property and equipment, net	974,260	1,276,726
Deferred loan fees	1,168	2,195
Deferred tax asset	42,652	-
Other assets	6,278	1,401
Total other assets	50,098	3,596
Total assets	$ 1,154,378	$ 1,357,214
Liabilities and Stockholders' Equity		
Current liabilities:		
Accounts payable	$ 2,268	$ 33,949
Accrued liabilities	48,824	64,216
Royalties payable	17,388	18,486
Derivative instruments	985	2,032
Prepayment on gas sales	19,382	20,392
Deferred income taxes	12,575	720
Total current liabilities	101,422	139,795
Long-term liabilities:		
Derivative instruments	-	13,508
Long-term debt	300,000	245,000
Asset retirement obligation	26,584	18,040
Deferred income taxes	-	67,916
Total liabilities	428,006	484,259
Commitments and Contingencies (Note 11)		
Stockholders' equity:		
	-	-

Preferred stock, $0.001 par value; authorized 5,000,000 shares; no shares issued in 2008 or 2007		
Common stock, $0.001 par value; authorized 150,000,000 shares; issued 51,031,481 shares and 50,542,648 shares at December 31, 2008 and December 31, 2007, respectively	51	50
Additional paid-in capital	773,676	762,827
Treasury stock, at cost; 155,790 shares and 109,303 shares at December 31, 2008 and 2007, respectively	(2,672)	(2,045)
Accumulated other comprehensive income (loss)	24,079	(7,225)
Retained earnings (accumulated deficit)	(68,762)	119,348
Total stockholders' equity	726,372	872,955
Total liabilities and stockholders' equity	$ 1,154,378	$ 1,357,214

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

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

	Year Ended December 31, 2008	2007	2006
Revenues:			
Natural gas sales	$ 443,611	$ 323,341	$ 236,496
Oil sales	55,736	40,148	35,267
Total revenues	499,347	363,489	271,763
Operating costs and expenses:			
Lease operating expense	55,694	47,044	36,273
Depreciation, depletion, and amortization	198,862	152,882	105,886
Impairment of oil and gas properties	444,369	-	-
Treating and transportation	6,323	4,230	2,544
Marketing fees	3,064	2,450	2,257
Production taxes	13,528	6,417	6,433
General and administrative costs	52,846	43,867	33,233
Total operating costs and expenses	774,686	256,890	186,626
Operating income (loss)	(275,339)	106,599	85,137
Other (income) expense			
Interest expense, net of interest capitalized	14,688	17,734	17,428
Interest income	(1,600)	(1,674)	(4,503)
Other (income) expense, net	12,510	(698)	(40)
Total other expense	25,598	15,362	12,885
Income (loss) before provision for income taxes	(300,937)	91,237	72,252
Income tax expense (benefit)	(112,827)	34,032	27,644
Net income (loss)	$ (188,110)	$ 57,205	$ 44,608
Earnings (loss) per share:			
Basic	$ (3.71)	$ 1.14	$ 0.89
Diluted	$ (3.71)	$ 1.13	$ 0.88
Weighted average shares outstanding:			
Basic	50,693	50,379	50,237
Diluted	50,693	50,589	50,408

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

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

	Year Ended December 31, 2008	2007	2006
Cash flows from operating activities			
Net income (loss)	(188,110)	57,205	44,608
Adjustments to reconcile net income to net cash from operating activities			
Depreciation, depletion and amortization	198,862	152,882	105,886
Impairment of oil and gas properties	444,369	-	-
Deferred income taxes	(116,519)	33,915	27,472
Amortization of deferred loan fees recorded as interest expense	1,027	1,180	1,180
Stock compensation expense	7,234	6,831	5,702
Other non-cash items	(512)	(181)	(171)
Change in operating assets and liabilities:			
Accounts receivable	13,163	(18,640)	3,643
Income taxes receivable	(776)	-	6,000
Prepaid expenses	5,367	(1,652)	650
Other current assets	178	(1,284)	(2,965)
Other assets	191	144	1,691
Accounts payable	5,031	10,909	8,765
Accrued liabilities	7,322	3,998	310
Royalties payable	(2,108)	12,000	(3,161)
Net cash provided by operating activities	374,719	257,307	199,610
Cash flows from investing activities			
Acquisition of oil and gas properties	(163,187)	(38,656)	(35,286)
Purchases of oil and gas assets	(228,464)	(284,541)	(201,293)
Increase in restricted cash	(1,421)	-	-
Other	2	1,156	515
Net cash used in investing activities	(393,070)	(322,041)	(236,064)
Cash flows from financing activities			
Equity offering transaction fees	-	-	268
Borrowings on revolving credit facility	55,000	10,000	-
Payments on revolving credit facility	-	(5,000)	-
Proceeds from stock options exercised	3,617	653	804
Purchases of treasury stock	(627)	(483)	(1,562)
Net cash provided by (used in) financing activities	57,990	5,170	(490)
Net increase (decrease) in cash	39,639	(59,564)	(36,944)
Cash and cash equivalents, beginning of year	3,216	62,780	99,724
Cash and cash equivalents, end of year	$ 42,855	$ 3,216	$ 62,780
Supplemental disclosures:			
Cash paid for interest expense, net of capitalized interest	$ 13,658	$ 18,862	$ 17,875
Cash paid for income taxes	$ 4,470	$ 115	$ 172
Supplemental non-cash disclosures:			
Capital expenditures included in Accrued liabilities	$ 26,555	$ 34,599	$ 21,674

Accrued purchase price adjustment	$ -	$ -	$ 11,400
Release of suspended net revenues resulting from Calpine Settlement included in Accounts payable and Acquisition of oil and gas properties	$ 36,713	$ -	$ -

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

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Rosetta Resources Inc.
Consolidated Statement of Stockholders' Equity
(In thousands, except share amounts)

	Common Stock Shares	Common Stock Amount	Additional Paid-In Capital	Treasury Stock Shares	Treasury Stock Amount	Accumulated Other Comprehensive (Loss)/Income	Retained Earnings / (Accumulated Deficit)	Total Stockholders' Equity
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 expense 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
Stock options exercised	214,119		1		3,615	-		-		-		-	3,616
Treasury stock - employee tax payment	-		-		-	46,487		(627)		-		-	(627)
Stock-based compensation	-		-		7,234	-		-		-		-	7,234
Vesting of restricted stock	274,714		-		-	-		-		-		-	-
Comprehensive Loss:	-		-		-	-		-		-		-	-
Net Loss	-		-		-	-		-		-		(188,110)	(188,110)
Change in fair value of derivative hedging instruments	-		-		-	-		-		30,059		-	30,057
Hedge settlements reclassified to income	-		-		-	-		-		19,827		-	19,829
Tax expense related to cash flow hedges	-		-		-	-		-		(18,582)		-	(18,582)
Comprehensive Loss	-		-		-	-		-		-		-	(156,806)
Balance December 31, 2008	51,031,481	$	51	$	773,676	155,790	$	(2,672)	$	24,079	$	(68,762)	$ 726,372

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

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Rosetta Resources Inc.

Notes to Consolidated Financial Statements

(1) Organization and Operations of the Company

Nature of Operations. Rosetta Resources Inc. (together with its consolidated subsidiaries, the "Company") is an independent oil and gas company that 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 Rockies, 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 current year classifications. These reclassifications have no impact on net income (loss).

(2) Summary of Significant Accounting Policies

Principles of Consolidation and Basis of Presentation

The accompanying consolidated financial statements for the years ended December 31, 2008, 2007 and 2006 contain the accounts of Rosetta Resources Inc. and its majority owned subsidiaries after eliminating all significant intercompany balances and transactions.

Use of Estimates in Preparation of Financial Statements

The preparation of the consolidated 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,valuation of derivative instruments, 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.

With respect to the current market environment for liquidity and access to credit, the Company, through banks participating in its credit facility, has invested available cash in money market accounts and funds whose investments are limited to United States Government Securities, securities backed by the United States Government, or securities of United States Government agencies. The Company followed this policy prior to the recent changes in credit markets, and believes this is an appropriate approach for the investment of Company funds in the current environment.

Restricted Cash

Restricted cash of $1.4 million as of December 31, 2008 consists of cash deposited by the Company in an escrow account, which was created in conjunction with the South Texas acquisitions for potential environmental remediation costs associated with acquired properties.

Allowance for Doubtful Accounts

The Company regularly reviews all aged accounts receivables for collectability and establishes an allowance as necessary for individual customer balances.

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Property, Plant and Equipment, Net

The Company follows the full cost method of accounting for oil and natural gas properties. 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 reserves in the cost center in which they are 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 $7.1 million and $5.5 million of internal costs for the years ended December 31, 2008 and 2007, 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. This ceiling limits such capitalized costs to the present value of estimated future cash flows from proved oil and natural gas reserves (including the effect of any related hedging activities) reduced by future operating expenses, development expenditures, abandonment costs (net of salvage values) to the extent not included in oil and gas properties pursuant to SFAS No. 143, and estimated future income taxes thereon. However, in periods in which a write-down is required, if oil and gas prices increase subsequent to the end of a quarter but prior to the issuance of our financial statements, the Company may not be subject to a write-down. 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 quarterly using hedge adjusted market prices based on Henry Hub gas prices and West Texas Intermediate oil prices. At September 30, 2008, the ceiling test computation was based on a Henry Hub price of $7.12 per MMBtu and a West Texas Intermediate oil price of $96.37 per Bbl (adjusted for basis and quality differentials). At December 31, 2008, the ceiling test computation was based on a Henry Hub price of $5.71 per MMBtu and a West Texas Intermediate oil price of $41.00 per Bbl (adjusted for basis and quality differentials). Cash flow hedges of natural gas production in place at September 30 and December 31, 2008 increased the calculated ceiling value by approximately $37 million (pre-tax) and $47 million (pre-tax), respectively. Based upon studies to date, and in coordination with the Company's independent reserve engineers, the Company recognized a downward revision of 64 Bcfe of proved reserves during the third quarter of 2008. Based upon this analysis and the reserve revision, a non-cash, pre-tax write-down of $205.7 million was recorded at September 30, 2008. Due to continued declines in oil and gas prices and a downward revision of 8 Bcfe due to year-end commodity prices, at December 31, 2008, capitalized costs of our proved oil and gas properties exceeded our ceiling, resulting in a non-cash, pre-tax write-down of $238.7 million. Due to the volatility of commodity prices, should natural gas prices continue to decline in the future, it is possible that an additional write-down could occur.

No impairment charge was recorded for the years ended December 31, 2007 and 2006.

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, 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. The carrying amount reported in the consolidated balance sheet at December 31, 2008 for long-term debt is $300 million. The Company adjusted the fair value measurement of its long-term debt as of December 31, 2008, in accordance with SFAS No. 157 using a discounted cash flow technique that incorporates a market interest yield curve with adjustments for duration, optionality and risk profile. The Company has determined the fair market value of its debt to be $275 million at December 31, 2008.

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 and financial institutions, respectively.

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 accumulated 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 6 – Commodity Hedging Contracts and Other Derivatives 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 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.

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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, 2008 or 2007.

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.

Any excess tax benefit is recognized as a credit to additional paid in capital when realized and is calculated as the amount by which the tax deduction we receive exceeds the deferred tax asset associated with the recorded stock compensation expense. We have approximately $0.2 million of related excess tax benefits which will be recognized upon utilization of our net operating loss carryforward. SFAS No. 123R requires the cash flows that result from tax deductions in excess of the compensation expense to be recognized as financing activities.

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, 2008 and 2007, 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, 2008 and 2007, 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 bases 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.

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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

The following recently issued accounting developments may impact the Company in future periods.

Business Combinations. In December 2007, the FASB issued SFAS No. 141(R), "Business Combinations" ("SFAS No. 141R"). SFAS No. 141R broadens the guidance of SFAS No. 141, extending its applicability to all transactions and other events in which one entity obtains control over one or more other businesses. It broadens the fair value measurement and recognition of assets acquired, liabilities assumed, and interests transferred as a result of business combinations and requires that acquisition-related costs incurred prior to the acquisition be expensed. SFAS No. 141R also expands the definition of what qualifies as a business, and this expanded definition could include prospective oil and gas purchases. This could cause us to expense transaction costs for future oil and gas property purchases that we have historically capitalized. Additionally, SFAS No. 141R expands the required disclosures to improve the statement users' abilities to evaluate the nature and financial effects of business combinations. SFAS No. 141R is effective for business combinations for which the acquisition date is on or after January 1, 2009.

Noncontrolling Interests in Consolidated Financial Statements. In December 2007, the 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 the Company's consolidated financial position, results of operations or cash flows.

Disclosures about Derivative Instruments and Hedging Activities. In March 2008, the FASB issued SFAS No. 161, "Disclosures about Derivative Instruments and Hedging Activities – an Amendment of FASB Statement No. 133" ("SFAS No. 161"), which is intended to improve financial reporting about derivative instruments and hedging activities by requiring enhanced disclosures. This statement is effective for fiscal years beginning after November 15, 2008. We do not expect the adoption of SFAS No. 161 to have a material impact on the Company's consolidated financial position, results of operations or cash flows.

Fair Value Measurements. In October 2008, the FASB issued FSP FAS 157-3, "Determining the Fair Value of a Financial Asset When the Market for That Asset Is Not Active" ("FSP FAS 157-3"). This FSP clarifies the application of SFAS No. 157 in a market that is not active and provides an example to illustrate key considerations in determining the fair value of a financial asset when the market for that financial asset is not active. This FSP was effective upon issuance, including prior periods for which financial statements have not been issued. We applied this FSP to financial assets measured at fair value on a recurring basis at September 30, 2008. See Note 7 - Fair Value Measurements. The adoption of FSP FAS 157-3 did not have a significant impact on our consolidated financial position, results of operations or cash flows.

Oil and Gas Reporting Requirements. In December 2008, the SEC released Release No. 33-8995, "Modernization of Oil and Gas Reporting" (the "Release"). The disclosure requirements under this Release will permit reporting of oil and gas reserves using an average price based upon the prior 12-month period rather than year-end prices and the use of new technologies to determine proved reserves if those technologies have been demonstrated to result in reliable conclusions about reserves volumes. Companies will also be allowed to disclose probable and possible reserves in SEC filings. In addition, companies will be required to report the independence and qualifications of its reserves preparer or auditor and file reports when a third party is relied upon to prepare reserves estimates or conduct a reserves audit. The new disclosure requirements become effective for the Company beginning with our annual report on Form 10-K for the year ended December 31, 2009. We are currently evaluating the impact of this Release on our oil and gas accounting disclosures.

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(3) Accounts Receivable

Accounts receivable consisted of the following:

	December 31, 2008	December 31, 2007
	(In thousands)	
Natural gas, NGLs and oil revenue sales	$ 37,982	$ 46,376
Joint interest billings	3,422	7,750
Short-term receivable for royalty recoupment	481	922
Total	41,885	55,048

There are no balances in accounts receivable that will not be collected and that an allowance was unnecessary at December 31, 2008 and December 31, 2007.

(4) Property, Plant and Equipment

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

	December 31, 2008	December 31, 2007
	(In thousands)	
Proved properties	$ 1,813,527	$ 1,499,046
Unproved/unevaluated properties	50,252	40,903
Gas gathering system and compressor stations	36,893	26,133
Other	9,439	6,393
Total	1,910,111	1,572,475
Less: Accumulated depreciation, depletion, and amortization	(935,851)	(295,749)
	$ 974,260	$ 1,276,726

Included in the Company’s oil and natural gas properties are asset retirement costs of $23.2 million and $20.1 million at December 31, 2008 and 2007, respectively, including additions of $1.7 million and $2.1 million for the year ended December 31, 2008 and 2007, respectively.

Pursuant to full cost accounting rules, the Company must perform a ceiling test each quarter on its proved oil and gas assets within each separate cost center. The Company’s ceiling test was calculated using hedge adjusted market prices of gas and oil at September 30 and December 31, 2008, which were based on a Henry Hub price of $7.12 per MMBtu and $5.71 per MMBtu, respectively, and a West Texas Intermediate oil price of $96.37 per Bbl and $41.00 per Bbl (adjusted for basis and quality differentials), respectively. Cash flow hedges of natural gas production in place at September 30 and December 31, 2008 increased the calculated ceiling value by approximately $37 million (pre-tax) and $47 million (pre-tax), respectively. Based upon studies to date, and in coordination with the Company's independent reserve engineers, the Company recognized a downward revision of 64 Bcfe of proved reserves during the third quarter of 2008. Based upon this analysis and the reserve revision, a non-cash, pre-tax write-down of $205.7 million was recorded at September 30, 2008. Due to continued declines in oil and gas prices and a downward revision of 8 Bcfe due to year-end commodity prices, at December 31, 2008, capitalized costs of our proved oil and gas properties exceeded our ceiling, resulting in a non-cash, pre-tax write-down of $238.7 million. It is possible that another write-down of the Company's oil and gas properties could occur in the future should oil and natural gas prices continue to decline and/or the Company experiences downward adjustments to the estimated proved reserves.

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Capitalized costs excluded from depreciation, depletion, and amortization as of December 31, 2008 and 2007, are as follows by the year in which such costs were incurred:

	December 31, 2008				
	Total	2008	2007	2006	Prior
	(in thousands)				
Onshore:					
Development cost	13,320	13,320	-	-	-
Exploration cost	3,555	3,555	-	-	-
Acquisition cost of undeveloped acreage	29,926	23,958	4,949	988	31
Capitalized Interest	2,552	1,978	433	141	-
	49,353	42,811	5,382	1,129	31
Offshore:					
Development cost	-	-	-	-	-
Exploration cost	-	-	-	-	-
Acquisition cost of undeveloped acreage	786	-	-	786	-
Capitalized Interest	113	-	-	113	-
	899	-	-	899	-
	50,252	42,811	5,382	2,028	31

	December 31, 2007			
	Total	2007	2006	2005
	(in thousands)			
Onshore:				
Development cost	591	591	-	-
Exploration cost	5,650	5,650	-	-
Acquisition cost of undeveloped acreage	24,995	9,023	7,568	8,404
Capitalized Interest	3,061	2,026	999	36
	34,297	17,290	8,567	8,440
Offshore:				
Development cost	-	-	-	-
Exploration cost	-	-	-	-
Acquisition cost of undeveloped acreage	6,069	209	5,860	-
Capitalized Interest	537	381	150	6
	6,606	590	6,010	6
	40,903	17,880	14,577	8,446

It is anticipated that the acquisition of undeveloped acreage and associated capitalized interest of $33.4 million and development and exploration costs of $16.9 million will be included in oil and gas properties subject to amortization within five years and one year, respectively.

Property Acquisitions. During the fourth quarter of 2008, the Company acquired a 90% working interest in a 1,280-acre position in the Pinedale Anticline in the Rockies for $35.0 million and a 70% working interest in certain properties in the Catarina Field and a 35% working interest in a significant acreage position in the Eagle Ford shale in

South Texas for $20.0 million from Pinedale Energy, LLC and CEU W&D, LLC and W&D Gas Partners, LLC, respectively.

During the second quarter of 2008, the Company acquired a 50% working interest position in approximately 12,000 gross acres in the Rockies from North American Petroleum Corporation USA, a subsidiary of Petroflow Energy Ltd. for $29.0 million.

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.

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Gas Gathering System and Compressor Stations. In December 2008 we purchased approximately 62 miles of low pressure gathering from Pacific Gas and Electric for $1.3 million. The gathering system is located in the heart of the Rio Vista field and gathers much of our low pressure production within the Rio Vista field. The gas gathering system and compressor stations of $39.8 million and $26.1 million at December 31, 2008 and 2007, respectively, are primarily located in California and the Rockies, and 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, 2008 and 2007 was $5.3 million and $3.0 million, respectively. The depreciation expense associated with the gas gathering system and compressor stations for the years ended December 31, 2008, 2007 and 2006 was $2.2 million, $1.5 million, and $1.0 million, respectively.

Other Property and Equipment. Other property and equipment at December 31, 2008 and 2007 of $9.4 million and $6.4 million, respectively, consists primarily of furniture and fixtures. The accumulated depreciation associated with other assets at December 31, 2008 and 2007 was $2.6 million and $1.4 million, respectively. For the years ended December 31, 2008, 2007 and 2006 depreciation expense for other property and equipment was $1.2 million, $0.8 million, and $0.5 million, respectively.

(5) Deferred Loan Fees

At December 31, 2008 and 2007, deferred loan fees were $1.2 million and $2.2 million, respectively. Total amortization expense for deferred loan fees was $1.0 million, $1.2 million and $1.2 million for the years ended December 31, 2008, 2007 and 2006, respectively.

(6) Commodity Hedging Contracts and Other Derivatives

The following financial fixed price swap and costless collar transactions were outstanding with associated notional volumes and average underlying prices that represent hedged prices of commodities at various market locations at December 31, 2008:

Settlement Period	Derivative Instrument	Hedge Strategy	Notional Daily Volume MMBtu	Total of Notional Volume MMBtu	Average Floor/Fixed Prices MMBtu	Average Ceiling Prices MMBtu	Natural Gas Production Hedged (1)	Fair Market Value Gain/(Loss) (In thousands)
2009	Swap	Cash flow	52,141	19,031,465	$ 7.65	$ -	37%	$ 31,082
2009	Costless Collar	Cash flow	5,000	1,825,000	8.00	10.05	4%	3,660
2010	Swap	Cash flow	10,000	3,650,000	8.31	-	9%	4,615
				24,506,465				$ 39,357

(1) Estimated based on anticipated future gas production.

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

Settlement Period	Derivative Instrument	Hedge Strategy	Average Fixed	Fair Market

			Rate	Value Gain/(Loss) (In thousands)
2009	Swap	Cash flow	4.55%	$ (985)
				$ (985)

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, 2008, 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, 2008	For the Year Ended December 31, 2007
Natural Gas		
Quantity settled (MMBtu)	26,684,616	23,464,500
Increase (decrease) in natural gas sales revenue (In thousands)	$ (18,669)	$ 22,926
Interest Rate Swaps		
Decrease (increase) in interest expense (In thousands)	$ (1,158)	$ 20

The Company expects to reclassify gains of $33.8 million based on market pricing as of December 31, 2008 to earnings from the balance in accumulated other comprehensive income (loss) on the Consolidated Balance Sheet during the next twelve months.

At December 2008, the Company had derivative assets of $39.4 million, of which $4.6 million is included in other assets on the Consolidated Balance Sheet. The Company also had derivative liabilities of $0.9 million included in current liabilities on the Consolidated Balance Sheet at December 31, 2008.

(7) Fair Value Measurements

The Company partially adopted Statement of Financial Accounting Standard No. 157, "Fair Value Measurements" ("SFAS No. 157") effective January 1, 2008. As defined in SFAS No. 157, fair value is the amount that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date ("exit price"). To estimate fair value, the Company utilizes market data or assumptions that market participants would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable, market corroborated or generally unobservable. SFAS No. 157 establishes a fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted market prices in active markets for identical assets or liabilities ("Level 1") and the lowest priority to unobservable inputs ("Level 3"). The three levels of the fair value hierarchy are as follows:

- Level 1 inputs are quoted prices (unadjusted) in active markets for identical assets or liabilities.

- Level 2 inputs are quoted prices for similar assets and liabilities in active markets or inputs that are observable for the asset or liability, either directly or indirectly through market corroboration, for substantially the full term of the financial instrument.

- Level 3 inputs are measured based on prices or valuation models that require inputs that are both significant to the fair value measurement and less observable from objective sources.

Level 3 instruments include money market funds, natural gas swaps, natural gas zero cost collars and interest rate swaps. The Company's money market funds represent cash equivalents whose investments are limited to United States Government Securities, securities backed by the United States Government, or securities of United States Government agencies. The fair value represents cash held by the fund manager as of December 31, 2008. The Company utilizes counterparty and third party broker quotes to determine the valuation of its derivative instruments. Fair values derived from counterparties and brokers are further verified using the closing price as of December 31, 2008 for the relevant NYMEX futures contracts and Intercontinental Exchange traded contracts for each derivative settlement location.

The following table sets forth by level within the fair value hierarchy the Company's financial assets and liabilities that were accounted for at fair value on a recurring basis as of December 31, 2008. As required by SFAS No. 157, financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. The Company's assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels.

	At fair value as of December 31, 2008 (In thousands)			
	Level 1	Level 2	Level 3	Total
Assets (Liabilities):				
Money market funds		-	5,025	5,025
Commodity derivative contracts	-	-	39,357	39,357
Interest rate swap contracts	-	-	(985)	(985)
Total		-	43,397	43,397

The determination of the fair values above incorporates various factors required under SFAS No. 157. These factors include the credit standing of the counterparties involved, the impact of credit enhancements and the impact of the Company's nonperformance risk on its liabilities. The Company considered credit adjustments for the counterparties using current credit default swap values and default probabilities for each counterparty in determining fair value.

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The table below presents a reconciliation for the assets and liabilities classified as Level 3 in the fair value hierarchy during 2008. Level 3 instruments presented in the table consist of net derivatives that, in management's judgment, reflect the assumptions a marketplace participant would have used at December 31, 2008.

	Derivatives Asset (Liability)	Investments	Total
		(In thousands)	
Balance as of January 1, 2008	$ (10,792)	-	(10,792)
Total (gains) losses (realized or unrealized)			
included in earnings	-	25	25
included in other comprehensive income	29,337	-	29,337
Purchases, issuances and settlements	19,827	5,000	24,827
Transfers in and out of level 3	-	-	-
Balance as of December 31, 2008	$ 38,372	$ 5,025	$ 43,397
The amount of total gains or losses for the period included in earnings attributable to the change in unrealized gains or losses relating to assets still held at December 31, 2008	$ -	$ -	$ -

(8) Accrued Liabilities

The Company's accrued liabilities consist of the following:

	December 31, 2008	December 31, 2007
	(In thousands)	
Accrued capital costs	$ 26,555	$ 34,599
Accrued purchase price adjustments	-	11,400
Accrued payroll and employee incentive expense	5,721	5,361
Accrued lease operating expense	12,196	4,930
Asset retirement obligation	1,359	4,629
Other	2,993	3,297
Total	$ 48,824	$ 64,216

(9) Asset Retirement Obligation

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

	For the Year Ended December 31, 2008	For the Year Ended December 31, 2007
	(In thousands)	
ARO as of the beginning of the period	$ 22,670	$ 10,689
Revision of previous estimate	1,785	9,751
Liabilities incurred during period	1,727	2,105

Liabilities settled during period	(363)	(1,355)
Accretion expense	2,125	1,480
ARO as of the end of the period	$ 27,944	$ 22,670

Of the total ARO, approximately $1.4 million and $4.6 million are included in accrued liabilities on the Consolidated Balance Sheet at December 31, 2008 and 2007, respectively.

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(10) Long-Term Debt

Long-term debt consists of the following:

		December 31,		
		2008		2007
		(In thousands)		
Senior secured revolving line of credit	$	225,000	$	170,000
Second lien term loan		75,000		75,000
		300,000		245,000
Less: current portion of long-term debt		-		-
	$	300,000	$	245,000

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. 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 June 2008, the borrowing base was adjusted to $400.0 million and affirmed in December 2008. The next borrowing base review is scheduled to begin on March 2, 2009. 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%. These rates over LIBOR were adjusted in June 2008 to be 1.125% to 1.875%. 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 membership interests 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. At December 31, 2008, the Company’s current ratio was 2.7 and the leverage ratio was 0.8. 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, 2008. As of December 31, 2008, the Company had $175.0 million available for borrowing under their revolving line of credit. All amounts drawn under the Revolver are due and payable on April 5, 2010.

Second Lien Term Loan. BNP Paribas, in July 2005, also provided the Company with a second lien term loan concurrent with the acquisition of oil and gas properties from Calpine (“Term Loan”). Borrowings under the Term Loan are $75.0 million as of December 31, 2008. Such borrowings are syndicated to a group of lenders including BNP Paribas. Borrowings under the Term Loan bear interest at LIBOR plus 4.00%. 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. At December 31, 2008, the Company’s asset coverage ratio was 3.1 and the leverage ratio was 0.8. 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, 2008. The principal balance of the Term Loan is due and payable on July 7, 2010.

The Company's 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 the Company's liquidity position. The Company has already begun the process of extending the maturity of its revolving credit facility and second lien term loan. If the Company is unable to extend the maturity of the revolving credit facility, it will become a current liability on April 5, 2009 and would result in the Company being in default with respect to the working capital covenants in the revolving credit facility and second lien term loan. The Company believes that it will be successful in extending this maturity on acceptable terms and conditions. Similarly, if the Company is unable to extend the maturity of the second lien term loan, it will become a current liability on July 7, 2009. Current market conditions could result in increased costs of borrowing.

Aggregate maturities of long-term debt at December 31, 2008 due in the next five years are $300 million in 2010.

(11) Commitments 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.

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Calpine Settlement

On December 20, 2005, Calpine Corporation and certain of its subsidiaries filed for protection under the federal bankruptcy laws in the Bankruptcy Court. Two years later, on December 19, 2007, the Bankruptcy Court confirmed a plan of reorganization for Calpine, which emerged from bankruptcy on January 31, 2008. During that period, on June 29, 2007, Calpine commenced the Lawsuit. Over the next fourteen months, the Company vigorously disputed Calpine's contentions in the Lawsuit, including any and all allegations that it underpaid for Calpine's oil and gas business.

On October 22, 2008, Calpine and the Company announced that they had entered into a comprehensive settlement agreement (the "Settlement Agreement") which, among other things, would (i) resolve all claims in the Lawsuit, (ii) result in Calpine conveying clean legal title on all remaining oil and gas assets to Rosetta (except those properties subject to the preferential rights of third parties who have indicated a desire to exercise their rights), (iii) settle all pending claims the Company filed in the Calpine bankruptcy, (iv) modify and extend a gas purchase agreement by which Calpine purchases the Company's dedicated production from the Sacramento Valley, California, and (v) formalize the assumption by Calpine of the July 7, 2005 purchase and sale agreement (together with all interrelated agreements, the "Purchase Agreement") by which Calpine's oil and gas business was conveyed to the Company thus resulting in the parties honoring their obligations under the Purchase Agreement on a going-forward basis. The Settlement Agreement became effective when the Bankruptcy Court entered its order on November 13, 2008, authorizing the execution of the Settlement Agreement and the performance of the obligations set forth therein. No objections or appeals to this order were filed or taken with the Bankruptcy Court before or after the hearing on November 13, 2008, and it became final on or about November 23, 2008.

The parties completed this settlement pursuant to the terms of the Settlement Agreement on December 1, 2008. The cash component of the settlement consisted of $12.4 million pre-tax payable in cash to Calpine to resolve all outstanding legal disputes regarding various matters, including Calpine's fraudulent conveyance lawsuit. In addition, the Company paid $84.6 million under the Purchase Agreement to close the original acquisition transaction of the producing properties that were the subject of the lawsuit. This $84.6 million consisted of $67.6 million, which the Company withheld from the purchase price at the closing on July 7, 2005, related to non-consent properties (excluding the properties subject to preferential rights) that were not conveyed to the Company at closing on July 7, 2005, as well as $17.0 million for various disputed post-closing adjustments under the terms of the Purchase Agreement, as amended by the Bankruptcy Court order to remove the properties that had been subject to the Petersen preferential rights as if these properties had not been part of the Purchase Agreement.

As a result of the conclusion of this settlement, the Company recorded a pre-tax charge of $12.4 million in the fourth quarter of 2008, which is included in Other Income (Expense) in the Consolidated Statement of Operations.

Arbitration between the Company and the successor to Pogo Producing Company

On October 27, 2008, the Company, Calpine and XTO, as the successor to Pogo, agreed to a Title Indemnity Agreement in which Calpine agreed to indemnify XTO for certain title disputes, and the Company, Calpine and XTO agreed to dismissal of the arbitration proceeding against the Company and release of Pogo's proofs of claim. The Company's proofs of claim were resolved within the framework of the Settlement Agreement with Calpine, which was approved by the Bankruptcy Court and an order issued in this regard. XTO has dismissed with prejudice the arbitration against the Company.

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 $3.3 million, $2.6 million and $2.4 million for the years ended December 31, 2008, 2007 and 2006, respectively.

Future minimum annual rental commitments under non-cancelable leases at December 31, 2008 are as follows (In thousands):

2009	$ 3,055
2010	2,972
2011	3,049
2012	3,074
2013	3,130
Thereafter	513
	$ 15,793

The Company also has drilling rig commitments of $5.0 million for 2009.

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(12) Stock-Based Compensation

Effective January 1, 2006, the Company began accounting for stock-based compensation under SFAS No. 123R, whereby the Company records stock-based compensation expense based on the fair value of awards described below. Stock-based compensation expense recorded for all share-based payment arrangements for the years ended December 31, 2008, 2007 and 2006 was $7.2 million, $6.8 million and $5.7 million, respectively, with an associated tax benefit of $2.9 million, $2.5 million and $2.1 million, respectively. The remaining unrecognized compensation expense associated with total unvested awards as of December 31, 2008 was $9.8 million.

2005 Long-Term Incentive Plan

In July 2005, the Board of Directors adopted the Rosetta 2005 Long-Term Incentive Plan (the “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 was increased from 3,000,000 shares to 4,950,000 shares by vote of the shareholders in 2008. The shares available for grant include these 4,950,000 shares plus any shares of common stock that become available under the Plan for any reason other than exercise, such as shares traded for the related tax liabilities of employees. The maximum number of shares of common stock available for grant of awards under the Plan to any one participant is (i) 300,000 shares during any fiscal year in which the participant begins work for Rosetta and (ii) 200,000 shares during each fiscal year thereafter.

Stock Options

The Company has granted stock options under its 2005 Long-Term Incentive Plan (the “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, 2008, 2007 and 2006 was $9.19 per share, $9.51 per share, and $10.71 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,		
	2008	2007	2006
Expected option term (years)	6.5	6.5	6.5
Expected volatility	42.45%	42.45%	56.65%
Expected dividend rate	0.00%	0.00%	0.00%
Risk free interest rate	3.48% - 3.84%	4.36% - 5.00%	4.33% - 5.15%

The Company has assumed an annual forfeiture rate of 11% for the options granted in 2008 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.

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The following table summarizes information related to outstanding and exercisable options held by the Company's employees and directors at December 31, 2008:

	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		
Granted	209,375	19.13		
Exercised	(214,119)	16.89		
Forfeited	(26,100)	17.57		
Outstanding at December 31, 2008	941,756	$ 17.94		
Options Vested and Exercisable at December 31, 2008	629,155	$ 17.76	7.34	$ -

Stock-based compensation expense recorded for stock option awards for the years ended December 31, 2008, 2007 and 2006 was $1.7 million, $3.9 million and $2.9 million, respectively. Unrecognized expense as of December 31, 2008 for all outstanding stock options is $1.4 million and will be recognized over a weighted average period of 0.92 years.

The total intrinsic value of options exercised during the years ended December 31, 2008, 2007 and 2006 is $1.4 million, $0.2 million and $0.1 million, respectively.

Restricted Stock

The Company has granted restricted 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 11% 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 and directors at December 31, 2008:

	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
Granted	607,079		20.06
Vested	(274,714)		18.31
Forfeited	(70,351)		19.54
Non-vested shares outstanding at December 31, 2008	717,439	$	19.78

The non-vested restricted stock outstanding at December 31, 2008 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, 2008 was $6.2 million.

Stock-based compensation expense recorded for restricted stock awards for the years ended December 31, 2008, 2007 and 2006 was $5.5 million, $2.9 million and $2.8 million, respectively. Unrecognized expense as of December 31, 2008 for all outstanding restricted stock awards is $8.5 million and will be recognized over a weighted average period of 1.78 years.

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(13) Income Taxes

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

	Year Ended December 31, 2008	2007	2006
	(In thousands)		
Current:			
Federal	$ 2,304	$ -	$ -
State	1,388	115	172
	3,692	115	172
Deferred:			
Federal	(107,568)	31,979	24,132
State	(8,951)	1,938	3,340
	(116,519)	33,917	27,472
Total income tax expense (benefit)	$ (112,827)	$ 34,032	$ 27,644

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:

	Year Ended December 31, 2008 (In thousands)	(%)	2007 (In thousands)	(%)	2006 (In thousands)	(%)
US Statutory Rate	$ (105,327)	35.0%	$ 31,933	35.0%	$ 25,288	35.0%
Income/franschise tax, net of federal benefit	(7,562)	2.5%	2,053	2.3%	2,283	3.2%
Permanent differences and other	62	0.0%	46	0.0%	73	0.0%
Total tax expense (Benefit)	$ (112,827)	37.5%	$ 34,032	37.3%	$ 27,644	38.2%

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.

The components of deferred taxes are as follows:

	December 31, 2008	2007
	(In thousands)	
Deferred tax assets		
Oil and gas properties basis differences	$ 39,089	$ -
Alternative Minimum Tax credit	2,443	-

Accrued liabilities not currently deductible	2,603	3,273
Hedge activity	-	4,289
Net operating loss carryforward	621	12,506
Other	1,158	892
Total deferred tax assets	45,914	20,960
Oil and gas properties basis differences	-	(89,397)
Hedge activity	(14,294)	-
Other	(1,543)	(200)
Total gross deferred tax liabilities	(15,837)	(89,597)
Net deferred tax assets (liabilities)	$ 30,077	$ (68,637)

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At December 31, 2008, the Company had a deferred tax asset related to federal and state net operating loss carryforwards of approximately $1.5 million. The net operating loss carryforward will begin to expire in 2025. Additionally, the Company had a deferred tax asset related to oil and gas properties basis of $39.1 million. 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.

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, 2008 and 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:

	Year Ended December 31,		
	2008	2007	2006
		(In thousands)	
Basic weighted average number of shares outstanding	50,693	50,379	50,237
Dilution effect of stock option and awards at the end of the period	-	210	171
Diluted weighted average number of shares outstanding	50,693	50,589	50,408
Anti-dilutive stock options and awards	592	385	198

Because the Company recognized a net loss for the year ended December 31, 2008, no unvested stock awards and options were included in computing earnings per share because the effect was anti-dilutive. In computing earnings per share, no adjustments were made to reported net income.

(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.

	Year Ended December 31,		
	2008 (1)	2007 (1)	2006 (1)
Oil and Natural Gas Revenue		(In thousands)	
California	$ 141,569	$ 110,607	$ 76,408
Rockies	29,491	10,676	2,115
South Texas	204,791	143,886	100,988
Texas State Waters	49,745	8,789	8,183
Other Onshore	44,809	25,905	27,757
Gulf of Mexico	47,611	40,700	26,734
	$ 518,016	$ 340,563	$ 242,185

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	December 31, 2008	December 31, 2007
Oil and Natural Gas Properties	(In thousands)	
California	$ 619,593	$ 540,924
Rockies	175,294	76,343
South Texas	712,464	591,355
Texas State Waters	65,085	55,918
Other Onshore	171,855	145,675
Gulf of Mexico	156,381	155,867
Other	9,439	6,393
	$ 1,910,111	$ 1,572,475

(1) Excludes the effects of hedging losses of $18.7 million for the year ended December 31, 2008 and hedging gains of $22.9 million and $29.6 million for the years ended December 31, 2007 and 2006, respectively.

Major Customers

For the year ended December 31, 2008, the Company had one major customer, Calpine Energy Services ("CES"), a Calpine affiliate, which accounted for approximately 61% of the Company's consolidated annual revenue. The Company's annual consolidated revenue from CES accounted for approximately 55% for the year ended December 31, 2007 and 45% for the year ended December 31, 2006, respectively, and is reflected in oil and natural gas sales.

For the years ended December 31, 2008, 2007 and 2006, revenues from sales to CES were $305.9 million, $201.4 million, and $99.1 million, respectively. There was no receivable from CES at December 31, 2008 or 2007. 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, 2008 and 2007, the Company had $19.4 million and $20.4 million in the margin account for December sales to CES which is included in Accrued Liabilities on the Consolidated Balance Sheet.

Marketing Services Agreement

The Company entered into a new marketing services agreement ("MSA") with Calpine Producer Services ("CPS") in connection with the partial transfer and release agreement ("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%, subject to caps imposed under the MSA. For the years ended December 31, 2008, 2007 and 2006, the fee was approximately $3.1 million, $2.5 million, and $2.3 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. The MSA will expire in June 2009 and the Company does not have intentions of renewing the MSA. The Company is expanding its internal capabilities in this regard so as to be able to market in-house all of its oil and gas production at the conclusion of the MSA.

(16) Related Party Transactions

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 former 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.

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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, 2008, 2007, and 2006, 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 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 qualified, 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, 2008 and 2007:

	2008	2007
	(In thousands)	
Proved properties	$ 1,813,527	$ 1,499,046
Unproved properties	50,252	40,903
Total	1,863,779	1,539,949
Less: Accumulated depreciation, depletion, and amortization	(927,961)	(291,321)
Net capitalized costs	$ 935,818	$ 1,248,628

Pursuant to SFAS No. 143 "Accounting for Asset Retirement Obligations", net capitalized costs include asset retirement costs of $23.2 million and $20.1 million as of December 31, 2008 and 2007, 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, 2008, 2007 and 2006:

	Year Ended December 31,		
	2008	2007	2006
		(In thousands)	
Acquisition costs of properties			
Proved	$ 103,177	$ 40,760	$ 39,194
Unproved	32,276	23,824	22,317
Subtotal	135,453	64,584	61,511
Exploration costs	35,735	90,117	48,446
Development costs	152,260	178,894	125,971
Total	$ 323,448	$ 333,595	$ 235,928

Results of operations for oil and natural gas producing activities

	Year Ended December 31,		
	2008 (1)	2007 (1)	2006 (1)
Oil and natural gas producing revenues	$ 518,016	$ 340,563	$ 242,185
Total Revenues	518,016	340,563	242,185
Production costs	78,609	60,140	47,507
Depreciation, depletion, and amortization	198,862	152,882	105,886
Impairment of oil and gas properties	444,369	-	-
Income before income taxes	(203,824)	127,541	88,792
Income tax provision	(76,434)	47,573	34,007
Results of operations	$ (127,390)	$ 79,968	$ 54,785

(1)

Excludes the effects of hedging losses of $18.7 million for the year ended December 31, 2008 and hedging gains of $22.9 million and $29.6 million for the years ended December 31, 2007 and 2006, respectively.

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.

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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, 2008, 2007, and 2006, as estimated by the independent petroleum consultants and the changes in the net proved reserves for each of the three years then ended.

	Natural gas (Bcf)(1):	Natural gas liquids and crude oil (MBbl)(2)(3):	Bcfe (1) equivalents (4):
Net proved reserves at December 31, 2005 (5)	345	2,481	359
Revisions of previous estimates	(10)	424	(7)
Purchases in place	4	286	6
Extensions, discoveries and other additions	81	315	83
Sales in place	-	-	-
Production	(30)	(576)	(33)
Net proved reserves at December 31, 2006 (5)	390	2,930	408
Revisions of previous estimates	(30)	-	(30)
Purchases in place	10	-	10
Extensions, discoveries and other additions	72	652	76
Sales in place	-	-	-
Production	(42)	(561)	(46)
Net proved reserves at December 31, 2007 (5)	400	3,021	418
Revisions of previous estimates (6)	(77)	779	(72)
Purchases in place	63	293	65
Extensions, discoveries and other additions	38	418	40
Sales in place	-	-	-
Production	(48)	(908)	(53)
Net proved reserves at December 31, 2008	376	3,603	398

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, 2006 (5)	251	1,965	263
December 31, 2007 (5)	286	2,658	302
December 31, 2008	308	3,253	327

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

(6) Downward revision of 64 Bcfe of proved reserves and 8 Bcfe due to year-end commodity prices.

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.

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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, 2008, 2007 and 2006.

	Year Ended December 31,		
	2008	2007	2006
	(In millions)		
Future cash inflows	$ 2,437	$ 3,026	$ 2,452
Future production costs	(776)	(819)	(684)
Future development costs	(269)	(302)	(312)
Future income taxes	(166)	(323)	(182)
Future net cash flows	1,226	1,582	1,274
Discount to present value at 10% annual rate	(485)	(628)	(552)
Standardized measure of discounted future net cash flows relating to proved natural gas, natural gas liquids and crude oil reserves	$ 741	$ 954	$ 722

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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, 2008, 2007 and 2006.

	(In millions)
Balance December 31, 2005 (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 (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 (1)	954
Sales and transfers of natural gas, natural gas liquids and crude oil produced, net of production costs	(439)
Net changes in prices and production costs	(73)
Extensions, discoveries, additions and improved recovery, net of related costs	123
Development costs incurred	98
Revisions of previous quantity estimates and development costs	(191)
Accretion of discount	114
Net change in income taxes	95
Purchases of reserve in place	119
Sales of reserves in place	-
Changes in timing and other	(59)
Balance December 31, 2008	$ 741

(1) Excludes non-consent properties - see Note 11.

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Rosetta Resources Inc.
Selected Data
Quarterly Information
(Unaudited)

Summaries of the Company's results of operations by quarter for the years ended 2008 and 2007 are as follows:

	2008			
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(In thousands, except per share data)			
Revenues	$ 128,333	$ 154,467	$ 130,036	$ 86,512
Impairment of oil and gas properties	-	-	(205,659)	(238,710)
Operating Income	45,908	66,730	(155,806)	(232,170)
Net Income	27,489	39,315	(99,375)	(155,539)
Basic earnings per share	$ 0.54	$ 0.78	$ (1.96)	$ (3.06)
Diluted earnings per share	$ 0.54	$ 0.77	$ (1.96)	$ (3.06)

	2007			
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(In thousands, except per share data)			
Revenues	$ 75,796	$ 86,874	$ 89,718	$ 111,101
Impairment of oil and gas properties	-	-	-	-
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

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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, 2008. 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 (i) recorded, processed, summarized and reported within the time periods specified in Securities and Exchange Commission’s rules and forms, and (ii) 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, 2008, our disclosure controls and procedures were effective.

Management’s Annual 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, 2008 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, 2008, 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, 2008, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report, which is included in Item 8. Financial Statements and Supplementary Data 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, 2008 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

Item 9B. Other Information

Item 5.02(e). Departure of Directors or Certain Officers; Election of Directors; Appointment of Certain Officers; Compensatory Arrangements of Certain Officers.

On February 23, 2009, the Compensation Committee amended and restated the 2005 Long-Term Incentive Plan. The amended and restated 2005 Long-Term Incentive Plan is attached hereto as Exhibit 10.9. These amendments were not material. Additionally, on February 23, 2009, the Compensation Committee adopted the 2005 Long-Term Incentive Plan Performance Share Unit Award Agreement which is attached hereto as Exhibit 10.39. This is a form of agreement for performance share unit awards to be made under the 2005 Long-Term Incentive Plan. Because this

Annual Report on Form 10-K is being filed within four business days from February 23, 2009, the amendment and restatement of the 2005 Long-Term Incentive Plan and the adoption of the 2005 Long-Term Incentive Plan Performance Share Unit Award Agreement are being disclosed hereunder rather than under Item 5.02(e) of Form 8-K.

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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 to our definitive proxy statement to be filed with respect to our 2009 annual meeting under the headings “Security Ownership of Directors and Executive Officers,” “Company Nominees for Director,” “Section 16(a) Beneficial Ownership Reporting Compliance,” and “Corporate Governance and Committees of the Board.”

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 2009 annual meeting under the headings “Executive Compensation,” “Information Concerning the Board of Directors,” and “Compensation Committee Report.”

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 2009 annual meeting under the headings ”Security Ownership of Certain Beneficial Owners and Management” and “Securities Authorized for Issuance Under Equity Compensation Plans.”

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 2009 annual meeting under the heading “Certain Transactions” and “Corporate Governance and Committees of the Board.”

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 2009 annual meeting under the heading “Audit and Non-Audit Fees Summary.”

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Part IV

Item 15. Exhibits and Financial Statement Schedules

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

(1) Our Consolidated Financial Statements are listed on page 42 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	Amended and Restated Bylaws (incorporated herein by reference to Exhibit 3.2 to the Company's Current Report on Form 8-K filed on December 10, 2008 (Registration No. 000-51801)).
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10.3*	Settlement Agreement and Amendment with Calpine Corporation attached hereto as Exhibit 10.3.
10.4*	Amended and Restated Base Contract for Sale and Purchase of Natural Gas with Calpine Energy Services, L.P. attached hereto as Exhibit 10.4.
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21.1*	Subsidiaries of the registrant

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* Filed herewith

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

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Signatures

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized, on February 27, 2009.

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 27, 2009
/s/ Michael J. Rosinski Michael J. Rosinski	Executive Vice President and Chief Financial Officer (Principal Financial Officer)	February 27, 2009
/s/ Denise DuBard Denise DuBard	Vice President, Controller (Principal Accounting Officer)	February 27, 2009
/s/ D. Henry Houston D. Henry Houston	Non-Executive Chairman, Director	February 27, 2009
/s/ Richard W. Beckler Richard W. Beckler	Director	February 27, 2009
/s/ Matt Fitzgerald Matt Fitzgerald	Director	February 27, 2009
/s/ Philip L. Frederickson Philip L. Frederickson	Director	February 27, 2009
/s/ Josiah O. Low, III Josiah O. Low, III	Director	February 27, 2009
/s/ Donald D. Patteson, Jr. Donald D. Patteson, Jr.	Director	February 27, 2009

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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.

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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.

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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