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

FORM 10-K

ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF
THE SECURITIES EXCHANGE ACT OF 1934

FOR THE FISCAL YEAR ENDED DECEMBER 31, 2009

Commission File Number 001-14039

CALLON PETROLEUM COMPANY

(Exact name of Registrant as specified in its charter)

Delaware	64-0844345
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
200 North Canal Street Natchez, Mississippi 39120	**(601) 442-1601**
(Address of Principal Executive Offices) (Zip Code)	(Registrant's telephone number including area code)

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of exchange on which registered
Common Stock, Par Value $.01 Per Share	New York Stock Exchange

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 ☑.

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☐ 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 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 definitions of "Large accelerated filer, accelerated filer and smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer ☐ Accelerated filer ☐ Non-accelerated filer ☑ (Do not check if a smaller reporting company) Smaller reporting Company ☐

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

The aggregate market value of the voting and non-voting common equity held by nonaffiliates of the registrant was approximately $41 million as of June 30, 2009 (based on the last reported sale price of such stock on the New York Stock Exchange on such date of $1.98).

As of March 8, 2010, there were 28,740,863 shares of the Registrant's Common Stock, par value $.01 per share, outstanding.
Document incorporated by reference: Portions of the definitive Proxy Statement of Callon Petroleum Company (to be filed no later than 120 days after December 31, 2009) relating to the Annual Meeting of Stockholders to be held on May 4, 2010, which are incorporated into Part III of this Form 10-K.

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PART I.

ITEM 1 and 2. BUSINESS and PROPERTIES

Overview

Callon Petroleum Company was incorporated under the laws of the state of Delaware in 1994 and succeeded to the business of a publicly traded limited partnership, a joint venture with a consortium of European investors and an independent energy company partially owned by a member of current management. As used herein, the "Company," "Callon," "we," "us," and "our" refer to Callon Petroleum Company and its predecessors and subsidiaries unless the context requires otherwise.

Prior to 2009, our operations were focused on exploration and production in the Gulf of Mexico. Following the abandonment of our Entrada project in 2008, we took steps to change our operational focus to lower risk, onshore exploration and development activities. During 2009, we took the following actions:

- We exchanged a new series of senior notes due 2016 and common stock for a substantial portion of our existing $200 million of senior notes due 2010, and reduced principal from $200 million to $154 million.
- We filed for recoupment of deepwater royalty payments, and received a payment from the Minerals Management Service ("MMS") of $44.8 million in January 2010. We expect to receive an additional payment from the MMS of approximately $7.7 million during 2010, representing interest.
- We began negotiating a new $100 million revolving credit facility, with a borrowing base of $20 million, which we finalized in January 2010.

These activities were undertaken to allow us to shift our operational focus from the offshore Gulf of Mexico to longer life, lower risk onshore properties. As part of this strategy, we employed Steven B. Hinchman as our Chief Operating Officer. Mr. Hinchman has substantial experience in onshore oil and gas acquisition, exploration and development activities. During 2009, we closed two acquisitions as part of this new focus, including:

- In September 2009, we acquired a 70% working interest in a 577-acre unit in the heart of the Haynesville Shale play in Bossier Parish, Louisiana for $3.0 million. We plan to drill a total of seven horizontal wells on this property, with the first two wells to be drilled in 2010. We will be the operator of these wells.
- On October 28, 2009, we acquired interests in properties producing from the Wolfberry formation in Crockett, Ector, Midland and Upton Counties, Texas for total cash consideration of $16.0 million. The acquisition included year-end proved reserves of 1.6 million barrels of oil equivalent ("MMBoe") 22 existing wells producing 350 barrels of oil equivalent ("Boe") per day and upside from a multi-year inventory of drilling opportunities. We will operate substantially all of the production and development of these properties. See Note 13 to our Consolidated Financial Statements.

Our Business Strategy

Our strategy for 2010 and going forward will be,

- To increase reserves and production levels by using cash flows from, or monetization of, our Gulf of Mexico properties to acquire and develop lower risk, longer life onshore oil and gas properties;
- To increase our reserve life by focusing on acquisition of long-life onshore properties;
- To diversify risk by substantially increasing the number of wells we own; and
- To strengthen our balance sheet by focusing on a reduction of our average debt per thousand cubic feet of natural gas equivalent ("Mcfe") of proved reserves.

Exploration and Development Activities

In 2009, capital expenditures on an accrual basis for exploration and development costs related to oil and gas properties totaled approximately $40 million. These expenditures included:

- $19 million for on-shore property acquisitions;
- $2 million for development costs in the Gulf of Mexico and onshore south Louisiana;
- $6 million for plugging and abandonment costs in the Gulf of Mexico; and
- $3 million for capitalized interest and $10 million for capitalized general and administration costs allocable directly to exploration and development projects.

Acquisitions and Divestitures

In September 2009, we acquired a 70% operating interest in a 577-acre Haynesville Shale Unit in Bossier Parish, Louisiana at a cost of $3.0 million. The Unit is in the core of the play offset by wells having demonstrated initial production rates of 20 million cubic feet of natural gas ("MMcf") per day. We plan to drill and complete two of seven horizontal wells in 2010. We estimate that the typical well in this field will have gross recoverable reserves of 6.4 billion cubic feet of natural gas ("Bcf") per well and cost approximately $9.0 million to drill and complete. Callon will be the operator of this project.

On October 28, 2009, we completed the acquisition of proved oil and gas property interests in Wolfberry play located in Crockett, Ector, Midland and Upton Counties, Texas from Ambrose Energy I, Ltd., a subsidiary of ExL Petroleum, LP for a total cash consideration of $16.0 million. The acquisition was funded by our senior secured credit facility in the amount of $10 million, and the remaining $6.0 million with cash on hand. The acquisition included year-end proved reserves of 1.6 MMBoe, 22 existing wells producing 350 Boe per day and upside from a multi-year inventory of drilling and recompletion opportunities. We will operate substantially all of the production and development. We accounted for the acquisition in accordance with the amended guidance issued by the Financial Accounting Standards Board ("FASB") for business combinations which was adopted on January 1, 2009, and recorded acquisition expenses in the fourth quarter of 2009 of $298,000. See Note 13 to our Consolidated Financial Statements.

Oil and Gas Properties Summary

Overview. As of December 31, 2009, our estimated net proved reserves totaled 58.0 billion cubic feet of natural gas equivalent ("Bcfe") and included 6.5 million barrels of oil ("MMBbls") and 19.1 Bcf, with a pre-tax present value of $137.4 million. Pre-tax present value may be deemed to be a non-U.S. generally accepted accounting principle ("US GAAP") financial measure, which we reconcile to standardized measure, the US GAAP measure, in the table below. Oil constitutes approximately 67% on an equivalent basis of our total estimated net proved reserves, and approximately 66% of our total estimated proved reserves are proved developed reserves.

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The following table sets forth certain information about our estimated proved reserves by our independent petroleum reserve engineers by major field and for all other properties combined at December 31, 2009.

	Operator	Estimated Net Proved Reserves Oil (MBbls)	Gas (MMcf)	Total (MMcfe)	Pre-tax Discounted Present Value ($000) (a)(b)(c)
Gulf of Mexico Deepwater:					
Mississippi Canyon 538/582					
"Medusa"	Murphy	4,412	3,268	29,740	$ 89,795
Garden Banks Block 341					
"Habanero"	Shell	725	4,729	9,077	25,084
Gulf of Mexico Shelf and Onshore:					
West Cameron Block 295	Mariner Energy	12	1,724	1,798	3,402
East Cameron Block 109	Energy Partners LTD	18	1,224	1,332	4,193
Permian Basin	Callon	1,242	2,117	9,571	17,873
Other	Various	70	6,041	6,457	(2,979)
Total Net Proved Reserves		6,479	19,103	57,975	$ 137,368

(a) Represents the present value of future net cash flows before deduction of federal income taxes, discounted at 10%, attributable to estimated net proved reserves as of December 31, 2009, as set forth in the Company's reserve reports prepared by its independent petroleum reserve engineers, Huddleston & Co., Inc.

(b) Includes a reduction for estimated plugging and abandonment costs that is reflected as a liability on our balance sheet at December 31, 2009, in accordance with accounting for asset retirement obligations rules. See the Oil and Gas Reserve table for the standardized measure of discounted future net cash flow in Note 18 of our consolidated financial statements. The negative Pre-Tax Present Value of the Gulf of Mexico Shelf and Onshore Other reflects plugging and abandonment obligations, of which most are estimated to occur within the next five years, exceeding the future net cash flows.

(c) We use the financial measure "Pre Tax Present Value" which is a non-US GAAP financial measure. We believe that Pre Tax Present Value, while not a financial measure in accordance with US GAAP, is an important financial measure used by investors and independent oil and gas producers for evaluating the relative value of oil and natural gas properties and acquisitions because the tax characteristics of comparable companies can differ materially. The total standardized measure for our proved reserves as of December 31, 2009 was $135.9 million. The standardized measure gives effect to income taxes, and is calculated in accordance with the guidance issued by the FASB for disclosures about oil and gas producing activities." The $135.9 million of standardized measure of our estimated net proved reserves equals the present value of our estimated future net revenue from proved reserves of $137.4 million, which excludes the discounted estimated future income taxes relating to such future net revenues of $1.5 million.

Onshore Oil and Gas Properties

Permian Basin

During the fourth quarter of 2009, we acquired 22 producing wells with associated proved reserves of 1.6 MMBoe. Our primary target in the Permian Basin is the Wolfberry trend, which is a proven, low-permeability oil play. The Wolfberry interval includes the Sprayberry, Dean, and Wolfcamp formations. We have identified 148 drilling locations based on a 40-acre spacing development. We commenced drilling in February 2010 and plan to drill up to 16 Wolfberry wells in 2010.

Haynesville Shale

In addition to the significant properties discussed above, we acquired a 70% working interest in a Haynesville Shale unit located in Southern Bossier Parish, Louisiana in September 2009. We plan to drill two horizontal wells in 2010.

Gulf of Mexico Deepwater

Medusa, Mississippi Canyon Blocks 538/582

Our Medusa deepwater discovery was announced in September 1999, after we drilled the initial test well in 2,235 feet of water to a total depth of 16,241 feet and encountered over 120 feet of pay in two intervals. Subsequent sidetrack drilling from the wellbore was used to determine the extent of the discovery, and a second well was drilled in the first quarter of 2000 to further delineate the extent of the pay intervals. In 2001, a drilling program began which included four development wells and one sidetrack. The program included production casing being set on six wells to provide initial production take-points and was completed in the first half of 2002. The construction of a floating production system, spar, at Medusa was completed during the second quarter of 2003. The A-1 well was completed and tied into the spar and commenced production in late November 2003. The remaining five wells were completed and commenced production in 2004. We have participated in additional development of the Medusa field which includes the drilling and completion of two additional wells, Mississippi Canyon 538 #4, North Medusa, and Mississippi Canyon 538 #5. We own a 15% working interest. Murphy Exploration & Production Company ("Murphy"), the operator, owns a 60% working interest and ENI Deepwater, LLC, owns the remaining 25% working interest.

During 2009 the field produced 4.5 Bcfe net to us from eight wells which accounted for 38% of our total production. Inception to date as of December 31, 2009, the Medusa Field had produced 43 Bcfe, net to us. Most of the wells are still producing from their initial completion and have 14.2 Bcfe of proved developed non-producing reserves that will be accessed by recompletions in the existing wells. Another 7.1 Bcfe of proved undeveloped reserves will be developed by side tracking an existing well. These operations will occur as existing completions reach their economic limit which is estimated as of December 31, 2009 to be in 2022.

In December 2003, we transferred our undivided 15% working interest in the spar production facilities to Medusa Spar LLC ("LLC") in exchange for cash proceeds of approximately $25 million and a 10% ownership interest in the LLC. A detailed discussion of this transaction is included in "Management's Discussion and Analysis of Financial Condition and Results of Operations-Off-Balance Sheet Arrangements."

Habanero, Garden Banks Block 341

During February 1999, the initial test well on our Habanero deepwater discovery encountered over 200 feet of net pay in two zones. Located in 2,015 feet of water, the well was drilled to a measured depth of 21,158 feet. A field delineation program began in mid-year 2001, which included three sidetracks of the discovery well. Production casing was set on this well through the last of the sidetracks to the Habanero 52 oil and gas sand and the Habanero 55 gas sand. Also, a development well was drilled in the summer of 2003 which provides a take-point for production from the Habanero 52 oil sand. By means of a sub-sea completion and tie-back to an existing production facility in the area operated by Shell, production from the Habanero 52 oil sand commenced in late November 2003 and from the Habanero 55 gas sand in January 2004. We own an 11.25% working interest in the well. The well is operated by Shell Deepwater Development Inc., which owns a 55% working interest, with the remaining working interest owned by Murphy.

During 2009, Habanero produced 2.2 Bcfe net to us from two wells which accounted for 19% of our total production. Future plans include sidetracks of both the wells to drain updip and partially fault-separated gas in the Habanero 52 sand when the existing completions reach their economic limit, which is estimated as of December 31, 2009 to be in 2014.

Gulf of Mexico Shelf and Onshore Louisiana

We own interests in 18 wells in 12 oil and gas fields in the shelf area of the Gulf of Mexico. These wells produced 5.0 Bcfe net to our interest in 2009.

Proved Reserves

In December 2008 the Securities and Exchange Commission (“SEC”) approved amendments to its oil and gas reserves estimation and disclosure requirements. The amendments, among other things:

- allow the use of reliable technologies to estimate proved reserves if those technologies have been demonstrated to result in reliable conclusions about reserve volumes;
- require disclosure of oil and gas proved reserves by significant geographic area;
- permit the optional disclosure of probable and possible reserves;
- modify the prices used to estimate reserves for SEC disclosure purposes to a 12-month average beginning-of-the-month price instead of a period-end price; and
- require that if a third party is primarily responsible for preparing or auditing the reserve estimates, the company make disclosures relating to the independence and qualifications of the third party, including filing as an exhibit any report received from the third party.

The new requirements are effective for our year-end financial statements and our Annual Report on Form 10-K for the year ended December 31, 2009, and as such the reserves and related information for 2009 are presented consistent with the requirements of the new rule. The new rule does not require prior-year reserve information to be restated, so all information related to periods prior to 2009 is presented consistent with the prior SEC rules for the estimation of proved reserves.

Estimates of volumes of proved reserves, net to our interest, at year end are presented in Mmcf at a pressure base of 15.025 pounds per square inch for natural gas and in MBbls for oil. Total volumes are presented in million cubic feet of natural gas equivalent (“MMcfe”). For the computation, one barrel is the equivalent of 6,000 cubic feet of gas.

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The following table sets forth certain information about our estimated proved reserves. All of our proved reserves are located in the United States.

	Years Ended December 31,		
	2009	**2008**	**2007**
Proved developed:			
Oil (MBbls)	4,346	4,663	4,723
Gas (MMcf)	12,301	13,463	22,340
MMcfe	38,377	41,441	50,676
Proved undeveloped:			
Oil (MBbls) (c)	2,133	1,364	19,808
Gas (MMcf) (c)	6,802	5,189	94,114
MMcfe (c)	19,600	13,375	212,964
Total proved:			
Oil (MBbls) (c)	6,479	6,027	24,531
Gas (MMcf) (c)	19,103	18,652	116,454
MMcfe (c)	57,977	54,816	263,640
Estimated pre-tax future net cash flows (a)	$216,702	$113,555	$2,317,905
Pre-tax discounted present value (a) (b)	$137,368	$ 86,591	$1,591,472
Standardized measure of discounted future net cash flows(a) (b)	$135,921	$ 86,305	$1,133,989

(a) Includes a reduction for estimated plugging and abandonment costs that is reflected as a liability on our balance sheet at December 31, 2009, in accordance with accounting for asset retirement obligations rule.

(b) We use the financial measure "Pre Tax Present Value" which is a non-US GAAP financial measure. We believe that Pre Tax Present Value, while not a financial measure in accordance with US GAAP, is an important financial measure used by investors and independent oil and gas producers for evaluating the relative value of oil and natural gas properties and acquisitions because the tax characteristics of comparable companies can differ materially. The total standardized measure for our proved reserves as of December 31, 2009 was $135.9 million. The standardized measure gives effect to income taxes, and is calculated in accordance with guidance issued by the FASB for disclosures about oil and gas producing activities. The $135.9 million of standardized measure of our estimated net proved reserves equals the present value of our estimated future net revenue from proved reserves of $137.4 million, which excludes the discounted estimated future income taxes relating to such future net revenues of $1.5 million. Year-end average pricing was $4.75 per Mcf for natural gas and $57.40 per Bbl for oil.

(c) The reduction in 2008 reserves as compared to 2007 year-end proved reserves of 263.6 Bcfe was primarily associated with the sale of a 50% working interest in the Entrada Field and the abandonment of the Entrada project. See Note 3 to our consolidated financial statements.

Our estimates of proved reserves, proved developed reserves ("PDPs"), proved undeveloped reserves ("PUDs") at December 31, 2009, 2008 and 2007 and changes in proved reserves during the last three years are included in Note 18 of our Consolidated Financial Statements. Also included in Note 18 are our estimates of future net cash flows and discounted future net cash flows from proved reserves.

Proved Undeveloped Reserves. We annually review our PUDs to ensure an appropriate plan exists for development. Generally, reserves for our onshore properties are booked as PUDs only if we have plans to convert the PUDs into PDPs within five years of the date they are first booked as PUDs. We had 19.6 Bcfe of PUDs at December 31, 2009, compared with 13.4 Bcfe of PUDs at December 31, 2008. Of these 2009 PUDs, 7.1 Bcfe and 6.9 Bcfe were attributable to our offshore properties in the Medusa and Habanero fields in the Gulf of Mexico, respectively. Our plans are to develop these PUDs by side tracking existing wells when the zones currently being produced by the wells are depleted. Our current reserve reports forecast that these producing zones in the Habenero field will be depleted in 2014 and in the Medusa field in 2022, at which time we plan to develop the PUDs. We did not convert any offshore PUDs to PDPs in 2009.

During 2009, we acquired 711 MBbls and 1.3 Bcf, or 5.6 Bcfe, of PUDs in our ExL acquisition. Our development plan for these PUDs will begin in 2010 and are anticipated to be completed within five years allowing the PUDs to be converted to PDPs. The remaining 0.6 Bcfe increase in PUDs from 2008 to 2009 is associated with our deepwater property, Medusa, and is a result of including reserves related to the Deepwater Royalty Relief Act. These PUDs were previously excluded due to prices exceeding the MMS imposed thresholds. As a result of the court decisions, the MMS is no longer enforcing its price thresholds. At year end 2008, we had no PUDs located onshore. See Note 12 to our Consolidated Financial Statements.

Controls Over Reserve Estimates. Our policies and practices regarding internal controls over the recording of reserves are structured to objectively and accurately estimate our oil and gas reserves quantities and present values in compliance with the SEC's regulations and US GAAP. Compliance in reserves bookings is the responsibility of our Executive Vice President and Chief Operating Officer, who is our principal engineer. Our principal engineer has over 30 years of experience in the oil and gas industry, including over 25 years as a manager. Further professional qualifications include a degree in petroleum engineering and asset evaluation and management. In addition, the principal engineer is an over 30-year member of the Society of Petroleum Engineers.

Our controls over reserve estimates included retaining Huddleston & Co. as our independent petroleum and geological firm. We provided information about our oil and gas properties, including production profiles, prices and costs, to Huddleston and they prepare their own estimates of the reserves attributable to our properties. All of the information regarding reserves in this annual report is derived from the report of Huddleston. The report of Huddleston is included as an Exhibit to this annual report. The principal engineer at Huddleston who is responsible for preparing our reserve estimates has over 29 years of experience in the oil and gas industry and is a Texas Licensed Professional Engineer. Further professional qualifications include a degree in petroleum engineering as well as being a member of the Society of Petroleum Engineers. The Huddleston & Co., Inc. engineer firm is a Texas Registered Engineering Firm.

The Audit Committee of our Board of Directors meets with management, including the Chief Operating Officer to discuss matters and policies including those related to reserves.

There are numerous uncertainties inherent in estimating quantities of proved reserves, including many factors beyond our control or the control of the reserve engineers. Reserve engineering is a subjective process of estimating underground accumulations of oil and gas that cannot be measured in an exact manner. The accuracy of any reserve or cash flow estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. Estimates by different engineers often vary, sometimes significantly. In addition, physical factors, such as the results of drilling, testing and production subsequent to the date of an estimate, as well as economic factors, such as an increase or decrease in product prices that renders production of such reserves more or less economic, may justify revision of such estimates. Accordingly, reserve estimates could be different from the quantities of oil and gas that are ultimately recovered.

During our last fiscal year, we have not filed any reports with other federal agencies which contain an estimate of total proved net oil and gas reserves.

Production Volumes, Average Sales Prices and Average Production Costs

The following table sets forth certain information regarding the production volumes and average sales prices received for and average production costs associated with the Company's sale of oil and natural gas for the periods indicated.

	Year ended December 31,		
	2009	2008	2007
	(In thousands, except per unit data)		
Production			
Natural gas (Mcf)	5,740	5,839	12,340
Oil (MBbl)	1,012	942	1,063
Total (MMcfe)	11,809	11,494	18,718
Revenues			
Natural gas sales	$ 27,417	$ 58,349	$ 98,877
Oil sales	73,842	82,963	71,891
Total revenues	$101,259	$141,312	$170,768
Lease Operating Expenses			
Production costs	$ 16,778	$ 17,604	$ 24,254
Severance/production taxes	528	626	1,378
Gathering	1,141	977	2,162
Total lease operating expenses	$ 18,447	$ 19,208	$ 27,795
Realized prices			
Natural gas ($/Mcf, including realized gains (losses) on derivatives)	$ 4.78	$ 9.99	$ 8.01
Natural gas ($/Mcf, excluding realized gains (losses) on derivatives)	$ 4.45	$ 10.10	$ 7.40
Oil ($/Bbl, including realized gains (losses) on derivatives)	$ 73.00	$ 88.07	$ 67.63
Oil ($/Bbl, excluding realized gains (losses) on derivatives)	$ 55.84	$ 97.37	$ 67.10
Operating costs per Mcfe — Total Consolidated			
Production costs	$ 1.42	$ 1.53	$ 1.30
Severance/production taxes	$ 0.04	$ 0.05	$ 0.07
Gathering	$ 0.10	$ 0.09	$ 0.12
DD&A	$ 2.83	$ 5.57	$ 3.89
Interest	$ 1.62	$ 2.09	$ 1.83
Total operating costs per Mcfe	$ 6.01	$ 9.33	$ 7.21

Present Activities and Productive Wells

The following table sets forth the wells we have drilled and completed during the periods indicated. All such wells were drilled in the continental United States primarily in federal and state waters in the Gulf of Mexico.

	Years Ended December 31,					
	2009		2008		2007	
	Gross	Net	Gross	Net	Gross	Net
Development:						
Oil	—	—	1	0.15	1	0.25
Gas	—	—	—	—	1	0.12
Non-productive	—	—	1	0.50	—	—
Total	—	—	2	0.65	2	0.37
Exploration:						
Oil	—	—	—	—	—	—
Gas	—	—	—	—	2	0.63
Non-productive	—	—	2	0.22	3	0.47
Total	—	—	2	0.22	5	1.10

At December 31, 2009 we were not involved in the drilling of any wells.

The following table sets forth our productive wells as of December 31, 2009:

	Wells	
	Gross	Net
Oil:		
Working interest	32.00	19.35
Royalty interest	—	—
Total	32.00	19.35
Gas:		
Working interest	19.00	5.89
Royalty interest	5.00	0.13
Total	24.00	6.03

A well is categorized as an oil well or a natural gas well based upon the ratio of oil to gas reserves on a Mcfe basis. However, some of our wells produce both oil and gas. At December 31, 2009, we had no wells with multiple completions.

Leasehold Acreage

The following table shows our approximate developed and undeveloped (gross and net) leasehold acreage as of December 31, 2009.

	Leasehold Acreage			
	Developed		Undeveloped	
Location	Gross	Net	Gross	Net
Louisiana	4,320	1,964	1,522	973
Texas	4,800	3,167	19,059	9,136
Federal waters	53,210	18,387	157,914	99,841
Total	62,330	23,518	178,495	109,950

Major Customers

Our production is sold generally on month-to-month contracts at prevailing prices. The following table identifies customers to whom we sold a significant percentage of our total oil and gas production during each of the 12-month periods ended:

	December 31,		
	2009	2008	2007
Shell Trading Company	45%	33%	25%
Plains Marketing, L.P.	23%	23%	10%
Louis Dreyfus Energy Services	15%	16%	20%
StatoilHydro	—	—	13%

Because alternative purchasers of oil and gas are readily available, we believe that the loss of any of these purchasers would not result in a material adverse effect on our ability to market future oil and gas production.

Title to Properties

We believe that the title to our oil and gas properties is good and defensible in accordance with standards generally accepted in the oil and gas industry, subject to such exceptions which, in our opinion, are not so material as to detract substantially from the use or value of such properties. Our properties are typically subject, in one degree or another, to one or more of the following:

- royalties and other burdens and obligations, express or implied, under oil and gas leases;
- overriding royalties and other burdens created by us or our predecessors in title;
- a variety of contractual obligations (including, in some cases, development obligations) arising under operating agreements, farmout agreements, production sales contracts and other agreements that may affect the properties or their titles;
- back-ins and reversionary interests existing under purchase agreements and leasehold assignments;
- liens that arise in the normal course of operations, such as those for unpaid taxes, statutory liens securing obligations to unpaid suppliers and contractors and contractual liens under operating agreements;
- pooling, unitization and communitization agreements, declarations and orders; and
- easements, restrictions, rights-of-way and other matters that commonly affect property.

To the extent that such burdens and obligations affect our rights to production revenues, they have been taken into account in calculating our net revenue interests and in estimating the size and value of our reserves. We believe that the burdens and obligations affecting our properties are conventional in the industry for properties of the kind owned by us.

Corporate Offices

Our headquarters are located in Natchez, Mississippi, in approximately 51,500 square feet of owned space. We also maintain a leased business office in Houston, Texas, and own or lease field offices in the area of the major fields in which we operate properties or have a significant interest. Replacement of any of our leased offices would not result in material expenditures by us as alternative locations to our leased space are anticipated to be readily available**.**

Employees

We had 72 employees as of December 31, 2009, none of whom are currently represented by a union. We believe that we have good relations with our employees. We employ seven petroleum engineers and four petroleum geoscientists.

Regulations

General. The oil and gas industry is subject to regulation at the federal, state and local level, and some of the laws, rules and regulations that govern our operations carry substantial penalties for non-compliance. This regulatory burden increases our cost of doing business and, consequently, affects our profitability.

Exploration and Production. Our operations are subject to federal, state and local regulations that include requirements for permits to drill and to conduct other operations and for provision of financial assurances (such as bonds and letters of credit) covering drilling and well operations. Other activities subject to regulation are:

- the location and spacing of wells,
- the method of drilling and completing wells,
- the rate and method of production,
- the surface use and restoration of properties upon which wells are drilled and other exploration activities,
- the plugging and abandoning of wells,
- the discharge of contaminants into water and the emission of contaminants into air,
- the disposal of fluids used or other wastes obtained in connection with operations,
- the marketing, transportation and reporting of production, and
- the valuation and payment of royalties.

For instance, our outer continental shelf ("OCS") leases in federal waters are administered by MMS, and require compliance with detailed MMS regulations and orders. Lessees must obtain MMS approval for exploration, exploitation and production plans prior to the commencement of such operations. The MMS has promulgated regulations requiring offshore production facilities located on the OCS to meet stringent engineering and construction specifications. The MMS also has regulations restricting the flaring or venting of natural gas, and prohibiting the flaring of liquid hydrocarbons and oil without prior authorization. MMS policies concerning the volume of production that a lessee must have to maintain an offshore lease beyond its primary term also are applicable to Callon. Similarly, the MMS has promulgated other regulations governing the plugging and abandonment of wells located offshore and the installation and removal of production facilities. To cover the various obligations of lessees on the OCS, the MMS generally requires that lessees post bonds, letters of credit, or other acceptable assurances that such obligations will be met. The cost of these bonds or other surety can be substantial, and there is no assurance that bonds or other surety can be obtained in all cases. Under some circumstances, the MMS may require any of our operations on federal leases to be suspended or terminated. Any such suspension or termination could materially adversely affect our financial conditions and results of operations.

Operations conducted on federal or state oil and natural gas leases must comply with numerous regulatory restrictions, including various nondiscrimination statues, royalty and related valuation requirements, and certain of these operations must be conducted pursuant to certain on-site security regulations and other appropriate permits issued by the MMS or other appropriate federal or state agencies.

Our sales of oil and natural gas are affected by the availability, terms and cost of pipeline transportation. The price and terms for access to pipeline transportation remain subject to extensive federal and state regulation. If these regulations change, we could face higher transmission costs for our production and, possibly, reduced access to transmission capacity.

Various proposals and proceedings that might affect the petroleum industry are pending before Congress, the Federal Energy Regulatory Commission, or FERC, various state legislatures, and the courts. The industry historically has been heavily regulated and we can offer you no assurance that the less stringent regulatory approach recently pursued by the FERC and Congress will continue nor can we predict what effect such proposals or proceedings may have on our operations.

We do not currently anticipate that compliance with existing laws and regulations governing exploration and production will have a significantly adverse effect upon our capital expenditures, earnings or competitive position.

Environmental Regulation. Various federal, state and local laws and regulations concerning the release of contaminants into the environment, including the discharge of contaminants into water and the emission of contaminants into the air, the generation, storage, treatment, transportation and disposal of wastes, and the protection of public health, welfare, and safety, and the environment, including natural resources, affect our exploration, development and production operations, including operations of our processing facilities. We must take into account the cost of complying with environmental regulations in planning, designing, drilling, constructing, operating and abandoning wells. Regulatory requirements relate to, among other things, the handling and disposal of drilling and production waste products, the control of water and air pollution and the removal, investigation, and remediation of petroleum-product contamination. In addition, our operations may require us to obtain permits for, among other things,

- air emissions,
- discharges into surface waters, and
- the construction and operations of underground injection wells or surface pits to dispose of produced saltwater and other nonhazardous oilfield wastes.

In the event of an unauthorized discharge (e.g., to land or water), emission (e.g., to air) or other activity, we may be liable for, among other things, penalties, costs and damages, and subject to injunctive relief, and we could be required to cleanup or mitigate the environmental impacts of those discharges, emissions or activities. Also, under federal, and certain state, laws, the present and certain past owners and operators of a site, and persons that treated, disposed of or arranged for the disposal of hazardous substances found at a site, may be liable, without regard to fault or the legality of the original conduct, for the release of hazardous substances into the environment. The Environmental Protection Agency, state environmental agencies and, in some cases third parties are authorized to take actions in response to threats to human health or the environment and to seek to recover from responsible classes of persons the costs of such actions. We therefore could be required to remove or remediate previously disposed wastes and remediate contamination, including contamination in surface water, soil or groundwater, caused by disposal of that waste, irrespective of whether disposal or release were authorized. We could be responsible for wastes disposed of or released by us or prior owners or operators at properties owned or leased by us or at locations where wastes have been taken for disposal also irrespective of whether disposal or release were authorized. We could also be required to suspend or cease operations in contaminated areas, or to perform remedial well plugging operations or cleanups to prevent future contamination.

Federal, and certain state, laws also impose duties and liabilities on certain “responsible parties” related specifically to the prevention of oil spills and damages resulting from such spills in or threatening United States waters or adjoining shorelines. A liable “responsible party” includes the owner or operator of a facility, vessel or pipeline that is a source of an oil discharge or that poses the substantial threat of discharge or, in the case of offshore facilities, the lessee or permittee of the area in which a discharging facility is located. These laws assign liability, which generally is joint and several, without regard to fault, to each liable party for oil removal costs and a variety of public and private damages. Although defenses and limitations exist to the liability imposed under these laws, they are limited. In the event of an oil discharge or substantial threat of discharge, we could be liable for costs and damages.

The Environmental Protection Agency and various state agencies have limited the disposal options for hazardous and nonhazardous wastes thereby increasing the costs of disposal. Furthermore, certain wastes generated by our oil and natural gas operations that are currently exempt from treatment as hazardous wastes may in the future be designated as hazardous wastes and, therefore, be subject to considerably more rigorous and costly operating and disposal requirements.

Federal and state occupational safety and health laws require us to organize information about hazardous materials used, released or produced in our operations. Certain portions of this information must be provided to employees, state and local governmental authorities and local citizens. We are also subject to the requirements and reporting set forth in federal workplace standards.

There are federal and certain state laws that impose restrictions on activities adversely affecting the habitat of certain plant and animal species. In the event of an unauthorized impact or taking of a protected species or its habitat, we could be liable for penalties, costs and damages, and subject to injunctive relief, and we could be required to mitigate those impacts. A critical habitat or suitable habitat designation also could result in further material restrictions to land use and may materially delay or prohibit land access for oil and natural gas development.

We have made and will continue to make expenditures to comply with environmental regulations and requirements. These are necessary costs of doing business within the oil and gas industry. Although we are not fully insured against all environmental risks, we maintain insurance coverage which we believe is customary in the industry. Moreover, it is possible that other developments, such as stricter and more comprehensive environmental laws and regulations, as well as claims for damages to property or persons resulting from company operations, could result in substantial costs and liabilities. We believe we are in compliance with existing environmental regulations, and that, absent the occurrence of an extraordinary event the effect of which cannot be predicted, any noncompliance will not have a material adverse effect on our operations or earnings.

Greenhouse Gas Legislation (“GHG”). On June 26, 2009, the U.S. House of Representatives passed the “American Clean Energy and Security Act of 2009” which among other things, would enact a “cap and trade” system to control GHGs. Under this cap and trade system, a cap on the amount of GHGs would be established annually, which would be reduced annually. Each covered emission source would be required to obtain GHG emission allowances corresponding to its annual emissions of GHGs. The Senate has passed from committee its legislation proposing a similar cap and trade system to regulate GHG emissions, but the

Senate legislation has not been voted upon by the full Senate. In the absence of a comprehensive federal legislation on GHG emission control, the Environmental Protection Agency ("EPA") has been moving forward with rulemaking under the Clean Air Act ("CAA") to regulate GHGs as pollutants under the CAA. Should EPA regulate GHGs under the CAA, we could incur significant costs to control our emissions and comply with regulatory requirements. In addition, EPA has adopted a mandatory GHG emissions reporting program which imposes reporting and monitoring requirements on various industries. We do not believe our operations will be subject to this program as currently proposed, but there is no guarantee that EPA will not expand the program to include additional industries. Should we be required to report GHG emissions, it could require us to incur costs to monitor, keep records of, and report emissions of GHGs.

Because of the lack of any comprehensive legislative program addressing GHGs, there is a great deal of uncertainty as to how and when federal regulation of GHGs might take place. In addition to possible federal regulation, a number of states, individually and regionally, also are considering or have implemented GHG regulatory programs. These potential regional and state initiatives may result in so—called cap—and—trade programs, under which overall GHG emissions are limited and GHG emissions are then allocated and sold, and possibly other regulatory requirements, that could result in our incurring material expenses to comply, e.g., by being required to purchase or to surrender allowances for GHGs resulting from our operations. The federal, regional and local regulatory initiatives also could adversely affect the marketability of the oil and natural gas we produce. The impact of such future programs cannot be predicted, but we do not expect our operations to be affected any differently than other similarly situated domestic competitors.

Application of the Safe Drinking Water Act to Hydraulic Fracturing. The Safe Drinking Water Act regulates, among other things, underground injection operations. Recent legislative activity has occurred which, if successful, would impose additional regulation under the SDWA upon the use of hydraulic fracturing fluids. The U.S. Senate and House of Representatives are considering two companion bills entitled the "Fracturing Responsibility and Chemical Awareness Act of 2009." If enacted, the legislation would impose on our hydraulic fracturing operations permit and financial assurance requirements, requirements that we adhere to construction specifications, fulfill monitoring, reporting and recordkeeping obligations, and meet plugging and abandonment requirements. In addition to subjecting the injection of hydraulic fracturing to the SDWA regulatory and permitting requirements, the proposed legislation would require the disclosure of the chemicals within the hydraulic fluids, which could make it easier for third parties opposing hydraulic fracturing to initiate legal proceedings based on allegations that specific chemicals used in the process could adversely affect ground water. Neither piece of legislation has been passed. If this or similar legislation is enacted, we could incur substantial compliance costs, and the requirements could negatively impact our ability to conduct fracturing activities on our assets.

SDAs. In addition, eleven states have enacted surface damage statutes ("SDAs"). These laws are designed to compensate for damage caused by mineral development. Most SDAs contain entry notification and negotiation requirements to facilitate contact between operators and surface owners/users. Most laws also contain bonding requirements and specific expenses for exploration and operating activities. Costs and delays associated with SDAs could impair operational effectiveness and increase development costs.

Other Regulations. If we conduct operations on federal, state or Indian oil and natural gas leases, these operations must comply with numerous regulatory restrictions, including various nondiscrimination statutes, royalty and related valuation requirements. Certain of these operations must be conducted pursuant to certain on-site security regulations and other appropriate permits issued by the Bureau of Land Management, Minerals Management Service or other appropriate federal or state agencies.

Commitments and Contingencies

The Company's activities are subject to federal, state and local laws and regulations governing environmental quality and pollution control. Although no assurances can be made, the Company believes that, absent the occurrence of an extraordinary event, compliance with existing federal, state and local laws, rules and regulations governing the release of materials into the environment or otherwise relating to the protection of the environment will not have a material effect upon the capital expenditures, earnings or the competitive position of the Company with respect to its existing assets and operations. The Company cannot predict what effect additional regulation or legislation, enforcement polices thereunder, and claims for damages to property, employees, other persons, and the environment resulting from the Company's operations could have on its activities.

Availability of Reports

All of our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and amendments to such reports as well as other filings we make pursuant to Section 13(a) and 15(d) of the Securities Exchange Act of 1934 are available free of charge on our Internet website. The address of our Internet website is www.callon.com. Our SEC filings are available on our website as soon as they are filed with the SEC.

Item 1A. Risk Factors

Risk Factors

We may be unable to integrate successfully the operations of recent and future acquisitions with our operations, and we may not realize all the anticipated benefits of these acquisition. We intend to focus on producing property acquisitions. Integration of corporate acquisitions with our existing business and operations will be a complex, time consuming and costly process. We can offer no assurance that we will achieve the desired profitability from any acquisitions we may complete in the future. In addition, failure to assimilate recent and future acquisitions successfully could adversely affect our financial condition and results of operations.

Our acquisitions may involve numerous risks, including:

- operating a larger combined organization and adding operations;
- difficulties in the assimilation of the assets and operations of the acquired business, especially if the assets acquired are in a new business segment or geographic area;
- risk that oil and natural gas reserves acquired may not be of the anticipated magnitude or may not be developed as anticipated;
- loss of significant key employees from the acquired business:
- diversion of management's attention from other business concerns;
- failure to realize expected profitability or growth;
- failure to realize expected synergies and cost savings;
- coordinating geographically disparate organizations, systems and facilities; and
- coordinating or consolidating corporate and administrative functions.

Further, unexpected costs and challenges may arise whenever businesses with different operations or management are combined, and we may experience unanticipated delays in realizing the benefits of an acquisition. If we consummate any future acquisition, our capitalization and results of operation may change significantly, and you may not have the opportunity to evaluate the economic, financial and other relevant information that we will consider in evaluating future acquisitions.

We may fail to fully identify problems with any properties we acquire. We acquired a portion of our acreage position in Louisiana and Texas through acquisitions and acreage trades, and we may acquire additional acreage in these areas or other regions in the future. Although we conduct a review of properties we acquire which we believe is consistent with industry practices, we can give no assurance that we have identified or will identify all existing or potential problems associated with such properties or that we will be able to mitigate any problems we do identify.

If the United States experiences a sustained economic downturn or recession, oil and natural gas prices may fall or remain at their current prices for an extended period of time, which may adversely affect our results of operations. The unprecedented disruption in the United States and international credit markets in 2008 resulted in a rapid deterioration in the worldwide economy and tightening of the financial markets. The outlook for the economy in 2010 is uncertain. The current global credit and economic environment has reduced worldwide demand for energy and resulted in significantly lower oil and natural gas prices than in earlier periods. A sustained reduction in the prices we receive for our oil and natural gas production could have a material adverse effect on our results of operations. In addition, any worsening of domestic and global economic conditions could adversely affect our business and results of operations.

We may not be able to obtain funding on acceptable terms or at all. Global financial markets and economic conditions have been disrupted and volatile due to a variety of factors. As a result, the cost of raising money in the debt and equity capital markets and the availability of funds from those markets is unpredictable. Although we have been able to successfully raise money in the current economic climate and refinance certain debt instruments, we may not be successful in the future. In addition, lending counterparties under existing revolving credit facilities and debt instruments may be unwilling or unable to meet their funding obligations.

Due to these factors, we cannot be certain that new debt or equity financing will be available on acceptable terms. If funding is not available when needed, or is available only on unfavorable terms, we may be unable to meet our obligations as they come due. Moreover, without adequate funding, we may be unable to execute our growth strategy, take advantage of other business opportunities or respond to competitive pressures, any of which could have a negative effect on our revenues and results of operations.

Hedging transactions and receivables expose us to counterparty credit risk. Our hedging transactions expose us to risk of financial loss if a counterparty fails to perform under a contract. We use master agreements which allow us, in the event of default, to elect early termination of all contracts with the defaulting counterparty. If we choose to elect early termination, all asset and liability positions with the defaulting counterparty would be net settled at the time of election. We also monitor the creditworthiness of our counterparty on an ongoing basis. However, the current disruptions occurring in the financial markets could lead to sudden changes in a counterparty’s liquidity, which could impair their ability to perform under the terms of the hedging contract. We are unable to predict sudden changes in a counterparty’s creditworthiness or ability to perform. Even if we do accurately predict sudden changes, our ability to negate the risk may be limited depending upon market conditions.

During periods of falling commodity prices, such as in late 2008 and the first half of 2009, our hedge receivable positions increase, which increases our exposure. If the creditworthiness of our counterparty, which is a major financial institution, deteriorates and results in its nonperformance, we could incur a significant loss.

Some of our customers are experiencing, or may experience in the future, severe financial problems that have had or may have a significant impact on their creditworthiness. We cannot provide assurance that one or more of our customers will not default on their obligations to us or that such a default or defaults will not have a material adverse effect on our business, financial position, future results of operations, or future cash flows. Furthermore, the bankruptcy of one or more of our customers, or some other similar proceeding or liquidity constraint, might make it unlikely that we would be able to collect all or a significant portion of amounts owed by the distressed entity or entities. In addition, such events might force such customers to reduce or curtail their future use of our products and services, which could have a material adverse effect on our results of operations and financial condition.

The adoption of derivatives legislation or regulations related to derivative contracts could have an adverse impact on our ability to hedge risks associated with our business. Legislation has been proposed in Congress and by the Treasury Department to impose restrictions on certain transactions involving derivatives, which could affect the use of derivatives in hedging transactions. Under proposed legislation, OTC derivative dealers and other major OTC derivative market participants could be subjected to substantial supervision and regulation. The legislation generally would expand the power of the Commodity Futures Trading Commission, or CFTC, to regulate derivative transactions related to energy commodities, including oil and natural gas, to mandate clearance of derivative contracts through registered derivative clearing organizations, and to impose conservative capital and margin requirements and strong business conduct standards on OTC derivative transactions. The CFTC has proposed regulations that would implement speculative limits on trading and positions in certain commodities. Although it is not possible at this time to predict whether or when Congress may act on derivatives legislation or the CFTC may issue new regulations, any laws or regulations that may be adopted that subject us to additional capital or margin requirements relating to, or to additional restrictions on, our trading and commodity positions could have an adverse effect on our ability to hedge risks associated with our business or on the cost of our hedging activity.

Depressed oil and gas prices may adversely affect our results of operations and financial condition . Our success is highly dependent on prices for oil and gas, which are extremely volatile. Extended periods of low prices for oil or gas will have a material adverse effect on us. Oil and gas markets are both seasonal and cyclical. The prices of oil and gas depend on factors we cannot control such as weather, economic conditions, and levels of production, actions by OPEC and other countries and government actions. Prices of oil and gas will affect the following aspects of our business:

- our revenues, cash flows and earnings;
- the amount of oil and gas that we are economically able to produce;
- our ability to attract capital to finance our operations and the cost of the capital;
- the amount we are allowed to borrow under our senior secured credit facility;
- the value of our oil and gas properties; and
- the profit or loss we incur in exploring for and developing our reserves.

Our reserve information represents estimates that may turn out to be incorrect if the assumptions upon which these estimates are based are inaccurate. Any material inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves. The process of estimating oil and gas reserves is complex. It requires interpretations of available technical data and various assumptions, including assumptions relating to economic factors. Any significant in accuracies in these interpretations or assumptions could materially affect the estimated quantities and present value of reserves shown in this annual report.

In order to prepare these estimates, we must project production rates and the timing of development expenditures. We must also analyze available geological, geophysical, production and engineering data, the extent, completeness, quality and reliability of which can vary. The process also requires us to make economic assumptions, such as oil and gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. Therefore, estimates of oil and gas reserves are inherently imprecise.

Actual future production, oil and gas prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable oil and gas reserves most likely will vary from the estimates. Any significant variance could materially affect the estimated quantities and present value of reserves shown in this report. In addition, estimates of proved reserves may be adjusted to reflect production history, results of exploration and development, prevailing oil and gas prices and other factors, many of which are beyond our control.

In addition, the new reserve reporting requirements effective January 1, 2010, represent a significant change in the types and methods of quantifying reserve, the details of which are still being considered and refined by the SEC. These changes are the first major modifications to the accounting-based reserve reporting requirements since 1982. The new SEC rules replace the previous pricing mechanism of using the last day of the fiscal year by using an average price based on the first day of the last twelve months. In addition, these new requirements permit oil and gas companies to report not just the proved reserves, but also probable and possible reserves. While the new rules attempt to provide users of the financial statements with a more complete picture of the reserves of reporting companies, and recognize new technologies and knowledge about the geology and extent of oil and natural gas fields, these changes will potentially affect the results of our reserve estimates. Application of these new, more subjective, reserve reporting rules by competitors may change our relative positioning in the industry as a whole.

You should not assume that the present value of future net cash flows from our proved reserves referred to in this report is the current market value of our estimated oil and gas reserves. In accordance with SEC requirements, we generally base the estimated discounted future net cash flows from our proved reserves on prices and costs on the date of the estimate. Actual future prices and costs may differ materially from those used in the present value estimate.

The discounted present value of our oil and gas reserves is prepared in accordance with guidelines established by the SEC. A purchaser of reserves would use numerous other factors to value the reserves. The discounted present value of reserves, therefore, does not necessarily represent the fair market value of those reserves.

On December 31, 2009, approximately 18% of the discounted present value of our estimated net proved reserves was PUDs. PUDs represented 34% of total proved reserves. Approximately 71% of the PUDs were attributable to our deepwater properties.

Information about reserves constitutes forward-looking information. See “Forward-Looking Statements” for information regarding forward-looking information.

Unless we are able to replace reserves that we have produced, our cash flows and production will decrease over time. Our future success depends upon our ability to acquire, find and develop oil and gas reserves that are economically recoverable. Without successful exploration or acquisition activities, our reserves, production and revenues will decline. We cannot assure you that we will be able to find and develop or acquire additional reserves at an acceptable cost.

A significant part of the value of our production and reserves is concentrated in a small number of offshore properties, and any production problems or inaccuracies in reserve estimates related to those properties would adversely impact our business. During 2009, approximately 75% of our daily production came from four of our properties in the Gulf of Mexico. Moreover, one property accounted for 38% of our production during this period. In addition, at December 31, 2009, most of our proved reserves were located in two fields in the Gulf of Mexico, with approximately 67% of our total net proved reserves attributable to these properties. If mechanical problems, storms or other events curtailed a substantial portion of this production or if the actual reserves associated with any one of these producing properties are less than our estimated reserves, our results of operations and financial condition could be adversely affected.

Our exploration projects increase the risks inherent in our oil and gas activities. Part of our business strategy is to replace reserves through exploration, where the risks are greater than in acquisitions and development drilling. Although we have been successful in exploration in the past, we cannot assure you that we will continue to increase reserves through exploration or at an acceptable cost. Additionally, we are often uncertain as to the future costs and timing of drilling, completing and producing wells. Our drilling operations may be curtailed, delayed or canceled as a result of a variety of factors, including:

- unexpected drilling conditions;
- overpressured formations and resultant blowouts or cratering;
- equipment failures or accidents;
- adverse weather conditions;
- governmental requirements; and
- shortages or delays in the availability of drilling rigs and the delivery of equipment.

We do not operate all of our properties, and have limited influence over the operations of some of these properties, particularly our two deepwater properties. Our lack of control could result in the following:

- the operator may initiate exploration or development at a faster or slower pace than we prefer;
- the operator may propose to drill more wells or build more facilities on a project than we have funds for or that we deem appropriate, which may mean that we are unable to participate in the project or share in the revenues generated by the project even though we paid our share of exploration costs; and
- if an operator refuses to initiate a project, we may be unable to pursue the project.

Any of these events could materially reduce the value of our non-operated properties.

Competitive industry conditions may negatively affect our ability to conduct operations. We compete with numerous other companies in virtually all facets of our business. Our competitors in development, exploration, acquisitions and production include major integrated oil and gas companies as well as numerous independents, including many that have significantly greater resources. Therefore, competitors may be able to pay more for desirable leases and evaluate, bid for and purchase a greater number of properties or prospects than the financial or personnel resources of the Company permit. We also compete for the materials, equipment and services that are necessary for the exploration, development and operation of our properties. Our ability to increase reserves in the future will be dependent on our ability to select and acquire suitable prospects for future exploration and development. Factors that affect our ability to compete in the marketplace include:

- our access to the capital necessary to drill wells and acquire properties;
- our ability to acquire and analyze seismic, geological and other information relating to a property;
- our ability to retain the personnel necessary to properly evaluate seismic and other information relating to a property;
- our ability to procure materials, equipment and services required to explore, develop and operate our properties; and
- our ability to access pipelines, and the location of facilities used to produce and transport oil and natural gas production.

Our competitors may use superior technology, which we may be unable to afford, or which would require costly investment by us in order to compete. Our industry is subject to rapid and significant advancements in technology, including the introduction of new products and services using new technologies. As our competitors use or develop new technologies, we may be placed at a competitive disadvantage, and competitive pressures may force us to implement new technologies at a substantial cost. In addition, our competitors may have greater financial, technical and personnel resources that allow them to enjoy technological advantages, and may in the future allow them to implement new technologies before we can. We cannot be certain that we will be able to implement technologies on a timely basis or at a cost that is acceptable to us. One or more of the technologies that we currently use or that we may implement in the future may become obsolete, and we may be adversely affected.

Further increasing our exposure to this risk, we may not be able to replace our reserves or generate cash flows if we are unable to raise capital. We will be required to make substantial capital expenditures to acquire proved producing properties, develop our existing reserves, and to discover new oil and gas reserves. Historically, we have financed these expenditures primarily with cash from operations, proceeds from bank borrowings and proceeds from the sale of debt and equity securities. See "Management's Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources" for a discussion of our capital budget. We cannot assure you that we will be able to raise capital in the future. We also make offers to acquire oil and gas properties in the ordinary course of our business. If these offers are accepted, our capital needs may increase substantially.

Further increasing our exposure to this risk, we expect to continue using our senior secured revolving credit facility to borrow funds to supplement our available cash. The amount we may borrow under our senior secured revolving credit facility may not exceed a borrowing base determined by the lenders under such facility based on their projections of our future production, production costs, taxes, commodity prices and any other factors deemed relevant by our lenders. We cannot control the assumptions the lenders use to calculate our borrowing base. The lenders may, without our consent, adjust the borrowing base semiannually or in situations where we purchase or sell assets or issue debt securities. If our borrowings under the senior secured revolving credit facility exceed the borrowing base, the lenders may require that we repay the excess. If this repayment request were to occur, we might have to sell assets or seek financing from other sources, which may either be unavailable or available on terms not economically justifiable. Sales of assets could further reduce the amount of our borrowing base. We cannot assure you that we would be successful in selling assets or arranging substitute financing. If we were not able to repay borrowings under our senior secured revolving credit facility to reduce the outstanding amount to less than the borrowing base, we would be in default under our senior secured credit facility. For a description of our senior secured revolving credit facility and its principal terms and conditions, see "Management's Discussion and Analysis of Financial Condition and Results of Operations —Liquidity and Capital Resources" and Note 7 to our Consolidated Financial Statements.

Our decision to drill a prospect is subject to a number of factors, and we may decide to alter our drilling schedule or not drill at all. A prospect is a property on which we have identified what our geoscientists believe, based on available seismic and geological information, to be indications of hydrocarbons. Our prospects are in various stages of evaluation, ranging from a prospect which is ready to drill to a prospect that will require substantial additional seismic data processing and interpretation. Whether we ultimately drill a prospect may depend on the following factors:

- receipt of additional seismic data or other geophysical data or the reprocessing of existing data;
- material changes in oil or gas prices;
- the costs and availability of drilling rigs;
- the success or failure of wells drilled in similar formations or which would use the same production facilities;
- availability and cost of capital;
- changes in the estimates of the costs to drill or complete wells;
- our ability to attract other industry partners to acquire a portion of the working interest to reduce exposure to costs and drilling risks;
- decisions of our joint working interest owners: and
- changes to governmental regulations.

We will continue to gather data about our prospects, and it is possible that additional information may cause us to alter our drilling schedule or determine that a prospect should not be pursued at all. You should understand that our plans regarding our prospects are subject to change.

Weather, unexpected subsurface conditions, and other unforeseen operating hazards may adversely impact our ability to conduct business. There are many operating hazards in exploring for and producing oil and gas, including:

- our drilling operations may encounter unexpected formations or pressures, which could cause damage to equipment or personal injury;
- we may experience equipment failures which curtail or stop production;
- we could experience blowouts or other damages to the productive formations that may require a well to be re-drilled or other corrective action to be taken;
- hurricanes, storms and other weather conditions could cause damages to our production facilities or wells; and
- because of these or other events, we could experience environmental hazards, including release of oil and gas from spills, gas leaks, and ruptures.

In the event of any of the foregoing, we may be subject to interrupted production or substantial environmental liability due to injury to persons or loss of life, damage to or destruction of property, natural resources and equipment, pollution and other environmental damage, investigation and remediation requirements, and fines and penalties and injunctive relief. Moreover, a substantial portion of our operations are offshore and are subject to a variety of risks peculiar to the marine environment such as capsizing, collisions, hurricanes and other adverse weather conditions, which can result in substantial damage to facilities and interrupt production, as well as more extensive governmental regulation.

We cannot assure you that we will be able to maintain adequate insurance at rates we consider reasonable to cover our possible losses from operating hazards. The occurrence of a significant event not fully insured or indemnified against could materially and adversely affect our financial condition and results of operations.

We may not have production to offset hedges; by hedging, we may not benefit from price increases. Part of our business strategy is to reduce our exposure to the volatility of oil and gas prices by hedging a portion of our production. In a typical hedge transaction, we will have the right to receive from the other parties to the hedge the excess of the fixed price specified in the hedge over a floating price based on a market index, multiplied by the quantity hedged. If the floating price exceeds the fixed price, we are required to pay the other parties this difference multiplied by the quantity hedged. Additionally, we are required to pay the difference between the floating price and the fixed price when the floating price exceeds the fixed price regardless of whether we have sufficient production to cover the quantities specified in the hedge. Significant reductions in production at times when the floating price exceeds the fixed price could require us to make payments under the hedge agreements even though such payments are not offset by sales of production. Hedging will also prevent us from receiving the full advantage of increases in oil or gas prices above the fixed amount specified in the hedge.

We also enter into price “collars” to reduce the risk of changes in oil and gas prices. Under a collar, no payments are due by either party so long as the market price is above a floor set in the collar and below a ceiling. If the price falls below the floor, the counter-party to the collar pays the difference to us and if the price is above the ceiling, we pay the counter-party the difference.

Another type of hedging contract we have entered into is a put contract. Under a put, if the price falls below the set floor price, the counter-party to the contract pays the difference to us. See “Quantitative and Qualitative Disclosures About Market Risks” for a discussion of our hedging practices.

Compliance with environmental and other government regulations could be costly and could negatively impact production. Our operations are subject to numerous laws and regulations governing the operation and maintenance of our facilities and the discharge of materials into the environment or otherwise relating to environmental protection. For a discussion of the material regulations applicable to us, see “Regulations.” These laws and regulations may:

- require that we acquire permits before commencing drilling;
- impose operational, emissions control and other conditions on our activities;
- restrict the substances that can be released into the environment in connection with drilling and production activities;
- limit or prohibit drilling activities on protected areas such as wetlands, wilderness areas or coral reefs; and
- require measures to remediate or mitigate pollution and environmental impacts from current and former operations, such as cleaning up spills or dismantling abandoned production facilities.

Under these laws and regulations, we could be liable for costs of investigation, removal and remediation, damages to and loss of use of natural resources, loss of profits or impairment of earning capacity, property damages, costs of and increased public services, as well as administrative, civil and criminal fines and penalties, and injunctive relief. We could also be affected by more stringent laws and regulations adopted in the future, including any related climate change and greenhouse gases. Under the common law, we could be liable for injuries to people and property. We maintain limited insurance coverage for sudden and accidental environmental damages. We do not believe that insurance coverage for environmental damages that occur over time is available at a reasonable cost. Also, we do not believe that insurance coverage for the full potential liability that could be caused by sudden and accidental environmental damages is available at a reasonable cost. Accordingly, we may be subject to liability or we may be required to cease production from properties in the event of environmental incidents.

Climate Change Legislation or regulations restricting emissions of "greenhouse gasses" could result in increased operating costs and reduced demand for the oil and gas we produce. On December 15, 2009, the U.S. Environmental Protection Agency (*"EPA"*) officially published its findings that emissions of carbon dioxide, methane and other "greenhouse gases" present an endangerment to public health and the environment because emissions of such gases are, according to the EPA, contributing to warming of the earth's atmosphere and other climatic changes. These findings allow the EPA to adopt and implement regulations that would restrict emissions of greenhouse gases under existing provisions of the federal Clean Air Act. Accordingly, the EPA has proposed two sets of regulations that would require a reduction in emissions of greenhouse gases from motor vehicles and could trigger permit review for greenhouse gas emissions from certain stationary sources.

In addition, on October 30, 2009, the EPA published a final rule requiring the reporting of greenhouse gas emissions from specified large greenhouse gas emission sources in the United States beginning in 2011 for emissions occurring in 2010.

Also, on June 26, 2009, the U.S. House of Representatives passed the "American Clean Energy and Security Act of 2009," or "ACESA," which would establish an economy-wide cap-and-trade program to reduce U.S. emissions of greenhouse gases, including carbon dioxide and methane. ACESA would require a 17% reduction in greenhouse gas emissions from 2005 levels by 2020 and just over an 80% reduction of such emissions by 2050. Under this legislation, the EPA would issue a capped and steadily declining number of tradable emissions allowances authorizing emissions of greenhouse gases into the atmosphere. These reductions would be expected to cause the cost of allowances to escalate significantly over time. The net effect of ACESA will be to impose increasing costs on the combustion of carbon-based fuels such as oil, refined petroleum products, and natural gas.

The U.S. Senate has begun work on its own legislation for restricting domestic greenhouse gas emissions, and the Obama Administration has indicated its support for legislation to reduce greenhouse emissions through an emission allowance system. At the state level, more than one-third of the states, either individually or through multi-state regional initiatives, already have begun implementing legal measures to reduce emissions of greenhouse gases. The adoption and implementation of any regulations imposing reporting obligations on, or limiting emissions of greenhouse gases from, our equipment and operations could require us to incur costs to accumulate the required data and/or reduce emissions of greenhouse gases associated with our operations or could adversely affect demand for the oil and natural gas that we produce.

Significant physical effects of climatic change have the potential to damage our facilities, disrupt our production activities and cause us to incur significant costs in preparing for or responding to those effects. In an interpretative guidance on climate change disclosures, the SEC indicates that climate change could have an effect on the severity of weather (including hurricanes and floods), sea levels, the arability of farmland, and water availability and quality. If such effects were to occur, our exploration and production operations have the potential to be adversely affected. Potential adverse effects could include damages to our facilities from powerful winds or rising waters in low-lying areas, disruption of our production activities either because of climate-related damages to our facilities in our costs of operation potentially arising from such climatic effects, less efficient or non-routine operating practices necessitated by climate effects or increased costs for insurance coverages in the aftermath of such effects. Significant physical effects of climate change could also have an indirect affect on our financing and operations by disrupting the transportation or process-related services provided by midstream companies, service companies or suppliers with whom we have a business relationship. We may not be able to recover through insurance some or any of the damages, losses or costs that may result from potential physical effects of climate change.

Federal legislation and state legislative and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays. The U.S. Senate and House of Representatives are currently considering bills entitled, the "Fracturing Responsibility and Awareness of Chemicals Act," or the "FRAC Act," that would amend the federal Safe Drinking Water Act, or the "SDWA," to repeal an exemption from regulation for hydraulic fracturing. If enacted, the FRAC Act would amend the definition of "underground injection" in the SDWA to encompass hydraulic fracturing activities.

Such a provision could require hydraulic fracturing operations to meet permitting and financial assurance requirements, adhere to certain construction specifications, fulfill monitoring, reporting, and recordkeeping obligations, and meet plugging and abandonment requirements. The FRAC Act also proposes to require the reporting and public disclosure of chemicals used in the fracturing process, which could make it easier for third parties opposing the hydraulic fracturing process to initiate legal proceedings based on allegations that specific chemicals used in the fracturing process could adversely affect groundwater. The adoption of any future federal or state laws or implementing regulations imposing reporting obligations on, or otherwise limiting, the hydraulic fracturing process could make it more difficult to complete natural gas wells and increase our costs of compliance and doing business.

Factors beyond our control affect our ability to market production and our financial results. The ability to market oil and gas from our wells depends upon numerous factors beyond our control. These factors include:

- the extent of domestic production and imports of oil and gas;
- the proximity of the gas production to gas pipelines;
- the availability of pipeline capacity;
- the demand for oil and gas by utilities and other end users;
- the availability of alternative fuel sources;
- the effects of inclement weather;
- state and federal regulation of oil and gas marketing; and
- federal regulation of gas sold or transported in interstate commerce.

Because of these factors, we may be unable to market all of the oil or gas we produce. In addition, we may be unable to obtain favorable prices for the oil and gas we produce.

If oil and gas prices decrease or remain depressed for extended periods of time, we may be required to take additional writedowns of the carrying value of our oil and gas properties. We may be required to writedown the carrying value of our oil and gas properties when oil and gas prices are low or if we have substantial downward adjustments to our estimated net proved reserves, increases in our estimates of development costs or if we experience deterioration in our exploration results. Under the full-cost method, which we use to account for our oil and gas properties, the net capitalized costs of our oil and gas properties may not exceed the present value, discounted at 10%, of future net cash flows from estimated net proved reserves, using period end oil and gas prices or prices as of the date of our auditor's report, plus the lower of cost or fair market value of our unproved properties. If net capitalized costs of our oil and gas properties exceed this limit, we must charge the amount of the excess to earnings. This type of charge will not affect our cash flows, but will reduce the book value of our stockholders' equity. We review the carrying value of our properties quarterly, based on prices in effect as of the end of each quarter or at the time of reporting our results. Once incurred, a writedown of oil and gas properties is not reversible at a later date, even if prices increase. See Note 15 to our Consolidated Financial Statements.

There are inherent limitations in all control systems, and misstatements due to error or fraud that could seriously harm our business may occur and not be detected. Our management, including our Chief Executive Officer and Chief Financial Officer, do not expect that our internal controls and disclosure controls will prevent all possible error and all fraud. A control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. In addition, the design of a control system must reflect the fact that there are resource constraints and the benefit of controls must be relative to their costs. Because of the inherent limitations in all control systems, an evaluation of controls can only provide reasonable assurance that all material control issues and instances of fraud, if any, in our company have been detected. These inherent limitations include the realities that judgments in decision-making can be faulty and that breakdowns can occur because of simple error or mistake. Further, controls can be circumvented by the individual acts of some persons or by collusion of two or more persons. The design of any system of controls is based in part upon certain assumptions about the likelihood of future events, and there can be no assurance that any design will succeed in achieving its stated goals under all potential future conditions. Because of inherent limitations in a cost-effective control system, misstatements due to error or fraud may occur and not be detected. A failure of our controls and procedures to detect error or fraud could seriously harm our business and results of operations.

Forward-Looking Statements

In this report, we have made many forward-looking statements. We cannot assure you that the plans, intentions or expectations upon which our forward-looking statements are based will occur. Our forward-looking statements are subject to risks, uncertainties and assumptions, including those discussed elsewhere in this report. Forward-looking statements include statements regarding:

- our oil and gas reserve quantities, and the discounted present value of these reserves;
- the amount and nature of our capital expenditures;
- drilling of wells;
- the timing and amount of future production and operating costs;
- business strategies and plans of management; and
- prospect development and property acquisitions.

Some of the risks, which could affect our future results and could cause results to differ materially from those expressed in our forward-looking statements, include:

- the current global economic downturn;
- general economic conditions or including the availability of credit and access to existing lines of credit
- the volatility of oil and natural gas prices;
- the uncertainty of estimates of oil and natural gas reserves;
- the impact of competition;
- the availability and cost of seismic, drilling and other equipment;
- operating hazards inherent in the exploration for and production of oil and natural gas;
- difficulties encountered during the exploration for and production of oil and natural gas;
- difficulties encountered in delivering oil and natural gas to commercial markets;
- changes in customer demand and producers’ supply;
- the uncertainty of our ability to attract capital and obtain financing on favorable terms;
- compliance with, or the effect of changes in, the extensive governmental regulations regarding the oil and natural gas business including those related to climate change and greenhouse gases;
- actions of operators of our oil and gas properties; and
- weather conditions.

The information contained in this report, including the information set forth under the heading "Risk Factors," identifies additional factors that could affect our operating results and performance. We urge you to carefully consider these factors and the other cautionary statements in this report. Our forward-looking statements speak only as of the date made, and we have no obligation to update these forward-looking statements.

ITEM 1B. Unresolved Staff Comments

None.

ITEM 3. LEGAL PROCEEDINGS

We are a defendant in various legal proceedings and claims, which arise in the ordinary course of our business. We do not believe the ultimate resolution of any such actions will have a material affect on our financial position or results of operations.

ITEM 4. RESERVED

PART II.

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Our common stock trades on the New York Stock Exchange under the symbol "CPE". The following table sets forth the high and low sale prices per share as reported for the periods indicated.

Quarter Ended	High	Low
2008:		
First quarter	$19.22	$13.42
Second quarter	28.93	17.63
Third quarter	28.00	16.18
Fourth quarter	18.06	1.02
2009:		
First quarter	$ 3.37	$ 0.94
Second quarter	2.93	1.07
Third quarter	2.33	1.42
Fourth quarter	2.12	1.42

As of March 8, 2010 there were approximately 3,556 common stockholders of record.

We have never paid dividends on our common stock and intend to retain our cash flow from operations for the future operation and development of our business. In addition, our primary credit facility and the terms of our outstanding debt prohibit the payment of cash dividends on our common stock.

During the fourth quarter of 2009, neither we nor any affiliated purchasers made repurchases of our equity securities.

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Equity Compensation Plan Information. The following table summarizes information regarding the number of shares of our common stock that are available for issuance under all of our existing equity compensation plans as of December 31, 2009.

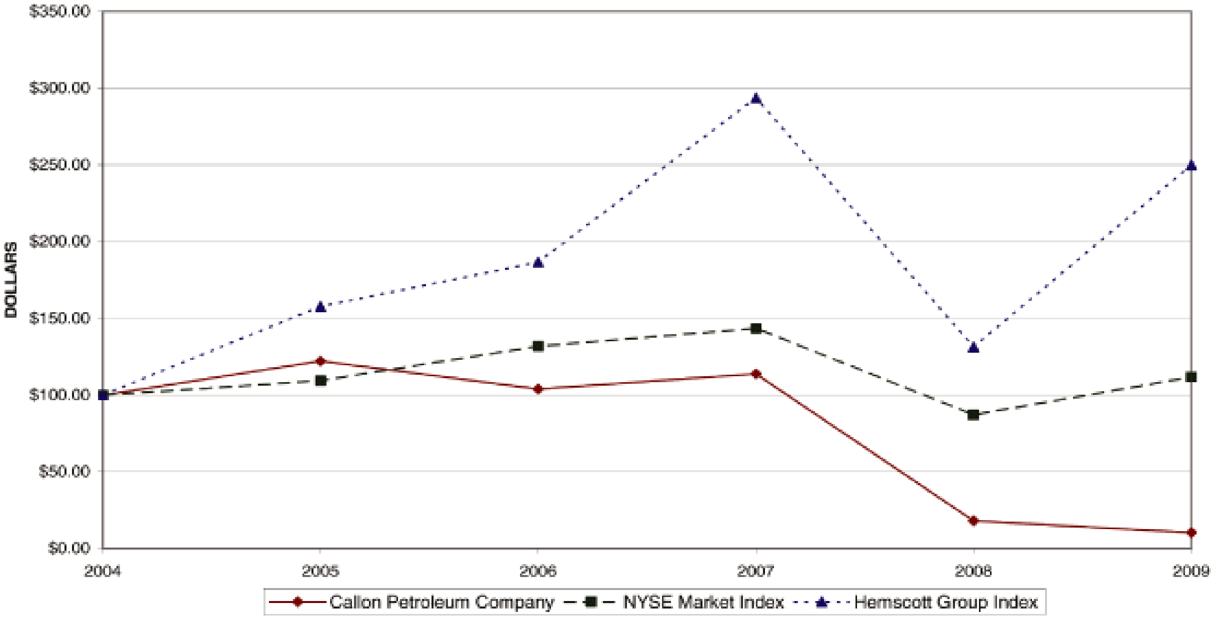
Plan Category	Number of securities to be issued upon exercise of outstanding options	Weighted-average exercise price of outstanding options, warrants and rights	Number of securities remaining available for future issuance under equity
Equity compensation plans approved by security holders	402,875	$ 10.85	1,252,921
Equity compensation for inducement of employment	500,000	2.76	
Equity compensation plans not approved by security holders	75,483	6.40	37,466
Total	978,358	$ 6.37	1,290,387

See Notes 4 and 16 to our Consolidated Financial Statements.

Performance Graph

The following graph compares the yearly percentage change for the five years ended December 31, 2009, in the cumulative total shareholder return on the Company's Common Stock against the cumulative total return for the (i) Hemscott Industry and Market Index of SIC Group 123 (the "Hemscott Group Index") consisting of independent oil and gas drilling and exploration companies and (ii) the New York Stock Exchange Market Index. The comparison of total return on an investment for each of the periods assumes that $100 was invested on December 31, 2004 in the Company, the Hemscott Group Index and the New York Stock Exchange Market Index, and that all dividends were reinvested.

COMPARISON OF 5-YEAR CUMULATIVE TOTAL RETURN AMONG CALLON PETROLEUM COMPANY, NYSE MARKET INDEX AND HEMSCOTT GROUP INDEX



ASSUMES $100 INVESTED ON JAN. 01, 2005
ASSUMES DIVIDEND REINVESTED
FISCAL YEAR ENDING DEC. 31, 2009

Company/Index/Market	2004	2005	2006	2007	2008	2009
Callon Petroleum Company	$100.00	$122.06	$103.94	$113.76	$ 17.98	$ 10.37
NYSE Market Index	$100.00	$109.36	$131.75	$143.43	$ 87.12	$111.76
Hemscott Group Index	$100.00	$157.64	$186.69	$293.61	$131.45	$249.89

ITEM 6. SELECTED FINANCIAL DATA

The following table sets forth, as of the dates and for the periods indicated, selected financial information about us. The financial information for each of the five years in the period ended December 31, 2009 has been derived from our audited Consolidated Financial Statements for such periods. The information should be read in conjunction with “Management’s Discussion and Analysis of Financial Condition and Results of Operations” and the Consolidated Financial Statements and Notes thereto. The following information is not necessarily indicative of our future results.

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CALLON PETROLEUM COMPANY
SELECTED HISTORICAL FINANCIAL INFORMATION
(In thousands, except per share amounts)

	Years Ended December 31,				
	2009	2008	2007	2006	2005
Statement of Operations Data:					
Operating revenues:					
Oil and gas sales	$101,259	$ 141,312	$170,768	$182,268	$141,290
Medusa MMS royalty recoupment	40,886	—	—	—	—
Oil and gas sales	142,145	141,312	170,768	182,268	141,290
Operating expenses:					
Lease operating expenses	18,447	19,208	27,795	28,881	24,377
Depreciation, depletion and amortization	33,443	64,054	72,762	65,283	44,946
General and administrative	13,355	9,565	9,876	8,591	8,085
Accretion expense	3,149	4,172	3,985	4,960	3,549
Acquisition expense	298	—	—	—	—
Derivative expense	—	498	—	150	6,028
Impairment of oil and gas properties	—	485,498	—	—	—
Total operating expenses	68,692	582,995	114,418	107,865	86,985
Income (loss) from operations	73,453	(441,683)	56,350	74,403	54,305
Other (income) expenses:					
Interest expense	19,089	23,986	34,329	16,480	16,660
Callon Entrada (non-recourse) interest expense	7,072	2,719	—	—	—
9.75% Senior Note restructuring expense	1,024	—	—	—	—
Interest on MMS royalty recoupment	(7,681)	—	—	—	—
Other (income) expense	190	(1,379)	(1,172)	(1,869)	(998)
Loss on early extinguishment of debt	—	11,871	—	—	—
Total other (income) expenses	19,694	37,197	33,157	14,611	15,662
Income (loss) before income taxes	53,759	(478,880)	23,193	59,792	38,643
Income tax expense (benefit)	—	(39,725)	8,506	20,707	13,209
Income (loss) before equity in earnings of Medusa Spar LLC	53,759	(439,155)	14,687	39,085	25,434
Equity in earnings of Medusa Spar LLC, net of tax	660	262	507	1,475	1,342
Net income (loss)	54,419	(438,893)	15,194	40,560	26,776
Preferred stock dividends	—	—	—	—	318
Net income (loss) available to common shares	$ 54,419	$(438,893)	$ 15,194	$ 40,560	$ 26,458
Net income (loss) per common share:					
Basic	$ 2.47	$ (20.68)	$ 0.73	$ 2.00	$ 1.43
Diluted	$ 2.45	$ (20.68)	$ 0.71	$ 1.90	$ 1.28
Shares used in computing net income (loss) per common share:					
Basic	22,072	21,222	20,776	20,270	18,453
Diluted	22,200	21,222	21,290	21,363	20,883

CALLON PETROLEUM COMPANY
SELECTED HISTORICAL FINANCIAL INFORMATION
(In thousands, except per share amounts)

	Years Ended December 31,				
	2009	2008	2007	2006	2005
Balance Sheet Data (end of period):					
Oil and gas properties, net	$130,608	$ 159,252	$681,706	$547,027	$447,364
Total assets	$227,991	$ 266,090	$792,482	$625,527	$533,776
Long-term debt, less current portion	$179,174	$ 272,855	$392,012	$225,521	$188,813
Stockholders' equity (deficit)	$ (80,854)	$(129,804)	$287,075	$281,363	$228,048

We follow the full-cost method of accounting for oil and gas properties. Under this method of accounting, our net capitalized costs to acquire, explore and develop oil and gas properties may not exceed the sum of (1) the estimated future net revenues from proved reserves at current prices discounted at 10% and (2) the lower of cost or market of unevaluated properties, net of tax (the full-cost ceiling amount). If these capitalized costs exceed the full-cost ceiling amount, the excess is charged to expense. For the year ended December 31, 2008, the Company recorded a $485.5 million impairment of oil and gas properties as a result of the ceiling test. See Note 15 to the Consolidated Financial Statements.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following discussion is intended to assist in an understanding of our financial condition and results of operations. Our consolidated financial statements and notes thereto contain detailed information that should be referred to in conjunction with the following discussion. See Item 8 "Financial Statements and Supplementary Data."

We have been engaged in the exploration, development, acquisition and production of oil and gas properties since 1950. Prior to 2009, our operations were focused on exploration and production in the Gulf of Mexico. Following the abandonment of our Entrada project in 2008, we took steps to change our operational focus to lower risk, onshore exploration and development activities. During 2009, we took the following actions:

- We exchanged a new series of senior notes due 2016 and common stock for a substantial portion of our existing $200 million of senior notes due 2010, and reduced principal from $200 million to $154 million.
- We filed for recoupment of deepwater royalty payments, and received a payment from the MMS of $44.8 million in January 2010. We expect to receive an additional payment from the MMS of approximately $7.7 million during 2010, representing interest.
- We began negotiating a new $100 million revolving credit facility, with a borrowing base of $20 million, which we finalized in January 2010.

These activities were undertaken to allow us to shift our operational focus from the offshore Gulf of Mexico to longer life, lower risk onshore properties. As part of this strategy, we employed Steven B. Hinchman as our Chief Operating Officer. Mr. Hinchman has substantial experience in onshore oil and gas acquisition, exploration and development activities. During 2009, we closed two acquisitions as part of this new focus:

- In September 2009, we acquired a 70% working interest in a 577-acre unit in the heart of the Haynesville Shale play in Bossier Parish, Louisiana for $3.0 million. We plan to drill a total of seven horizontal wells on this property, with the first two wells to be drilled in 2010. We will be operator of these wells.
- On October 28, 2009, we acquired interests in properties producing from the Wolfberry formation in Crockett, Ector, Midland and Upton Counties, Texas for total cash consideration of $16.0. The acquisition included year-end proven reserves of 1.6 MMBoe, 22 existing wells producing 350 Boe per day and upside from a multi-year inventory of drilling opportunities. We will operate substantially all of the production and development of these properties.

Deconsolidation of Callon Entrada Company

In June 2009, the FASB issued an accounting standard which amends US GAAP as follows: a) to require an enterprise to perform an analysis to determine whether the enterprise's variable interest or interests give it a controlling financial interest in a variable interest entity ("VIE"), identifying the primary beneficiary of a VIE, b) to require ongoing reassessment of whether an enterprise is the primary beneficiary of a VIE, rather than only when specific events occur, c) to eliminate the quantitative approach previously required for determining the primary beneficiary of a VIE, d) to amend certain guidance for determining whether an entity is a VIE, e) to add an additional reconsideration event when changes in facts and circumstances pertinent to a VIE occur, f) to eliminate the exception for troubled debt restructuring regarding VIE reconsideration, and g) to require advanced disclosures that will provide users of financial statement with more transparent information about an enterprise's involvement in a VIE. This pronouncement is effective for the first annual reporting period that begins after November 15, 2009, with earlier adoption prohibited. We adopted this pronouncement on January 1, 2010. Upon adoption, we reevaluated our interest in our subsidiary, Callon Entrada Company ("Callon Entrada") as a result of the amendments described above.

Based on the evaluation performed applying the new standard, management has concluded that a VIE reconsideration event had taken place resulting in the determination that Callon Entrada is a VIE, for which we are not the primary beneficiary. Therefore, effective January 1, 2010, Callon Entrada will be deconsolidated from our consolidated financial statements. Deconsolidation will result in the removal of approximately $1.8 million of current assets, $2.0 million of current liabilities, $30 million of deferred tax assets, $30 million of valuation allowance and approximately $84.8 million of non-recourse debt and related obligation for the cumulative amount of interest. Retained earnings will be increased by $85.1 million as a cumulative effect of change related to this accounting standard. No gain will be reflected in the statement of operations. See Note 2 to our Consolidated Financial Statements.

2010 OUTLOOK

In 2009, we set our course and began to re-shape our portfolio. We recognized that continuing to solely focus on the Gulf of Mexico shelf and deep water could not sustain profitable growth at an acceptable level of risk. We needed to initiate a transition of resources from offshore to a more diverse and lower risk resource base located both onshore and offshore. We focused our attention on the Permian Basin for oil and the shale gas plays.

In the Permian Basin we plan to drill and complete 16 wells in 2010. These wells are expected to more than double our current Permian Basin production of 350 Boe per day by the end of the year.

In the Haynesville Shale gas play, we plan to drill two wells in 2010. We expect to spud the first well by mid-year and have both wells completed and producing in the fourth quarter of 2010.

We are estimating full year production from our current properties of between 27 and 31 million cubic feet of natural gas equivalent (“MMcfe”) per day, with an exit rate of approximately 35 MMcfe per day. Additionally, any acquisition in 2010 would positively contribute to these estimates.

Our lease operating expense, including severance tax, is expected to range between $18 million and $22 million in 2010 with abandonment costs estimated to be $4 million.

Our new onshore properties along with the strong cash flow from our Gulf of Mexico operations have already begun to re-shape our portfolio and outlook. We are well positioned to continue the pursuit of diversifying our portfolio by building profitable growth opportunities onshore.

Factors potentially impacting our expected production profile include:

- a reduced level of capital expenditures, as discussed below;
- allocation of capital expenditures to acquire producing properties;
- natural field decline in the deepwater Gulf of Mexico and Gulf Coast areas of our US operations;
- timing of well completions in the Permian Basin and Haynesville Shale development programs;
- potential hurricane-related downtime and volume curtailments in the Gulf of Mexico and Gulf Coast areas; and
- inflation of capital costs and operating expenses.

2010 Budget—We have designed a flexible capital spending program that can be funded from cash on hand and cashflows from operations. Our preliminary base capital program includes the development of our Permian Basin assets as well as exploiting our Haynesville Shale play. Including plugging and abandonment, capitalized interest and general and administrative costs our 2010 capital budget is $61.7 million. We do have a $20 million available borrowing base that could be used for an attractive strategic opportunity. However, depending on commodity prices and other economic conditions we experience in 2010, this base capital program may be adjusted up or down.

Inflation has not had a material impact on us, nor is it expected to have a material impact on us in the immediate future.

Summary of Significant Accounting Policies

Property and Equipment. We follow the full-cost method of accounting for oil and gas properties whereby all costs incurred in connection with the acquisition, exploration and development of oil and gas reserves, including certain overhead costs, are capitalized into the “full-cost pool.” The amounts we capitalize into the full-cost pool are depleted (charged against earnings) using the unit-of-production method. The full-cost method of accounting for our proved oil and gas properties requires that we make estimates based on assumptions as to future events that could change. These estimates are described below.

Depreciation, Depletion and Amortization (DD&A) of Oil and Gas Properties. We calculate depletion by using the net capitalized costs in our full-cost pool plus estimated future development costs (combined, the depletable base) and our estimated net proved reserve quantities. Capitalized costs added to the full-cost pool include the following:

- cost of drilling and equipping productive wells, dry hole costs, acquisition costs of properties with proved reserves, delay rentals and other costs related to exploration and development of our oil and gas properties;
- payroll costs including the related to fringe benefits paid to employees directly engaged in the acquisition, exploration and/or development of oil and gas properties as well as other directly identifiable general and administrative costs associated with such activities. Such capitalized costs do not include any costs related to our production of oil and gas or our general corporate overhead;
- costs associated with properties that do not have proved reserves classified as unevaluated property costs and are excluded from the depletable base. These unevaluated property costs are added to the depletable base at such time as wells are completed on the properties, the properties are sold or we determine these costs have been impaired. Our determination that a property has or has not been impaired (which is discussed below) requires that we make assumptions about future events;
- estimated costs to dismantle, abandon and restore properties that are capitalized to the full-cost pool when the related liabilities are incurred under guidance for accounting of asset retirement obligations; and
- estimated future costs to develop proved properties are added to the full-cost pool for purposes of the DD&A computation. We use assumptions based on the latest geologic, engineering, regulatory and cost data available to us to estimate these amounts. However, the estimates we make are subjective and may change over time. Our estimates of future development costs are periodically updated as additional information becomes available.

Capitalized costs included in the full-cost pool plus estimated future development costs are depleted and charged against earnings using the unit-of-production method. Under this method, we estimate the proved reserves quantities at the beginning of each accounting period. For each Mcfe produced during the period, we record a depletion charge equal to the amount included in the depletable base (net of accumulated depreciation, depletion and amortization) divided by our estimated net proved reserve quantities.

Because we use estimates and assumptions to calculate proved reserves (as discussed below) and the amounts included in the depletable base, our depletion rates may materially change if actual results differ from these estimates.

Ceiling Test. Under the full-cost accounting rules of the SEC, we review the carrying value of our proved oil and gas properties each quarter. Under these rules, capitalized costs of oil and gas properties, net of accumulated depreciation, depletion and amortization and deferred income taxes, may not exceed the present value of estimated future net cash flows from proved oil and gas reserves, discounted at 10%, plus the lower of cost or fair value of unevaluated properties, net of related tax effects (the full-cost ceiling amount). These rules generally require pricing future oil and gas production at the unescalated market price for oil and gas at the end of each fiscal quarter, and require a write-down if the "ceiling" is exceeded. However, if prices recover sufficiently subsequent to the balance sheet date before the release of the financial statements, the use of the subsequent pricing is allowed and no write-down would be required. Given the volatility of oil and gas prices, it is reasonably possible that our estimate of discounted future net cash flows from proved oil and gas reserves could change in the near term. If oil and gas prices decline significantly, even if only for a short period of time, it is possible that write-downs of oil and gas properties could occur in the future. See Note 15 to our Consolidated Financial Statements.

Estimating Reserves and Present Value of Estimated Future Net Cash Flows. The estimates of quantities of proved oil and gas reserves including the discounted present value of estimated future net cash flows from such reserves at the end of each quarter are based on numerous assumptions, which are likely to change over time. These assumptions include:

- the prices at which we can sell our oil and gas production in the future. Oil and gas prices are volatile, but we are required to assume that they remain constant. In general, higher oil and gas prices will increase quantities of proved reserves and the present value of estimated future net cash flows from such reserves, while lower prices will decrease these amounts. Because some of our properties have relatively short productive lives, changes in prices will affect the present value of estimated future net cash flows more than the estimated quantities of oil and gas reserves; and
- the costs to develop and produce our reserves and the costs to dismantle our production facilities when reserves are depleted. These costs are likely to change over time, but we are required to assume that costs in effect at the end of the quarter will not change. Increases in costs will reduce estimated oil and gas quantities and the present value of estimated future net cash flows, while decreases in costs will increase such amounts. Because some of our properties have relatively short productive lives, changes in costs will affect the present value of estimated future net cash flows more than the estimated quantities of oil and gas reserves.

In addition, the process of estimating proved oil and gas reserves requires that our independent and internal reserve engineers exercise judgment based on available geological, geophysical and technical information. We have described the risks associated with reserve estimation and the volatility of oil and gas prices under "Risk Factors."

Sales of oil and gas properties are accounted for as adjustments to the net full cost pool with no gain or loss recognized unless the adjustment would significantly alter the relationship between capitalized costs and proved reserves.

In December 2008 the SEC approved amendments to its oil and gas reserves estimation and disclosure requirements. The amendments, among other things:

- allow the use of reliable technologies to estimate proved reserves if those technologies have been demonstrated to result in reliable conclusions about reserve volumes;
- require disclosure of oil and gas proved reserves by significant geographic area;
- permit the optional disclosure of probable and possible reserves;
- modify the prices used to estimate reserves for SEC disclosure purposes to a 12-month average beginning-of-the-month price instead of a period-end price; and

- require that if a third party is primarily responsible for preparing or auditing the reserve estimates, the company make disclosures relating to the independence and qualifications of the third party, including filing as an exhibit any report received from the third party.

The new requirements are effective for our year-end financial statements and our Annual Report on Form 10-K for the year ended December 31, 2009. We have adopted the new requirements, which had no material impact on our financial statements.

Unproved Properties. Costs associated with properties that do not have proved reserves, including capitalized interest, are excluded from the depletable base. These unproved properties are included in the line item "Unevaluated properties excluded from amortization." Unproved property costs are transferred to the depletable base when wells are completed on the properties or the properties are sold. In addition, we are required to determine whether our unproved properties are impaired and, if so, include the costs of such properties in the depletable base. We determine whether an unproved property should be impaired by periodically reviewing our exploration program on a property by property basis. This determination may require the exercise of substantial judgment by our management.

Asset Retirement Obligations. We are required to record our estimate of the fair value of liabilities for obligations associated with the retirement of tangible long-life assets and the associated asset retirement costs. Interest is accreted on the present value of the asset retirement obligation and reported as accretion expense within operating expenses in the Consolidated Statements of Operations. See Note 11 to our Consolidated Financial Statements.

Derivatives. We periodically use derivative financial instruments to manage oil and gas price risk on a limited amount of our future production and do not use these instruments for trading purposes. Settlement of derivative contracts are generally based on the difference between the contract price or prices specified in the derivative instrument and a NYMEX price or other cash or futures index price.

Our derivative contracts, which are accounted for as cash flow hedges, are recorded at fair market value with changes in fair value recorded through other comprehensive income (loss), net of tax, in stockholders' equity. The cash settlements on these contracts are recorded as an increase or decrease in oil and gas sales. The changes in fair value related to ineffective derivative contracts are recognized as derivative expense (income). The cash settlement on these contracts is also recorded within derivative expense (income). See Note 8 to our Consolidated Financial Statements.

Our derivative contracts are carried at fair value on our consolidated balance sheet under the caption "Fair Market Value of Derivatives". The oil and gas derivative contracts are settled based upon reported prices on NYMEX. The estimated fair value of these contracts is based upon closing exchange prices on NYMEX and in the case of collars and floors, the time value of options. See Note 9, "Fair Value Measurements" to our Consolidated Financial Statements.

In March 2008, the FASB issued guidance for disclosures about derivative instruments and hedging activities. Under the guidance changes the disclosure requirements for derivative instruments and hedging activities, entities are required to provide enhanced disclosures about (a) how and why an entity uses derivative instruments, (b) how derivative instruments and related hedged items are accounted for under GAAP, and (c) how derivative instruments and related hedged items affect an entity's financial position, financial performance, and cash flows. We adopted the guidance on January 1, 2009 and have added certain additional disclosures to our financial statements.

Fair Value Measurements. We adopted guidance issued by the FASB for fair value measurements which defines fair value, establishes a framework for measuring fair value and requires enhanced disclosures about fair value measurements. We also adopted guidance issued by the FASB for the fair value option for financial assets and liabilities, which permits entities to choose to measure various financial instruments and certain other items at fair value. See Note 9 to our Consolidated Financial Statements.

Income Taxes. Provisions for income taxes include deferred taxes resulting primarily from temporary differences due to different reporting methods for oil and gas properties for financial reporting purposes and income tax purposes. GAAP provides for the recognition of a deferred tax asset for net operating loss carryforwards, statutory depletion carryforward and tax credit carryforwards, net of a valuation allowance. The valuation allowance is provided for that portion of the asset for which it is deemed more likely than not will not be realized.

Share-Based Compensation. We account for share-based compensation under guidance issued by the FASB. In June 2008, FASB issued guidance determining whether instruments granted in share-based compensation transactions are participating securities. The guidance addresses whether instruments granted in share-based compensation transactions are participating securities prior to vesting and, therefore, need to be included in the earnings allocation in computing earnings per share under the two-class method described in the FASB issued guidance for earning per share." We adopted this guidance on January 1, 2009 with no impact to its financial statements.

Business Combinations. In December 2007, the FASB issued an accounting standard to improve the relevance, representational faithfulness, and comparability of the information that a reporting entity provides in its financial reports about a business combination and its effects. To accomplish that, the standard establishes principles and requirements for how the acquirer (a) recognizes and measures in its financial statements the identifiable assets acquired, the liabilities assumed, and any noncontrolling interest in the acquiree, (b) recognizes and measures the goodwill acquired in the business combination or a gain from a bargain purchase, and (c) determines what information to disclose to enable users of the financial statements to evaluate the nature and financial effects of the business combination. The business combination guidance is effective for business combinations with an acquisition date on or after the beginning of annual reporting period beginning on or after December 15, 2008. The standard requires an acquirer to recognize 100% of the fair values of acquired assets, with limited exceptions, even if the acquirer has not acquired 100% of its target. Additionally contingent consideration arrangements and preacquisition contingencies will be measured at fair value on the acquisition date and included in the basis of the purchase price. Transaction costs are expensed as incurred and not considered as part of the fair value of the acquisition; however, acquired research and development are no longer expensed at acquisition, but instead are capitalized as an indefinite-lived intangible asset. We adopted this accounting standard on January 1, 2009, and was applied to our ExL acquisition during 2009. See Note 13 for the impact of the acquisition on our Consolidated Financial Statements.

Subsequent Events. In May 2009, the FASB issued guidance for subsequent events. The objective of this guidance is to establish general standards of accounting for and disclosures of events that occur after the balance sheet date but before financial statements are issued or are available to be issued. We adopted the guidance as of the quarter ended June 30, 2009 with limited impact to its financial statements. See Note 20 to our consolidated financial statements.

Recent Accounting Standards

See Note 2 to our Consolidated Financial Statements.

Liquidity and Capital Resources

Historically, our primary sources of capital have been cash flows from operations, borrowings from financial institutions and the sale of debt and equity securities. Net cash and cash equivalents decreased by $13.5 million during 2009 to $3.6 million. Cash provided from operating activities during 2009 totaled $26.4 million, a decrease of 72% from $93.2 million in 2008. The decrease in liquidity is attributable to the reduction of accounts payable related to the Entrada project and lower commodity prices.

During 2009, we recorded a receivable attributable to a recoupment of royalty overpayments we previously made on our deep water properties. Following the decisions in several court cases, it was determined that the MMS was not entitled to receive these royalty payments, and accordingly refunded the payments previously made. We received the principal payment of $44.8 million in January 2010, and expect to receive a payment of approximately $7.7 million representing interest on the amounts previously withheld during 2010. See Note 12 to our Consolidated Financial Statements.

On September 25, 2008, we closed on a four-year second amended and restated senior secured revolving credit facility with Union Bank N.A. as administrative agent and issuing lender. The borrowing base was $16.2 million at December 31, 2009. There was $10 million outstanding under the credit facility at December 31, 2009.

Subsequent to December 31, 2009, our senior secured credit agreement was amended to include Regions Bank as the sole arranger and administrative agent. The third amended and restated senior secured credit agreement, which matures on September 25, 2012, provides for a $100 million facility with an initial borrowing base of $20 million, which will be reviewed and re-determined on a semi-annual basis. The third amended and restated credit facility bears interest at 4% above a defined base rate and in no event will the interest rate be less than 6%. In addition, a commitment fee of 0.5% per annum on the unused portion of the borrowing base, is payable quarterly. Subsequent to December 31, 2009, simultaneously with the execution of the third amended and restated senior secured credit agreement, the Company repaid the $10 million outstanding on the borrowing base under the second amended and restated senior secured credit agreement. See Notes 7 and 20 to our Consolidated Financial Statements.

During the fourth quarter of 2009, we completed an exchange offer for our outstanding 9.75% Senior Notes due December 2010 (“Senior Notes”). For each $1,000 principal amount of outstanding Senior Notes tendered in accordance with the terms and conditions of the exchange offer, each tendering holder of the Senior Notes received $750 principal amount of 13% Senior Secured Notes due 2016 (“Exchange Notes), 20.625 shares of common stock and 1.6875 shares of Convertible Preferred Stock. Holders of approximately 92% of the Senior Notes tendered their notes in the exchange offer. On December 31, 2009, each share of the Convertible Preferred Stock was automatically converted by us into 10 shares of common stock following shareholder approval of the conversion and the filing of an amendment to our charter increasing the number of authorized shares of common stock as necessary to accommodate such conversion. We issued 6.9 million shares of common stock related to the conversion of the Convertible Preferred Stock. In connection with the exchange offer, holders who tendered Senior Notes consented to amend the indenture governing the Senior Notes, eliminating substantially all of the indenture’s restrictive covenants. The outstanding principal amount of the remaining Senior Notes is $16.1 million and the face value of the Exchange Notes is $137.9 million as of December 31, 2009. In addition, we have reserved $16.1 million from proceeds received from the MMS recoupment to retire the remaining Senior Notes during 2010.

The Company determined that the note exchange should be accounting for in accordance with guidance provided by the FASB for accounting for a troubled debt restructuring. Immediately before the issuance of the Exchange Notes, the total future cash payments on the restructured Senior Notes was less than the remaining carrying amount of the Senior Notes after the carrying amount was reduced by the fair value of the equity interests issued of $11.5 million. Therefore, as of November 23, 2009, in accordance with the troubled debt restructuring accounting standard, the Company reduced the carrying amount of the Senior Notes by the fair value of the common and preferred stock issued. The difference between the adjusted carrying amount of the Senior Notes and the face value of the Exchange Notes was recorded as a deferred credit of $31.2 million which will be amortized as a credit to interest expense at an 8.5% effective interest rate over the life of the Exchange Notes. In addition, the Company incurred $1.0 million of costs associated with the note exchange and expensed the amount in the fourth quarter of 2009 in accordance with the trouble debt restructuring accounting standard. See Note 7 to our Consolidated Financial Statements.

The indentures governing our Exchange Notes and our senior secured credit facility contain various covenants including restrictions on additional indebtedness and payment of cash dividends. In addition, our senior secured credit facility contains covenants for maintenance of certain financial ratios. We were in compliance with these covenants at December 31, 2009.

In April 2008, our wholly owned subsidiary, Callon Entrada, entered into a credit agreement with CIECO Energy (Entrada) LLC ("CIECO Entrada") pursuant to which Callon Entrada could borrow up to $150 million, plus interest expense incurred of up to $12 million, to finance the development of the Entrada project. The Callon Entrada credit agreement is a direct obligation of Callon Entrada. The Callon Entrada credit agreement is secured by a lien on the assets of Callon Entrada, which subsequent to the lease expiration of the Entrada Field, is comprised solely from the remaining related equipment previously purchased during the development phase. Neither Callon Petroleum nor any other subsidiary of Callon Petroleum guaranteed or otherwise agreed to pay the principal or interest payments due on the Callon Entrada credit agreement, so such facility is effectively non-recourse to Callon Petroleum and its other subsidiaries.

During 2008, Callon Entrada borrowed $78.4 million under the facility and as of December 31, 2009. CIECO Entrada had failed to fund $40 million of loan requests which were due in October and November of 2008. We are in discussions with CIECO and CIECO Entrada with regard to these loan requests. No assurances can be made regarding the outcome of these discussions. We do not believe that we have waived any of our rights under our agreements with CIECO or CIECO Entrada.

On April 2, 2009, Callon Entrada received a notice from CIECO Entrada advising Callon Entrada that certain alleged events of default occurred under the credit agreement relating to failure to pay interest when due and the breach of various other covenants related to the decision to abandon the Entrada project. The notice of default received from CIECO Entrada invoked CIECO Entrada's rights under the Callon Entrada credit agreement to accelerate payment of the principal and interest due. The acceleration of payment causes the principal and interest balances under the Callon Entrada credit agreement to be reclassified as current liabilities from long-term liabilities under US GAAP. The agreement has not been legally extinguished and as such under US GAAP, the agreement remains a liability of Callon Entrada. We are currently required to continue to consolidate the financial statements and results of operations of Callon Entrada which results in Callon Entrada's liability being reflected in a separate line item in the consolidated financial statements. Based on the advice of counsel, we believe that the Callon Entrada credit agreement does not obligate Callon or any of its subsidiaries (other than Callon Entrada) to pay principal, accrued interest or other amounts which may be owed under such credit agreement. See Notes 2 and 3 to our Consolidated Financial Statements.

Operating Activities. During the year ended December 31, 2009, net cash provided by operating activities was $26.4 million, a 72% decrease from $93.2 million for the same period in 2008. The decrease in net cash provided by operating activities was largely attributable to the reduction of accounts payable related to the Entrada project and lower commodity prices during the year ended December 31, 2009 as compared to the same period in 2008.

Investing Activities. During the year ended December 31, 2009, net cash used in investing activities was $49.8 million as compared to $8.7 million for the same period in 2008. The increase in net cash used in investing activities is the timing of payments associated with capital costs incurred during 2008 for the Entrada project and paid during 2009.

Financing Activities. During the year ended December 31, 2009, net cash provided by financing activities was $10.0 million as compared to net cash used in financing activities of $120.7 million for the same period in 2008. The increase in cash provided by net financing activities is primarily attributable to the debt retirement of the $200 million senior secured revolving credit agreement during 2008 that was used to purchase BP Exploration and Production Company's interest in the Entrada Fields. See Note 3 to our Consolidated Financial Statements.

Our current planned capital expenditures for 2010 total $58 million and include capitalized interest and general and administrative expenses. The current portion of our asset retirement obligation will require an additional $4 million resulting in capital expenditures of $62 million for 2010. The current capital expenditure plans for 2010 include:

- drilling and completing up to 16 wells in the Permian Basin;
- drilling two wells in the Haynesville Shale play;
- lease and seismic acquisition; and
- capitalized interest and overhead.

We believe that our cash on hand and operating cash flow along with our credit facility, if needed, will be adequate to meet our capital, debt repayment, and operating requirements for 2010. We fund our day-to-day operating expenses and capital expenditures from operating cash flow, supplemented as needed by borrowings under our credit facilities.

The following table describes our outstanding contractual obligations as of December 31, 2009 (in thousands):

	Payments due by Period				
Contractual Obligations	Total	Less Than One Year	One-Three Years	Three-Five Years	More Than-Five Years
Senior Secured Credit Facility	$ 10,000	$ —	$ 10,000	$ —	$ —
13% Senior Notes	137,961	—	—	—	137,961
9.75% Senior Notes	16,052	16,052	—	—	—
Throughput Commitments:					
Medusa Oil Pipeline	163	61	62	27	13
	$164,176	$ 16,113	$ 10,062	$ 27	$137,974

The Callon Entrada non-recourse credit agreement is not included in the contractual obligations table because it is a direct obligation of Callon Entrada, an indirect, wholly owned subsidiary of Callon. Neither Callon nor any other subsidiary of Callon guaranteed or otherwise agreed to pay the principal and interest payments due on the Callon Entrada non-recourse credit agreement, so this agreement is effectively non-recourse to Callon and its other subsidiaries. See Notes 2 and 3 to our Consolidated Financial Statements.

Off-Balance Sheet Arrangements

We have a 10% ownership interest in Medusa Spar LLC ("LLC"), which is a limited liability company that owns a 75% undivided ownership interest in the deepwater spar production facilities at our Medusa Field in the Gulf of Mexico. In December 2003, we contributed a 15% undivided ownership interest in the production facility to the LLC in return for approximately $25 million in cash and a 10% ownership interest in the LLC. The LLC earns a tariff based upon production volume throughput from the Medusa area. We are obligated to process our share of production from the Medusa Field and any future discoveries in the area through the spar production facilities. This arrangement allowed us to defer the cost of the spar production facility over the life of the Medusa Field. Our cash proceeds were used to reduce the balance outstanding under our senior secured credit facility. The LLC used the cash proceeds from $83.7 million of non-recourse financing and a cash contribution by one of the LLC owners to acquire its 75% interest in the spar. In the second quarter at 2008, the non-recourse financing was extinguished. The balance of Medusa Spar LLC is owned by Oceaneering International, Inc. and Murphy. We are accounting for our 10% ownership interest in the LLC under the equity method.

Results of Operations

The following table sets forth certain operating information with respect to our oil and gas operations for each of the three years in the period ended December 31, 2009.

	December 31, 2009	2008	2007
Production:			
Oil (MBbls)	1,012	942	1,063
Gas (MMcf)	5,740	5,839	12,340
Total production (MMcfe)	11,809	11,494	18,718
Average daily production (MMcfe)	32.4	31.4	51.3
Average sales price:			
Oil (per Bbl) (a)	$ 73.00	$ 88.07	$ 67.63
Gas (per Mcf)	$ 4.78	$ 9.99	$ 8.01
Total (per Mcfe)	$ 8.57	$ 12.29	$ 9.12
Oil and gas revenues (in thousands):			
Oil revenue	$ 73,842	$ 82,963	$ 71,891
Gas revenue	27,417	58,349	98,877
Total	$101,259	$141,312	$170,768
Lease operating expenses (in thousands)	$ 18,447	$ 19,208	$ 27,795
Additional per Mcfe data:			
Sales price	$ 8.57	$ 12.29	$ 9.12
Lease operating expenses	1.56	1.67	1.48
Operating margin	$ 7.01	$ 10.62	$ 7.64
Depletion	$ 2.83	$ 5.57	$ 3.89
General and administrative (net of management fees)	$ 1.13	$ .83	$ .53

(a) Below is a reconciliation of the average NYMEX price to the average realized sales price per barrel of oil:

	2009	2008	2007
Average NYMEX oil price	$ 61.80	$ 99.67	$ 72.33
Basis differential and quality adjustments	(4.64)	(1.15)	(4.08)
Transportation	(1.32)	(1.15)	(1.15)
Hedging	17.16	(9.30)	0.53
Average realized oil price	$ 73.00	$ 88.07	$ 67.63

Comparison of Results of Operations for the Years Ended December 31, 2009 and 2008

Oil and Gas Revenues

Total oil and gas revenues decreased 28% from $141.3 million in 2008 to $101.3 million in 2009 due to lower oil and gas pricing. Total production on an equivalent basis for 2009 increased 3% from 2008 production.

Gas production during 2009 totaled 5.7 Bcf and generated $27.4 million in revenues compared to 5.8 Bcf and $58.3 million in revenues during the same period in 2008. Average gas prices realized for 2009 were $4.78 per Mcf compared to $9.99 per Mcf during the same period in 2008. The 2% decrease in 2009 production was primarily normal and expected declines from our legacy properties.

Oil production during 2009 totaled 1,012,000 barrels and generated $73.8 million in revenues compared to 942,000 barrels and $83.0 million in revenues for the same period in 2008. Average oil prices realized in 2009 were $73.00 per barrel compared to $88.07 per barrel in 2008. See the Results of Operations table for a reconciliation of the realized oil prices to average NYMEX. The 7% increase in 2009 production was primarily due to the 2009 volumes associated with the MMS royalty recoupment for the Medusa Field. See Note 12 to our Consolidated Financial Statements.

Lease Operating Expenses

Lease operating expenses for 2009 decreased by 4% to $18.4 million compared to $19.2 million for the same period in 2008. The decrease was primarily due to a lower number of producing wells in the Gulf of Mexico Shelf area. Four of our gas wells were shut-in during 2008 due to early water production and are plugged and abandoned or scheduled for plugging and abandonment. In addition, our High Island Block A-540 well was shut-in during the second quarter of 2008, due to a plugged flowline, which management determined uneconomic to repair. This well was plugged in the second half of 2009.

Depreciation, Depletion and Amortization

Depreciation, depletion and amortization for 2009 and 2008 totaled $33.4 million and $64.1 million, respectively. The 48% decrease was due to a lower depletion rate resulting from the full-cost ceiling writedown, which was recorded in the fourth quarter of 2008 and the downward revision of plugging and abandonment cost for the Entrada field during 2009.

Impairment of Oil and Gas Properties

During the fourth quarter of 2008, capitalized costs of oil and gas properties, net of accumulated amortization and deferred taxes relating to oil and gas properties, exceeded the sum of (1) the estimated future net revenues from proved reserves at current prices discounted at 10% and (2) the lower of cost or market of unevaluated properties, net of tax effects. As a result, $485.5 million of excess costs was expensed as an impairment of oil and gas properties for the year ended December 31, 2008. See Note 15 to the Consolidated Financial Statements.

Accretion Expense

Accretion expense for 2009 and 2008 of $3.1 million and $4.2 million, respectively, represents accretion of our asset retirement obligations. See Note 11 to the Consolidated Financial Statements.

General and Administrative

General and administrative expenses for 2009, net of amounts capitalized, were $13.4 million compared to $9.6 million in 2008. The 43% increase was primarily due to the $2.2 million of nonrecurring expenses for staffing reductions and retirements and the result of overhead fees of approximately $2.6 million received during the second half of 2008 as operator of the Entrada Field, which was recorded as a reduction to general and administrative expenses in 2008.

Acquisition Expense

As a result of the ExL acquisition, we incurred $298,000 of costs in the fourth quarter of 2009 for consultant and legal expenses. See Note 13 to our Consolidated Financial Statements.

Interest Expense

Interest expense related to debt obligations decreased to $19.1 million in 2009 compared to $24.0 million in 2008. This 20% decrease was due to the retirement in April 2008 of the $200 million senior revolving credit facility associated with the Entrada acquisition. See Note 7 to the Consolidated Financial Statement for more details.

Callon Entrada Non-Recourse Credit Agreement Interest Expense

We incurred interest expense under the Callon Entrada credit agreement for the twelve-month periods ended December 31, 2009 and 2008 of $7.1 million and $2.7 million, respectively. The increase was due to a larger outstanding loan balance for the twelve-month period ended December 31, 2009 and an increase in the interest rate due to the notice of default received from CIECO on April 2, 2009. Principal and related interest was payable from the assets of Callon Entrada, primarily production from the Entrada Field with no recourse to the assets of Callon. Accordingly, due to the abandonment of the Entrada project, no cash payments for principal or interest have been made by Callon Entrada except with proceeds from our 50% share of the sale of surplus equipment. See Note 3 to the Consolidated Financial Statements for details.

Loss on Early Extinguishment of Debt

Due to the early extinguishment of the $200 million senior revolving credit facility on April 8, 2008, we incurred expenses of $11.9 million consisting of $6.3 million in cash pre-payment penalties plus a non-cash charge of $5.6 million related to the amortization expense associated with the deferred financing costs related to the senior revolving credit facility. See Note 7 to the Consolidated Financial Statements for more details.

Debt Restructuring Expense

As a result of the 9.75% Senior Note exchange for the 13% Senior Notes we incurred $1.0 million of financing cost in the fourth quarter of 2009 for consultant and legal expenses. See Note 7 to the Consolidated Financial Statements for more details.

Income Taxes

For 2009, income tax expense was zero compared to an income tax benefit of $39.7 million in 2008. The income tax benefit in 2008 was primarily the result of expensing the impairment of oil and gas properties in the amount of $485.5 million. We established a valuation allowance of $128.1 million as of December 31, 2008. We revised the valuation allowance for the twelve-month period ended December 31, 2009 as a result of current year ordinary income, the impact of which is included in our effective tax rate. See Note 6 to the Consolidated Financial Statements.

Comparison of Results of Operations for the Years Ended December 31, 2008 and 2007

Oil and Gas Revenues

Total oil and gas revenues decreased 17% from $170.8 million in 2007 to $143.1 million in 2008 primarily due to lower gas production. Total production on an equivalent basis for 2008 decreased by 39% versus 2007.

Gas production during 2008 totaled 5.8 Bcf and generated $58.3 million in revenues compared to 12.3 Bcf and $98.9 million in revenues during the same period in 2007. Average gas prices realized for 2008 were $9.99 per Mcf compared to $8.01 per Mcf during the same period in 2007. The 53% decrease in 2008 production was primarily due to the sale of our Mobile Bay Field on Blocks 952, 953, and 955, effective May 1, 2007, a lower number of producing wells, downtime resulting from Hurricanes Gustav and Ike and normal and expected declines in production from our older properties. Three of our gas wells were shut-in due to early water production, two of which are now scheduled for plugging and abandonment, and the third was sold for the plugging and abandonment liability. In addition, our High Island Block A-540 well was shut in during the second quarter of 2008, due to a plugged flowline, and management has determined it to be uneconomic to repair.

Oil production during 2008 totaled 942,000 barrels and generated $83.0 million in revenues compared to 1,063,000 barrels and $71.9 million in revenues for the same period in 2007. Average oil prices realized in 2008 were $88.07 per barrel compared to $67.63 per barrel in 2007. The 11% decrease in 2008 production was primarily due to downtime resulting from Hurricanes Gustav and Ike and normal and expected declines in producing wells. In addition, our High Island Block A-540 well was shut in during the second quarter of 2008, due to a plugged flowline, and management has determined it to be uneconomic to repair. See the Results of Operations table for a reconciliation of the realized oil prices to average NYMEX.

Lease Operating Expenses

Lease operating expenses for 2008 decreased by 31% to $19.2 million compared to $27.8 million for the same period in 2007. The decrease was primarily due to the sale of the Mobile Bay Field on Blocks 952, 953 and 955 effective May 1, 2007, a lower number of producing wells and downtime in the third and fourth quarters of 2008 caused by Hurricanes Gustav and Ike resulting in lower throughput charges. Three of our gas wells were shut-in due to early water production, two of which are now scheduled for plugging and abandonment, and the third was sold for the plugging and abandonment liability. In addition, our High Island Block A-540 well was shut in during the second quarter of 2008, due to a plugged flowline, and management has determined it to be uneconomic to repair.

Depreciation, Depletion and Amortization

Depreciation, depletion and amortization for 2008 and 2007 totaled $64.1 million and $72.8 million, respectively. The 12% decrease was due to lower production volumes which were partially offset by a higher depletion rate. The 43% increase in the depletion rate from 2007 to 2008 was higher Entrada development costs in addition to the abandonment of operations.

Impairment of Oil and Gas Properties

During the fourth quarter of 2008, capitalized costs of oil and gas properties, net of accumulated amortization and deferred taxes relating to oil and gas properties exceeded the sum of (1) the estimated future net revenues from proved reserves at current prices discounted at 10% and (2) the lower of cost or market of unevaluated properties, net of tax effects. As a result, $485.5 million of excess costs was expensed as an impairment of oil and gas properties for the year ended December 31, 2008. See Note 15 to the Consolidated Financial Statements.

Accretion Expense

Accretion expense for 2008 and 2007 of $4.2 million and $4.0 million, respectively, represents accretion of our asset retirement obligations. See Note 11 to the Consolidated Financial Statements.

General and Administrative

General and administrative expenses for 2008, net of amounts capitalized, were $9.6 million compared to $9.9 million in 2007, or a 3% decrease.

Interest Expense

Interest expense decreased to $26.7 million in 2008 compared to $34.3 million in 2007. This decrease was due to the retirement of the $200 million senior revolving credit facility associated with the Entrada acquisition. See Note 7 to the Consolidated Financial Statement for more details.

Loss on Early Extinguishment of Debt

Due to the early extinguishment of the $200 million senior revolving credit facility on April 8, 2008, we incurred expenses of $11.9 million consisting of $6.3 million in cash pre-payment penalties plus a non-cash charge of $5.6 million related to the amortization expense associated with the deferred financing costs related to the senior revolving credit facility. See Note 7 to the Consolidated Financial Statements for more details.

Income Taxes

For 2008, we recorded an income tax benefit of $39.7 million compared to an income tax expense of $8.5 million in 2007. The income tax benefit in 2008 was primarily the result of expensing the impairment of oil and gas properties in the amount of $485.5 million. We evaluated our deferred income tax asset in light of our reserve quantity estimates, our long-term outlook for oil and gas prices and our expected level of future revenues and expenses and based upon this evaluation, we believe it is more likely than not, that we will not realize the recorded deferred income tax asset. As a result, we have established a valuation allowance in the amount of $128.1 million, as of December 31, 2008, the amount of the deferred income tax asset. See Note 6 to the Consolidated Financial Statements.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISKS

Commodity Price Risk

Our revenues are derived from the sale of our crude oil and natural gas production. Prices for oil and gas remain extremely volatile, sometimes experiencing large fluctuations as a result of relatively small changes in supply, weather conditions, economic conditions and government actions. From time to time, we enter into derivative financial instruments to manage oil and gas price risk.

We may utilize fixed price “swaps,” which reduce our exposure to decreases in commodity prices and limit the benefit we might otherwise have received from any increases in commodity prices.

We may utilize price “collars” to reduce the risk of changes in oil and gas prices. Under these arrangements, no payments are due by either party as long as the market price is above the floor price and below the ceiling price set in the collar. If the price falls below the floor, the counter-party to the collar pays the difference to us, and if the price rises above the ceiling, the counter-party receives the difference from us.

We may purchase “puts” which reduce our exposure to decreases in oil and gas prices while allowing realization of the full benefit from any increases in oil and gas prices. If the price falls below the floor, the counter-party pays the difference to us.

We enter into these various agreements from time to time to reduce the effects of volatile oil and gas prices and do not enter into derivative transactions for speculative purposes. However, certain of our derivative positions may not be designated as hedges for accounting purposes. See Note 8 to the Consolidated Financial Statements for a description of our hedged position at December 31, 2009.

Based on projected annual sales volumes for 2010 (excluding production from 2010 exploratory drilling), a 10% decline in the prices we receive for its crude oil and natural gas production would result in an approximate $9.6 million reduction of our revenues.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

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Report of Independent Registered Public Accounting Firm

The Board of Directors and Stockholders of
Callon Petroleum Company

We have audited the accompanying consolidated balance sheets of Callon Petroleum Company as of December 31, 2009 and 2008, and the related consolidated statements of operations, stockholders' equity (deficit) and cash flows for each of the three years in the period ended December 31, 2009. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Callon Petroleum Company as of December 31, 2009 and 2008, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2009, in conformity with U.S. generally accepted accounting principles.

As discussed in Note 2 to the financial statements, in 2008 the Company changed its method of accounting for income taxes. In 2009, the Company changed its reserve estimates and related disclosures as a result of adopting new oil and gas reserve estimation and disclosure requirements.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Callon Petroleum Company's internal control over financial reporting as of December 31, 2009, based on criteria established in Internal Control —Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated March 12, 2010, expressed an unqualified opinion thereon.

/s/Ernst & Young LLP

New Orleans, Louisiana
March 12, 2010

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CALLON PETROLEUM COMPANY
CONSOLIDATED BALANCE SHEETS
(In thousands, except share data)

	December 31, 2009	December 31, 2008
ASSETS		
Current assets:		
Cash and cash equivalents	$ 3,635	$ 17,126
Accounts receivable	20,798	44,290
Accounts receivable-MMS royalty recoupment	51,534	—
Fair market value of derivatives	145	21,780
Other current assets	1,572	1,103
Total current assets	77,684	84,299
Oil and gas properties, full-cost accounting method:		
Evaluated properties	1,593,884	1,581,698
Less accumulated depreciation, depletion and amortization	(1,488,718)	(1,455,275)
	105,166	126,423
Unevaluated properties excluded from amortization	25,442	32,829
Total oil and gas properties	130,608	159,252
Other property and equipment, net	2,508	2,536
Restricted investments	4,065	4,759
Investment in Medusa Spar LLC	11,537	12,577
Other assets, net	1,589	2,667
Total assets	$ 227,991	$ 266,090
LIABILITIES AND STOCKHOLDERS' EQUITY (DEFICIT)		
Current liabilities:		
Accounts payable and accrued liabilities	$ 12,887	$ 76,516
Asset retirement obligations	4,002	9,151
9.75% Senior Notes	15,820	—
	32,709	85,667
Callon Entrada (non-recourse) credit facility (See Note 3)	84,847	—
Total current liabilities	117,556	85,667
Senior Notes (See Note 7)		
Principal outstanding	137,961	200,000
Deferred credit	31,213	—
Discount	—	(5,580)
Total Senior Notes	169,174	194,420
Senior secured revolving credit facility	10,000	
Callon Entrada (non-recourse) credit facility (See Note 3)	—	81,154
Total long-term debt	179,174	275,574
Asset retirement obligations	10,648	33,043
Other long-term liabilities	1,467	1,610
Total liabilities	308,845	395,894
Stockholders' equity (deficit):		
Preferred Stock, $.01 par value; 2,500,000 shares authorized;	—	—
Common Stock, $.01 par value; 60,000,000 shares authorized; 28,742,926 shares and 21,621,142 shares issued outstanding at December 31, 2009 and 2008, respectively	287	216
Capital in excess of par value	243,898	227,803
Other comprehensive income (loss)	(7,478)	14,157
Retained (deficit) earnings	(317,561)	(371,980)
Total stockholders' equity (deficit) (See Note 2)	(80,854)	(129,804)
Total liabilities and stockholders' equity (deficit)	$ 227,991	$ 266,090

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

Callon Petroleum Company
Consolidated Statements of Operations
(In thousands, except per share amounts)

	Year Ended December 31, 2009	2008	2007
Operating revenues:			
Oil sales	$ 73,842	$ 82,963	$ 71,891
Gas sales	27,417	58,349	98,877
MMS royalty recoupment (See Note 12)	40,886	—	—
Total operating revenues	142,145	141,312	170,768
Operating expenses:			
Lease operating expenses	18,447	19,208	27,795
Depreciation, depletion and amortization	33,443	64,054	72,762
General and administrative	13,355	9,565	9,876
Accretion expense	3,149	4,172	3,985
Acquisition expenses (See Note 13)	298	—	—
Derivative expense	—	498	—
Impairment of oil and gas properties	—	485,498	—
Total operating expenses	68,692	582,995	114,418
Income (loss) from operations	73,453	(441,683)	56,350
Other (income) expenses:			
Interest expense	19,089	23,986	34,329
Callon Entrada (non-recourse) credit facility interest expense (See Note 3)	7,072	2,719	—
Loss on early extinguishment of debt	—	11,871	—
9.75% Senior Notes restructuring expenses (See Note 7)	1,024	—	—
Interest on MMS royalty recoupment	(7,681)	—	—
Other (income) expense	190	(1,379)	(1,172)
Total other (income) expenses	19,694	37,197	33,157
Income (loss) before income taxes	53,759	(478,880)	23,193
Income tax (benefit) expense	—	(39,725)	8,506
Income (loss) before equity in earnings of Medusa Spar LLC	53,759	(439,155)	14,687
Equity in earnings of Medusa Spar LLC	660	262	507
Net income (loss) available to common shares	$ 54,419	$(438,893)	$ 15,194
Net income (loss) per common share:			
Basic	$ 2.47	$ (20.68)	$ 0.73
Diluted	$ 2.45	$ (20.68)	$ 0.71
Shares used in computing net income (loss) per share amounts:			
Basic	22,072	21,222	20,776
Diluted	22,200	21,222	21,290

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

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CALLON PETROLEUM COMPANY
CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY (DEFICIT)
(In thousands)

	Preferred Stock	Common Stock	Capital in Excess of Par Value	Accumulated Other Comprehensive Income (Loss)	Total Retained Earnings (Deficit)	Stock-holders' Equity (Deficit)
Balances, December 31, 2006	$ —	$ 207	$220,785	$ 8,652	$ 51,759	$ 281,363
Comprehensive income:						
Net income	—	—	—	—	15,194	
Other comprehensive loss	—	—	—	(12,035)	—	
Total comprehensive income						3,159
Tax benefits related to stock compensation plans	—	—	163	—	—	163
Restricted stock	—	2	2,388	—	—	2,390
Balances, December 31, 2007	—	209	223,336	(3,383)	66,913	287,075
Comprehensive income (loss):						
Net loss	—	—	—	—	(438,893)	
Other comprehensive income	—	—	—	17,540	—	
Total comprehensive loss						(421,353)
Shares issued pursuant to employee benefit and option plan	—	1	(1,153)	—	—	(1,152)
Tax benefits related to stock compensation plans	—	—	2,050	—	—	2,050
Restricted stock	—	1	3,575	—	—	3,576
Warrants	—	5	(5)	—	—	—
Balances, December 31, 2008	—	216	227,803	14,157	(371,980)	(129,804)
Comprehensive income:						
Net income	—	—	—	—	54,419	
Other comprehensive loss	—	—	—	(21,635)	—	
Total comprehensive income						32,784
Shares issued pursuant to employee benefit and option plan	—	1	205	—	—	206
Restricted stock	—	1	4,432	—	—	4,433
Common stock issued-note exchange	—	69	11,458	—	—	11,527
Balances, December 31, 2009	$ —	$ 287	$243,898	$ (7,478)	$(317,561)	$ (80,854)

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

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CALLON PETROLEUM COMPANY
CONSOLIDATED STATEMENTS OF CASH FLOWS
(In thousands)

	Years Ended December 31, 2009	2008	2007
Cash flows from operating activities:			
Net income (loss)	$ 54,419	$(438,893)	$ 15,194
Adjustments to reconcile net income (loss) to cash provided by operating activities:			
Depreciation, depletion and amortization	34,274	64,862	73,677
Impairment of oil and gas properties	—	485,498	—
Accretion expense	3,149	4,172	3,985
Amortization of deferred financing costs	2,522	4,185	3,009
Non-cash interest expense for Callon Entrada credit agreement	3,693	—	—
Non-cash loss on early extinguishment of debt	—	5,598	—
Equity in earnings of Medusa Spar, LLC	(660)	(262)	(507)
Deferred income tax (benefit) expense	18,816	(167,848)	8,506
Valuation allowance	(18,816)	128,123	—
Non-cash charge related to compensation plans	2,335	1,550	849
Excess tax benefits from share-based payment arrangements	—	(2,050)	(163)
Changes in current assets and liabilities:			
Accounts receivable	(45,573)	(22,215)	6,658
Other current assets	(468)	5,489	(619)
Current liabilities	(27,260)	22,987	(2,057)
Change in gas balancing receivable	279	630	(938)
Change in gas balancing payable	(312)	156	889
Change in other long-term liabilities	(12)	2,708	(10)
Change in other assets, net	(31)	(1,458)	810
Cash provided by operating activities	26,355	93,232	109,283
Cash flows from investing activities:			
Capital expenditures	(35,790)	(176,536)	(127,409)
ExL acquisition	(15,756)	—	—
Entrada acquisition	—	—	(150,000)
Proceeds from sale of mineral interests	—	167,349	60,931
Distribution from Medusa Spar, LLC	1,700	498	687
Cash used by investing activities	(49,846)	(8,689)	(215,791)
Cash flows from financing activities:			
Increases in debt	20,337	94,435	229,000
Payments on debt	(10,337)	(216,000)	(64,000)
Deferred financing costs	—	—	(6,429)
Equity issued related to employee stock plans	—	(1,152)	—
Excess tax benefits from share-based payment arrangements	—	2,050	163
Capital leases	—	—	(872)
Cash provided by (used in) financing activities	10,000	(120,667)	157,862
Net (decrease) increase in cash and cash equivalents	(13,491)	(36,124)	51,354
Cash and cash equivalents:			
Balance, beginning of period	17,126	53,250	1,896
Balance, end of period	$ 3,635	$ 17,126	$ 53,250

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

CALLON PETROLEUM COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. ORGANIZATION

General

Callon Petroleum Company ("the Company" or "Callon") was organized under the laws of the state of Delaware in March 1994 to serve as the surviving entity in the consolidation and combination of several related entities (referred to herein collectively as the "Constituent Entities"). The combination of the businesses and properties of the Constituent Entities with the Company was completed on September 16, 1994 ("Consolidation").

As a result of the Consolidation, all of the businesses and properties of the Constituent Entities are owned (directly or indirectly) by the Company. Certain registration rights were granted to the stockholders of certain of the Constituent Entities. See Note 14.

The Company and its predecessors have been engaged in the acquisition, development and exploration of crude oil and natural gas since 1950. The Company's properties are geographically concentrated onshore in Louisiana and Texas and the offshore waters of the Gulf of Mexico.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Principles of Consolidation and Reporting

The Consolidated Financial Statements include the accounts of the Company, and its subsidiary, Callon Petroleum Operating Company ("CPOC"). CPOC also has subsidiaries, namely Callon Offshore Production, Inc., Callon Entrada Company ("Callon Entrada") and Mississippi Marketing, Inc. All intercompany accounts and transactions have been eliminated. Certain prior year amounts have been reclassified to conform to presentation in the current year.

Use of Estimates

The preparation of financial statements in conformity with United States generally accepted accounting principles ("US GAAP") requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Asset Retirement Obligations

The Company is required to record its estimate of the fair value of liabilities for obligations associated with the retirement of tangible long-lived assets and the associated asset retirement costs. Interest is accreted on the present value of the asset retirement obligation and reported as accretion expense within operating expenses in the consolidated statements of operations. See Note 11.

Oil and Gas Properties

The Company follows the full-cost method of accounting for oil and gas properties whereby all costs incurred in connection with the acquisition, exploration and development of oil and gas reserves, including certain overhead costs, are capitalized. Such amounts include the cost of drilling and equipping productive wells, dry hole costs, lease acquisition costs, delay rentals, interest capitalized on unevaluated leases, other costs related to exploration and development activities, and site restoration, dismantlement and abandonment costs capitalized in accordance with asset retirement obligation accounting guidance. Costs capitalized include salaries and related fringe benefits paid to employees directly engaged in the acquisition, exploration and/or development of oil and gas properties as well as other directly identifiable general and administrative costs associated with such activities. Such capitalized costs ($10.1 million in 2009, $12.6 million in 2008 and $10.8 million in 2007) do not include any costs related to production or general corporate overhead. Costs associated with unevaluated properties, including capitalized interest on such costs, are excluded from amortization. Unevaluated property costs are transferred to evaluated property costs at such time as wells are completed on the properties or management determines that these costs have been impaired.

Costs of oil and gas properties, including future development costs, which have proved reserves and properties which have been determined to be worthless, are depleted using the unit-of-production method based on proved reserves. If the total capitalized costs of oil and gas properties net of accumulated amortization and deferred taxes relating to oil and gas properties exceed the sum of (1) the estimated future net revenues from proved reserves at current prices discounted at 10% and (2) the lower of cost or market of unevaluated properties, net of tax effects (the full-cost ceiling amount), then such excess is charged to expense during the period in which the excess occurs. See Note 15.

Upon the acquisition or discovery of oil and gas properties, management estimates the future net costs to be incurred to dismantle, abandon and restore the property using available geological, engineering and regulatory data. Such cost estimates are periodically updated for changes in conditions and requirements. In accordance with asset retirement obligation guidance issued by the Financial Accounting Standards Board ("FASB"), such costs are capitalized to the full-cost pool when the related liabilities are incurred. In accordance with Securities and Exchange Commission ("SEC") Staff Accounting Bulletin No. 106, assets recorded in connection with the recognition of an asset retirement obligation are included as part of the costs subject to the full-cost ceiling limitation. The future cash outflows associated with settling the recorded asset retirement obligations are excluded from the computation of the present value of estimated future net revenues used in determining the full-cost ceiling amount.

Sales of oil and gas properties are accounted for as adjustments to the net full cost pool with no gain or loss recognized, unless the adjustment would significantly alter the relationship between capitalized costs and proved reserves.

Amendments to Oil and Gas Reserves Estimation and Disclosure Requirements

In December 2008, the SEC approved amendments to its oil and gas reserves estimation and disclosure requirements. The amendments, among other things:

- allow the use of reliable technologies to estimate proved reserves if those technologies have been demonstrated to result in reliable conclusions about reserve volumes;
- require disclosure of oil and gas proved reserves by significant geographic area;
- permit the optional disclosure of probable and possible reserves;
- modify the prices used to estimate reserves for SEC disclosure purposes to a 12-month average beginning-of-the-month price instead of a period-end price; and

- require that if a third party is primarily responsible for preparing or auditing the reserve estimates, the company make disclosures relating to the independence and qualifications of the third party, including filing as an exhibit any report received from the third party.

Additionally, during January 2010, the FASB issued accounting guidance to align the reserve calculation and disclosure requirements of US GAAP with the new SEC oil and gas reserve estimation and disclosure rules.

The new requirements are effective for the Company's year-end financial statements and its Annual Report on Form 10-K for the year ended December 31, 2009.

Property and Equipment

Depreciation of other property and equipment is provided using the straight-line method over estimated lives of three to 20 years. Depreciation expense of $423,000, $437,000 and $457,000 relating to other property and equipment was included in general and administrative expenses in the Company's consolidated statements of operations for the years ended December 31, 2009, 2008 and 2007, respectively. The accumulated depreciation on other property and equipment was $11.8 million and $11.6 million as of December 31, 2009 and 2008, respectively.

Investment in Medusa Spar LLC

The Company has a 10% ownership interest in Medusa Spar, LLC ("LLC"), which is a limited liability company that owns a 75% undivided ownership interest in the deepwater spar production facilities on Callon's Medusa Field in the Gulf of Mexico. In December 2003, the Company contributed a 15% undivided ownership interest in the production facility to the LLC in return for approximately $25 million in cash and a 10% ownership interest in the LLC. The LLC earns a tariff based upon production volume throughput from the Medusa area. Callon is obligated to process its share of production from the Medusa Field and any future discoveries in the area through the spar production facilities. This arrangement allowed Callon to defer the cost of the spar production facility over the life of the Medusa Field. The Company's cash proceeds were used to reduce the balance outstanding under its senior secured credit facility. The LLC used the cash proceeds from $83.7 million of non-recourse financing and a cash contribution by one of the LLC owners to acquire its 75% interest in the spar. During the second quarter of 2008, the non-recourse financing was extinguished. The balance of Medusa Spar LLC is owned by Oceaneering International, Inc. (NYSE:OII) and Murphy Oil Corporation (NYSE:MUR). The Company is accounting for its 10% ownership interest in the LLC under the equity method.

Revenue Recognition and Gas Balancing

The Company recognizes revenue under the entitlement method of accounting. Under the method, revenue is deferred for deliveries in excess of the Company's net revenue interest, while revenue is accrued for the undelivered volumes. Production imbalances are generally recorded at the estimated sale price in effect at the time of production. Gas balancing receivables were $743,000 and $1.0 million as of December 31, 2009 and 2008, respectively. Gas balancing payables were $1.2 million and $1.5 million as of December 31, 2009 and 2008, respectively.

Derivatives

The Company periodically uses derivative financial instruments to manage oil and gas price risk on a limited amount of its future production, and does not use these instruments for trading purposes. Settlement of derivative contracts is generally based on the difference between the contract price or prices specified in the derivative instrument and a New York Mercantile Exchange (“NYMEX”) price or other cash or futures index price.

The Company’s derivative contracts that are accounted for as cash flow hedges are recorded at fair market value and the changes in fair value are recorded through other comprehensive income (loss), net of tax, in stockholders’ equity. The cash settlements on these contracts are recorded as an increase or decrease in oil and gas sales. The changes in fair value related to ineffective derivative contracts are recognized as derivative expense (income). The cash settlement on these contracts is also recorded within derivative expense (income). See Note 8.

Callon’s derivative contracts are carried at fair value on the Company’s consolidated balance sheet under the caption “Fair Market Value of Derivatives”. The oil and gas derivative contracts are settled based upon reported prices on NYMEX. The estimated fair value of these contracts is based upon closing exchange prices on NYMEX and in the case of collars and floors, the time value of options.

In March 2008, the FASB issued guidance for disclosures about derivative instruments and hedging activities. Under the guidance for disclosures about derivative instruments and hedging activities, entities are required to provide enhanced disclosures about (a) how and why an entity uses derivative instruments, (b) how derivative instruments and related hedged items are accounted for under US GAAP, and (c) how derivative instruments and related hedged items affect an entity’s financial position, financial performance, and cash flows. The Company adopted the guidance on January 1, 2009 and has added certain additional disclosures to its financial statements.

Fair Value Measurements

Effective January 1, 2008, the Company adopted guidance issued by the FASB for fair value measurements. The guidance for fair value measurements defines fair value, establishes a framework for measuring fair value and requires enhanced disclosures about fair value measurements. The adoption of the fair value measurements guidance did not have a significant impact on the Company’s financial statements. The Company also adopted guidance issued by the FASB for the fair value option for financial assets and liabilities on January 1, 2008, which permits entities to choose to measure various financial instruments and certain other items at fair value. The adoption of the fair value option for financial assets and liabilities guidance did not have an impact on the Company’s financial statements. See Note 9.

Income Taxes

Provisions for income taxes include deferred taxes resulting primarily from temporary differences due to different reporting methods for oil and gas properties for financial reporting purposes and income tax purposes. US GAAP requires the recognition of a deferred tax asset for net operating loss carryforwards, statutory depletion carryforward and tax credit carryforwards, net of a valuation allowance. The valuation allowance is provided for that portion of the asset for which it is deemed more likely than not will not be realized. See Note 6.

Earnings per Share

The Company accounts for earnings per share ("EPS") in accordance with guidance issued by the FASB. The guidance on accounting for earnings per share requires all entities with publicly held common stock or potential common stock must disclose EPS — basic and diluted. Basic EPS is computed by dividing reported earnings available to common stockholders by weighted average shares outstanding. Diluted EPS reflects the potential dilution that could occur if securities or other contracts to issue common stock were exercised or converted into common stock or resulted in the issuance of common stock that then shared in the earnings of the entity. The earnings component of EPS is limited to earnings applicable to common shares or earnings after deduction of preferred stock dividends if incurred. If discontinued operations, extraordinary items, and /or the cumulative effect of a change in accounting principles are reported, EPS information is required for each of the following: (a) income from continuing operations, (b) income before extraordinary items, (c) the cumulative effect of the change in accounting principle, net of tax, and (d) net income. See Note 5.

In June 2008, the FASB issued guidance determining whether instruments granted in share-based payment transactions are participating securities. The guidance addresses whether instruments granted in share-based payment transactions are participating securities prior to vesting and, therefore, need to be included in the earnings allocation in computing earnings per share under the two-class method described in the FASB issued guidance for earning per share". The Company adopted this guidance on January 1, 2009 with no impact to its financial statements.

Stock-Based Compensation

Share-based compensation requires the cash flows from tax benefits resulting from tax deductions in excess of compensation cost recognized for stock options exercised (excess tax benefits) to be classified as financing cash flows. The $2.1 million and $163,000 of excess tax benefits classified as a financing cash inflow for the years ended December 31, 2008 and 2007, respectively would have been classified as an operating cash flow had the Company not adopted the guidance issued by the FASB for share-based compensation. There were no stock option exercises in the years ended December 31, 2009 and 2007 and no cash proceeds from the exercise of stock options for the year ended December 31, 2008 due to the fact that all options were exercised through net-share settlements. See Note 4.

Accounts Receivable

Accounts receivable consists primarily of accrued oil and gas production receivables. The balance in the reserve for doubtful accounts netted within accounts receivable was $65,000 at both December 31, 2009 and 2008. There were no provisions to expense in the three-year period ended December 31, 2009.

Major Customers

The Company's production is generally sold on month-to-month contracts at prevailing prices. The following table identifies customers to whom it sold a significant percentage of its total oil and gas production during each of the years ended:

	December 31,		
	2009	2008	2007
Shell Trading Company	45%	33%	25%
Plains Marketing, L.P.	23%	23%	10%
Louis Dreyfus Energy Services	15%	16%	20%
StatoilHydro	—	—	13%

Because alternative purchasers of oil and gas are readily available, the Company believes that the loss of any of these purchasers would not result in a material adverse effect on its ability to market future oil and gas production.

Cash and Cash Equivalents

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

Statements of Cash Flows

The Company paid no federal income taxes for the three years in the period ended December 31, 2009. During the years ended December 31, 2009, 2008 and 2007, the Company made cash payments for interest of $19.8 million, $27.0 million and $37.6 million, respectively.

During the fourth quarter of 2009, the Company commenced an exchange offer for any and all of its outstanding Senior Notes. For each $1,000 principal amount of outstanding Senior Notes tendered in accordance with the terms and conditions of the exchange offer, each tendering holder of the Senior Notes received $750 principal amount of 13% Senior Secured Notes due 2016 (“Exchange Notes), 20.625 shares of common stock and 1.6875 shares of Convertible Preferred Stock. On December 31, 2009, each share of the Convertible Preferred Stock was automatically converted by the Company into 10 shares of common stock following shareholder approval and the filing of an amendment to the Company’s charter increasing the number of authorized shares of common stock as necessary to accommodate such conversion. Holders of approximately 92% of the Senior Notes tender their notes in the exchange offer and 6.9 million shares of common stock, after the Convertible Preferred Stock was converted into common shares, were issued to the tendering notes holders. See Note 7.

Fair Value of Financial Instruments

Fair value of cash and cash equivalents, accounts receivable and accounts payable, approximated book value at December 31, 2009 and 2008. The senior secured revolving credit facility had a balance outstanding of $10.0 million at December 31, 2009 and the fair value approximated book value at December 31, 2009. The Company’s 9.75% Senior Notes due 2010 had an estimated fair market value of 95% and 52% of face value at December 31, 2009 and 2008, respectively. The Company’s 13% Senior Notes due 2016 had an estimated fair market value of 75% of face value at December 31, 2009. Callon Entrada’s non-recourse credit agreement had a fair market value of zero at December 31, 2009.

Business Combinations

In December 2007, the FASB issued an accounting standard to improve the relevance, representational faithfulness, and comparability of the information that a reporting entity provides in its financial reports about a business combination and its effects. To accomplish that, the standard establishes principles and requirements for how the acquirer (a) recognizes and measures in its financial statements the identifiable assets acquired, the liabilities assumed, and any noncontrolling interest in the acquiree, (b) recognizes and measures the goodwill acquired in the business combination or a gain from a bargain purchase, and (c) determines what information to disclose to enable users of the financial statements to evaluate the nature and financial effects of the business combination. The business combination guidance is effective for business combinations with an acquisition date on or after the beginning of annual reporting period beginning on or after December 15, 2008. The standard requires an acquirer to recognize 100% of the fair values of acquired assets, with limited exceptions, even if the acquirer has not acquired 100% of its target. Additionally contingent consideration arrangements and preacquisition contingencies will be measured at fair value on the acquisition date and included in the basis of the purchase price. Transaction costs are expensed as incurred and not considered as part of the fair value of the acquisition; however, acquired research and development are no longer expensed at acquisition, but instead are capitalized as an indefinite-lived intangible asset. The Company adopted this accounting standard on January 1, 2009, and was applied to the Company's ExL acquisition during 2009. See Note 13 for the impact of the acquisition on the financial statements.

Subsequent Events

In May 2009, the FASB issued guidance for subsequent events. The objective of this guidance is to establish general standards of accounting for and disclosures of events that occur after the balance sheet date but before financial statements are issued or are available to be issued. The Company adopted the guidance as of the quarter ended June 30, 2009 with limited impact to its financial statements. See Note 20.

Recent Accounting Pronouncements

Consolidation of Variable Interest Entities ("VIE"). In June 2009, the FASB issued an accounting standard which amends US GAAP as follows: a) to require an enterprise to perform an analysis to determine whether the enterprise's variable interest or interests give it a controlling financial interest in a VIE, identifying the primary beneficiary of a VIE, b) to require ongoing reassessment of whether an enterprise is the primary beneficiary of a VIE, rather than only when specific events occur, c) to eliminate the quantitative approach previously required for determining the primary beneficiary of a VIE. d) to amend certain guidance for determining whether an entity is a VIE, e) to add an additional reconsideration event when changes in facts and circumstances pertinent to a VIE occur, f) to eliminate the exception for troubled debt restructuring regarding VIE reconsideration, and g) to require advanced disclosures that will provide users of financial statement with more transparent information about an enterprise's involvement in a VIE. This pronouncement is effective for the first annual reporting period that begins after November 15, 2009, with earlier adoption prohibited. The Company adopted this pronouncement on January 1, 2010. Upon adoption, the Company reevaluated its interest in its subsidiary, Callon Entrada as a result of the amendments described above. Based on the evaluation performed, management has concluded that a VIE reconsideration event had taken place resulting in the determination that Callon Entrada is a VIE, for which the Company is not the primary beneficiary. Therefore, effective January 1, 2010, Callon Entrada will be deconsolidated from the consolidated financial statements of the Company. Deconsolidation will result in the removal of approximately $1.8 million of current assets, $2.0 million of current liabilities, $30.0 million of deferred tax assets, $30.0 million of valuation allowance and approximately $84.8 million of non-recourse debt and related obligation for the cumulative amount of interest. Retained earnings will be increased by $85.1 million as a cumulative effect of change related to this accounting standard.

The following table shows the impact of deconsolidation as of January 1, 2010.

Balance Sheet (in thousands)	Callon Consolidated as reported 12/31/09	Callon Entrada Deconsolidation	Callon After Deconsolidation
Total current assets	$ 77,684	$ (1,767)	$ 75,917
Total oil and gas properties	130,608	—	130,608
Other property and equipment	2,508	—	2,508
Other assets	17,191	—	17,191
Total assets	$ 227,991	$ (1,767)	$ 226,224
Other current liabilities	$ 16,889	$ (2,015)	$ 14,874
9.75% Senior Notes, due December 2010	15,820	—	15,820
Callon Entrada credit agreement	84,847	(84,847)	—
Total current liabilities	117,556	(86,862)	30,694
Total long-term debt	179,174	—	179,174
Total other long-term liabilities	12,115	—	12,115
Total stockholders’ equity (deficit)	(80,854)	85,095	4,241
Total liabilities and stockholders’ equity (deficit)	$ 227,991	$ (1,767)	$ 226,224

The Company also reevaluated its interest in its equity method investment, Medusa Spar LLC, upon the adoption of this accounting standard. No changes in the Company’s accounting of Medusa Spar LLC resulted from the adoption of this accounting standard.

Noncontrolling Interest in Consolidated Financial Statements. In December 2007, the FASB issued an accounting standard for noncontrolling interest in consolidated financial statements. The objective of this standard is to improve 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 standard is effective for first fiscal year and interim periods within the fiscal year, beginning on or after December 15, 2008. The Company adopted this standard on January 1, 2009 with no impact to its financial statements.

Accounting for Convertible Debt Instruments That May Be Settled in Cash Upon Conversion. Effective January 1, 2009, the FASB issued an accounting standard for accounting for convertible debt instruments that may be settled in cash upon conversion (including partial cash settlement). Additionally, this standard specifies that issuers of such instruments should separately account for the liability and equity components in a manner that will reflect the entity’s nonconvertible debt borrowing rate when interest cost is recognized in subsequent periods. The Company’s adoption of this standard had no impact to its financial statements.

Business Combinations — Identifiable Assets, Liabilities and Any Noncontrolling Interest. In April 2009, the FASB issued accounting guidance for business combinations that arise from contingencies. The guidance addresses application issues raised by preparers, auditors, and members of the legal profession on initial recognition and measurement, subsequent measurement and accounting, and disclosure of assets and liabilities arising from contingencies in a business combination. The Company adopted this guidance as of the quarter ended June 30, 2009 with no impact to the Company’s financial statements.

Fair Value of Financial Instruments for Interim Reporting Periods. The Company adopted the accounting guidance issued by the FASB for fair value of financial instruments for interim reporting periods which requires disclosures about fair value of financial instruments for interim reporting periods of publicly traded companies as well as in annual financial statements. This guidance also amends the guidance for interim reporting, to require those disclosures in summarized financial information at interim reporting periods. Accordingly, the Company adopted this guidance as of the quarter ended June 30, 2009 with limited impact to the Company's financial statements.

Financial Accounting Standards Board Accounting Standards Codification. The FASB voted to approve the FASB Accounting Standards Codification ("ASC") as the single source of authoritative nongovernmental US GAAP as of July 1, 2009. ASC was effective for interim and annual periods ending after September 15, 2009. ASC reorganizes the many US GAAP pronouncements into approximately 90 accounting topics, with all topics using a consistent structure. It also includes relevant authoritative content issued by the SEC, as well as selected SEC staff interpretations and administrative guidance. ASC does not change or alter existing US GAAP and effective July 1, 2009, changes to ASC were communicated through an Accounting Standards Update ("ASU"). The Company adopted ASC for the September 30, 2009 reporting period with no impact on the consolidated financial statements.

3. CALLON ENTRADA CREDIT AGREEMENT

In April 2008, Callon completed the sale of a 50% working interest in the Entrada Field to CIECO Energy (US) Limited ("CIECO") effective January 1, 2008. At closing, CIECO paid Callon $155 million and reimbursed the Company $12.6 million for 50% of Entrada capital expenditures incurred prior to the closing date. In addition, as part of the purchase and sale agreement, CIECO agreed to loan the Company up to $150 million for its share of the development costs for the Entrada project.

A wholly-owned subsidiary of Callon, Callon Entrada, entered into a credit agreement with CIECO Energy (Entrada) LLC, ("CIECO Entrada") pursuant to which Callon Entrada was entitled to borrow up to $150 million, plus interest expense incurred of up to $12 million, to finance the development of the Entrada project prior to the abandonment of the project in November 2008. Based on the terms of the credit agreement, the debt was to be repaid solely from assets, primarily production, from the Entrada field. As a result of abandoning the project prior to completion and the lease expiring on June 1, 2009, Callon Entrada's only source of payment is the proceeds from the sale of equipment purchased but not used for the Entrada project. The agreement bears interest at six-month LIBOR (as in effect on the first day of each interest period) plus 375 basis points and is subject to customary representations, warranties, covenants and events of default. The interest rate increased by 400 basis points as of April 2, 2009 due to a notice of default received from CIECO Entrada, which is discussed below. As of December 31, 2009, $78.4 million of principal and $6.4 million of interest were outstanding under this facility.

On April 2, 2009, Callon Entrada received a notice from CIECO Entrada advising Callon Entrada that certain alleged events of default occurred under the credit agreement relating to failure to pay interest when due and the breach of various other covenants related to the decision to abandon the Entrada project. The notice of default received from CIECO Entrada invoked CIECO Entrada's rights under the Callon Entrada credit agreement to accelerate payment of the principal and interest due. The acceleration of payment caused the principal and interest balances under the Callon Entrada credit agreement to be reclassified effective as of the date of notice to current liabilities from long-term liabilities under US GAAP. The agreement has not been legally extinguished, and as such under US GAAP, the agreement remains as a liability of Callon Entrada. Until January 1, 2010, the Company is required to continue to consolidate the financial statements and results of operations of Callon Entrada, and as such, Callon Entrada's liability is reflected in a separate line item in Callon's consolidated financial statements.

All assets of Callon Entrada, and its stock, are pledged to CIECO Entrada under the Callon Entrada credit agreement. Callon and its subsidiaries (other than Callon Entrada) did not guarantee the Callon Enrada credit facility and, based on the advice of legal counsel, the Company believes that it and its subsidiaries are not otherwise obligated to repay the principal, accrued interest or any other amount which may become due under the Callon Entrada credit facility. However, Callon has entered into a customary indemnification agreement pursuant to which it agrees to indemnify the lenders under the Callon Entrada credit facility against Callon Entrada's misappropriation of funds, non-performance of certain covenants, excluding the events of default discussed above, and similar matters. In addition, Callon also guaranteed the obligations of Callon Entrada to fund its proportionate share of any operating costs related to the Entrada project that Callon Entrada may, from time to time, expressly approve under the Entrada joint operating agreement for which none remain nor are planned. Callon also has guaranteed Callon Entrada's payment of all amounts to plug and abandon wells and related facilities and for a breach of law, rule or regulation (including environmental laws) and for any losses of CIECO Entrada attributable to gross negligence of Callon Entrada. The well for which Callon Entrada was responsible was plugged and abandoned in the fourth of quarter of 2008, and the Minerals Management Service ("MMS") confirmed to Callon during 2009 that all abandonment obligations in the Entrada field have been satisfied.

Prior to abandonment of the Entrada project, CIECO Entrada failed to fund two loan requests totaling $40 million under the Callon Entrada credit agreement. These loan requests were to cover Callon Entrada's share of the costs incurred to develop the Entrada field up to the suspension of the project. Such amounts were subsequently funded by the Company to Callon Entrada and were included as part of the Company's full-cost pool impairment adjustment recorded in the fourth quarter of 2008. The Company continues to discuss with CIECO Entrada its failure to fund the $40 million in loan requests.

CIECO Entrada also failed to fund its working interest share of a settlement payment in the amount of $7.3 million to terminate a drilling contract for the Entrada Project. No assurances can be made regarding the outcome of discussions related to the Company's ability to recover its funds related to the Entrada Project. The Company does not believe that we have waived any of our rights under the agreements with CIECO Entrada or its parent, CIECO.

As of December 31, 2009, the wind down of the Entrada project was complete and all of the costs related to the Entrada project have been paid. The lease expired June 1, 2009 and reverted to the MMS. In addition, the sale of equipment purchased for the Entrada project, but not used, is in progress. As of December 2009, Callon Entrada has collected $3.4 million in sales proceeds from the sale of equipment, net to its interest, which was applied to unpaid interest expense as required under the Callon Entrada credit facility. The Company believes that the amount of future operating costs of Callon Entrada, for which the Company would be responsible for, is not significant and is limited to minimal storage fees for the surplus equipment, while the equipment is being liquidated.

The Company adopted the pronouncement for consolidation of variable interest entities on January 1, 2010. Upon adoption, the Company reevaluated its interest in its subsidiary, Callon Entrada. Based on the evaluation performed, management has concluded that a VIE reconsideration event had taken place resulting in the determination that Callon Entrada is a VIE, for which the Company is not the primary beneficiary and Callon Entrada will be deconsolidated from the Company's consolidated financial statements as of January 1, 2010. See Note 2 above under "Recent Accounting Pronouncements" for more details.

4. STOCK-BASED COMPENSATION

The Company has various stock plans ("Plans") under which employees of the Company and its subsidiaries and non-employee members of the Board of Directors of the Company have been or may be granted certain stock-based compensation. For further discussion of the Plans, refer to Note 16.

For the year ended December 31, 2009, the Company recorded stock-based compensation expense of $4.8 million, of which $2.3 million was included in general and administrative expenses and $2.5 million was capitalized to oil and gas properties. For the year ended December 31, 2008, the Company recorded stock-based compensation expense of $4.5 million, of which $2.5 million was included in general and administrative expenses and $2.0 million was capitalized to oil and gas properties. For the year ended December 31, 2007, the Company recorded stock-based compensation expense of $2.9 million, of which $1.4 million was included in general and administrative expenses and $1.5 million was capitalized to oil and gas properties. Shares available for future stock option or restricted stock grants to employees and directors under existing plans were 1,290,387 at December 31, 2009.

Stock Options

The Company uses the Black-Scholes option pricing model to estimate the fair value of stock option awards with the following weighted-average assumptions for the indicated periods. There were no stock options issued during 2008.

		Years Ended December 31,	
	2009	2008	2007
Dividend yield	—	—	—
Expected volatility	136.0%	—	36.2%
Risk-free interest rate	3.9%	—	4.7%
Expected life of option (in years)	9	—	5
Weighted-average grant-date fair value	$ 1.23	—	$5.64
Forfeiture rate	0.0%	—	2.0%

The assumptions above are based on multiple factors, including historical exercise patterns of employees with respect to exercise and post-vesting employment termination behaviors, expected future exercising patterns and the historical volatility of the Company's stock price.

The following table represents stock option activity for the three years ended December 31:

	2009		2008		2007	
	Shares	Wtd Avg Ex Price	Shares	Wtd Avg Ex Price	Shares	Wtd Avg Ex Price
Outstanding, beginning of year	513,275	$ 10.27	755,225	$ 10.00	740,225	$ 9.93
Granted (at market)	500,000	2.76	—	—	30,000	14.27
Exercised	—	—	(238,950)	9.34	—	—
Forfeited	(15,000)	14.44	(3,000)	15.97	—	—
Expired	(19,917)	9.99	—	—	(15,000)	15.31
Outstanding, end of year	978,358	$ 6.37	513,275	$ 10.27	755,225	$ 10.00
Exercisable, end of year	464,558	$ 9.93	488,075	$ 9.91	710,225	$ 9.57
Weighted-average remaining						
Contract life:						
Outstanding options at end of period	5.75 yrs.		2.92 yrs.		3.39 yrs.	
Outstanding exercisable at end of period	1.78 yrs.		2.68 yrs.		3.08 yrs.	

As of December 31, 2009 and 2008, the aggregate intrinsic value of options outstanding and options exercisable was zero. As of December 31, 2007, the aggregate intrinsic value of options outstanding was $5.0 million and the aggregate intrinsic value of options exercisable was $4.9 million. Total intrinsic value of options exercised was $4.1 million for the year ended December 31, 2008. At December 31, 2009, there was $54,000 of unrecognized compensation cost related to nonvested stock options, which is expected to be recognized over one year.

Restricted Stock

The Plans allow for the issuance of restricted stock awards. The unearned stock-based compensation related to these awards is being amortized to compensation expense on a straight-line basis over the requisite service period for the entire award. The compensation expense for these awards was determined based on the market price of our stock at the date of grant applied to the total numbers of shares that were anticipated to fully vest. As of December 31, 2009, there was $3.2 million of unrecognized compensation cost associated with these awards, which is expected to be recognized over a weighted average period of 1.5 years.

The following table represents unvested restricted stock activity for the year ended December 31, 2009:

	Number of Shares	Weighted-Average Grant-Date Fair Value
Outstanding shares at beginning of period	509,300	$ 17.43
Granted	650,975	1.98
Vested	(157,750)	15.00
Forfeited	(75,100)	17.36
Outstanding shares at end of period	927,425	$ 7.01

For the years ended December 31, 2009, 2008 and 2007 the Company recognized non-cash compensation expense associated with the restricted stock awards of $4.6 million, $4.3 million and $2.7 million, respectively.

As part of the 2009 award, 121,525 shares were issued as stock appreciation rights (“SARs”). The SARs will vest three years from grant date. At December 31, 2009, the Company had recorded a stock-based compensation liability of $182,000 for this award.

5. NET INCOME PER SHARE

Basic net income per common share was computed by dividing net income by the weighted average number of shares of common stock outstanding during the year. Diluted net income per common share was determined on a weighted average basis using common shares issued and outstanding adjusted for the effect of stock options and restricted stock considered common stock equivalents computed using the treasury stock method.

A reconciliation of the basic and diluted net income per share computation is as follows for the years ended December 31 (in thousands, except per share amounts):

	2009	2008	2007
(a) Net income (loss) available to common shares	$54,419	$(438,893)	$15,194
(b) Weighted average shares outstanding	22,072	21,222	20,776
Dilutive impact of stock options	—	—	148
Dilutive impact of restricted stock	128	—	40
Dilutive impact of warrants	—	—	326
(c) Weighted average shares outstanding for diluted net income per share	22,200	21,222	21,290
Stock options excluded due to the exercise price being greater than the stock price	978	399	75
Basic net income (loss) per share (a¸b)	$ 2.47	$ (20.68)	$ 0.73
Diluted net income (loss) per share (a¸c)	$ 2.45	$ (20.68)	$ 0.71

In addition, below are the shares (in thousands) relating to stock option, warrants and restricted stock that were not included in diluted shares for the year ended December 31, 2008 due to the fact that the Company had a loss for this period. The Company had net income for the years ended December 31, 2009 and 2007 and all such shares were included as described above.

	2008
Stock options	161
Warrants	328
Restricted Stock	129

6. INCOME TAXES

Below is an analysis of deferred income taxes:

	December 31,	
	2009	2008
	(In thousands)	
Deferred tax assets:		
Federal net operating loss carryforwards	$ 94,125	$ 68,432
Statutory depletion carryforward	4,895	4,561
Alternative minimum tax credit carryforward	383	375
Asset retirement obligations	3,704	13,102
Oil and gas properties	—	58,061
Other	34,170	.2,241
Valuation allowance	(116,676)	(128,123)
Total deferred tax assets	20,601	18,649
Deferred tax liabilities:		
Oil and gas properties	9,555	—
Other	11,046	18,649
Total deferred tax liabilities	20,601	18,649
Net deferred tax	$ —	$ —

US GAAP provides for the weighing of positive and negative evidence in determining whether it is more likely than not that a deferred tax asset is recoverable. As a result of the impairment of oil and gas properties in the fourth quarter of 2008, the Company incurred losses on an aggregate basis for the three-year period ended December 31, 2008. As a result, the Company has established a full valuation allowance for its net deferred tax asset which reflects federal net operating loss carryforwards of $268 million as of December 31, 2009.

If not utilized, the Company's federal net operating loss carryforwards will expire in 2013 through 2024. The Company's state net operating loss carryforwards in the amount of $56.8 million as of December 31, 2009 will expire in 2010 through 2024. The Company has limited state taxable income as primarily all of its revenue is generated in federal waters and is not subject to state income taxes. Accordingly, the Company has established a full valuation allowance on the tax benefit associated with these state net operating loss carryforwards as the Company does not anticipate generating taxable state income in the states in which these carryforwards apply.

The Company had no significant unrecognized tax benefits at the date of adoption or at December 31, 2009. Accordingly, the Company does not have any interest or penalties related to uncertain tax positions. However, if interest or penalties were to be incurred related to uncertain tax positions, such amounts would be recognized in income tax expense. Tax periods for years 2004 through 2008 remain open to examination by the federal and state taxing jurisdictions to which the Company is subject.

Below is a reconciliation of the reported amount of income tax expense attributable to continuing operations for the year to the amount of income tax expense that would result from applying domestic federal statutory tax rates to pretax income from continuing operations.

	Years Ended December 31,		
	2009	2008	2007
Income tax expense computed at the statutory federal income tax rate	(35)%	(35)%	35%
Change in valuation allowance	34%	27%	—
Other	1%	—	2%
Effective income tax rate	0%	(8)%	37%

Included in the table below are the components of income tax expense.

	Years Ended December 31,		
	2009	2008	2007
Current income tax expense (benefit)	$ —	$ —	$ —
Deferred income tax (benefit) expense	18,816	(167,848)	8,506
Valuation allowance	(18,816)	128,123	—
Total income tax expenses	$ —	$ (39,725)	$ 8,506

During 2009, the Company reduced the valuation allowance by the income tax expense incurred for the year.

7. LONG-TERM DEBT

Long-term debt consisted of the following at:

	December 31,	
	2009	2008
	(In Thousands)	
Senior Secured Credit Facility (matures September 25, 2012)	$ 10,000	$ —
9.75% Senior Notes (due December 2010)	16,052	200,000
Discount	(232)	(5,580)
13% Senior Notes (due September 2016)	137,961	—
Deferred Credit	31,213	—
Callon Entrada (non-recourse) credit agreement	84,847	78,435
Total long-term debt	279,841	272,855
Less current portion	100,667	—
Long-term portion	$179,174	$272,855

Senior Secured Credit Facility. On September 25, 2008, the Company completed a $250 million second amended and restated senior secured revolving credit agreement with Union Bank N.A. ("Union Bank") as administrative agent and issuing lender. The borrowing base was $16.2 million at December 31, 2009. Borrowings under the credit agreement are secured by mortgages covering the Company's major fields. As of December 31, 2009, $10.0 million was outstanding under the agreement. The credit facility bears interest at 0% to 0.50% above a defined base rate depending on utilization of the borrowing base or, at the option of the Company, LIBOR plus 1.375% to 2.0% based on utilization of the borrowing base. Under the senior secured credit facility, a commitment fee of 0.25% or 0.375% per annum, depending on the amount of the unused portion of the borrowing base, is payable quarterly. The range of interest rates on the senior secured credit facility during 2009 was 1.87% to 3.25%.

Subsequent to December 31, 2009, the Company's senior secured credit agreement was amended to include Regions Bank as the sole arranger and administrative agent. The third amended and restated senior secured credit agreement, which matures on September 25, 2012, provides for a $100 million facility with an initial borrowing base of $20 million, which will be reviewed and re-determined on a semi-annual basis. The third amended and restated credit facility bears interest at 4% above a defined base rate and in no event will the interest rate be less than 6%. In addition, a commitment fee of 0.5% per annum on the unused portion of the borrowing base, is payable quarterly. Subsequent to December 31, 2009, simultaneously with the execution of the third amended and restated senior secured credit agreement, the Company repaid the $10 million outstanding on the borrowing base under the second amended and restated senior secured credit agreement. See Note 20.

9.75% Senior Notes due 2010. In the fourth quarter of 2003, the Company issued $200 million of 9.75% senior notes ("Senior Notes"), due 2010. In conjunction with the Senior Notes, the Company issued warrants to purchase 2.775 million shares of its common stock at an exercise price of $10 per share and an expiration date of December 2010. The warrants were valued at $10.6 million and were treated as a discount on the debt. The Senior Notes mature December 8, 2010 and have an effective interest rate of 11.4%. The Company recorded the issuance of the Senior Notes at a fair value of $185 million. Deferred costs of $15 million associated with the Senior Notes are being amortized over the life of the notes. As of December 31, 2009, 2.410 million of the 2.775 million warrants issued with the Senior Notes were exercised.

During the fourth quarter of 2009, Callon commenced an exchange offer for any and all of its outstanding Senior Notes. For each $1,000 principal amount of outstanding Senior Notes tendered in accordance with the terms and conditions of the exchange offer, each tendering holder of the Senior Notes received $750 principal amount of 13% Senior Secured Notes due 2016 ("Exchange Notes), 20.625 shares of common stock and 1.6875 shares of Convertible Preferred Stock. Holders of approximately 92% of the Senior Notes tendered their Senior Notes in the exchange offer. On December 31, 2009, each share of the Convertible Preferred Stock was automatically converted by the Company into 10 shares of common stock following shareholder approval and the filing of an amendment to the Company's charter increasing the number of authorized shares of common stock as necessary to accommodate such conversion. In connection with the exchange offer, holders who tendered their Senior Notes consented to amend the indenture governing the Senior Notes, eliminating substantially all of the indenture's restrictive covenants. The principal amount of the remaining Senior Notes is $16.1 million at December 31, 2009 and is due in 2010.

13% Senior Notes due 2016 ("Exchange Notes"). As described above, during the fourth quarter of 2009, the Company exchanged approximately 92% of the principal amount, or $183.9 million, of the Senior Notes for $137.9 million of Exchange Notes plus 3.8 million shares of common stock and 310,802 shares of Convertible Preferred Stock which was valued on November 24, 2009 in the amount of $11.5 million and recorded as an increase to stockholders' equity. On December 31, 2009, each share of the Convertible Preferred Stock was automatically converted by the Company into 10 shares of common stock following shareholder approval and the filing of an amendment to the Company's charter increasing the number of authorized shares of common stock as necessary to accommodate such conversion.

The Company determined that the note exchange should be accounted for in accordance with guidance provided by the FASB for accounting for troubled debt restructuring. Immediately before the issuance of the Exchange Notes, the total future cash payments on the restructured Senior Notes was less than the remaining carrying amount of the Senior Notes after the carrying amount was reduced by the fair value of the equity interests issued. Therefore, as of November 23, 2009, in accordance with the troubled debt restructuring accounting standard, the Company reduced the carrying amount of the Senior Notes by the fair value of the common and preferred stock issued in the amount of $11.5 million The difference between the adjusted carrying amount of the Senior Notes and the face value of the Exchange Notes was recorded as a deferred credit of $31.2 million which will be amortized as a credit to interest expense at an 8.5% effective interest rate over the life of the Exchange Notes. In addition, the Company incurred $1.0 million of costs associated with the note exchange and expensed the amount in the fourth quarter of 2009 in accordance with troubled debt restructuring accounting standard.

Certain of the Company's subsidiaries guarantee the Company's obligations under the Exchange Notes. The subsidiary guarantors are 100% owned, all of the guarantees are full and unconditional and joint and several, the parent company has no independent assets or operations and any subsidiaries of the parent company other than the subsidiary guarantors are minor.

Restrictive Covenants. The Indenture governing our Exchange Notes and the Company's senior secured credit facility contains various covenants including restrictions on additional indebtedness and payment of cash dividends. In addition, Callon's senior secured credit facility contains covenants for maintenance of certain financial ratios. The Company was in compliance with these covenants at December 31, 2009.

Callon Entrada (Non-Recourse) Credit Agreement. A wholly-owned subsidiary of Callon, Callon Entrada, entered into a credit agreement with CIECO Entrada in April 2008, pursuant to which Callon Entrada may borrow up to $150 million, plus interest expense incurred of up to $12 million, to finance the development of the Entrada project. The Callon Entrada credit agreement is a direct obligation of Callon Entrada. The Callon Entrada credit agreement is secured by a lien on the assets of Callon Entrada, which generally are comprised of the Entrada Field and related equipment. Neither Callon Petroleum nor any other subsidiary of Callon Petroleum guaranteed or otherwise agreed to pay the principal or interest payments due on the Callon Entrada credit agreement. As such, the facility is effectively non-recourse to Callon Petroleum and its other subsidiaries.

The agreement bears interest at six-month LIBOR (as in effect on the first day of each interest period) plus 0.375% and is subject to customary representations, warranties, covenants and events of default. The interest rate increased by 4.0% as of April 2, 2009 due to a notice of default received from CIECO Entrada. As of December 31, 2009, $78.4 million of principal and $6.4 million of accrued interest was outstanding under this Callon Entrada credit agreement. See Note 3 for more details.

Senior Revolving Credit Facility (due 2014). On April 18, 2007, Callon closed the Entrada acquisition contemporaneous with a seven-year $200 million senior revolving credit facility arranged by Merrill Lynch Capital Corporation, which is secured by a lien on the Entrada properties. On April 8, 2008, Callon extinguished the $200 million senior revolving credit facility. The retirement was made with cash on hand, a $16 million draw under the Union Bank credit facility and proceeds from the sale of a 50% working interest in Callon's Entrada Field to CIECO. Due to the early extinguishment of this credit facility, Callon incurred expenses of $11.9 million, consisting of $6.3 million in pre-payment penalties plus a non-cash charge of $5.6 million related to the amortization expense associated with the deferred financing costs related to the credit facility. These amounts are included in "Loss on early extinguishment of debt" in the accompanying Consolidated Statements of Operations.

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8. DERIVATIVES

During 2008, the change in fair value and settlements of ineffective derivative contracts of $498,000 were related to contracts that were deemed ineffective as a result of a shortfall in production volumes due to downtime resulting from damages caused by Hurricanes Gustav and Ike. No contracts were deemed ineffective during 2009 and 2007. For the years ended December 31, 2009, and 2007 cash settlements on effective cash flow hedges resulted in an increase in oil and gas sales of $19.2 million and $8.1 million, respectively. Cash settlements on effective cash flow hedges for the year ended December 31, 2008 resulted in a reduction in oil and gas sales of $9.4 million.

Listed in the table below are the outstanding derivative contracts, which are collars, as of December 31, 2009:

Product	Volumes per Month	Quantity Type	Average Floor Price	Average Ceiling Price	Period
Natural Gas	75,000	MMBtu	$ 5.00	$ 8.30	01/10-12/10

9. FAIR VALUE MEASUREMENTS

US GAAP establishes a fair value hierarchy which consists of three broad levels that prioritize the inputs to valuation techniques used to measure fair value.

- Level 1 valuations consist of unadjusted quoted prices in active markets for identical assets and liabilities and have the highest priority.
- Level 2 valuations rely on quoted market information for the calculation of fair market value.
- Level 3 valuations are internal estimates and have the lowest priority.

The Company has classified its derivatives into these levels depending upon the data relied on to determine the fair values of the derivative instruments. The fair values of collars and natural gas basis swaps are estimated using internal discounted cash flow calculations based upon forward commodity price curves or quotes obtained from counterparties to the agreements and are designated as Level 3. The following table summarizes the valuation of our assets and liabilities measured at fair value on a recurring basis at December 31, 2009 (in thousands):

	Fair Value Measurements Using			
	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Assets (Liabilities) At Fair Value
Derivative assets	$ —	$ —	$ 145	$ 145
Derivative liabilities	—	—	—	—
Total	$ —	$ —	$ 145	$ 145

The table below presents a reconciliation for assets and liabilities measured at fair value on a recurring basis using significant unobservable inputs (Level 3) during the period ended December 31, 2009. The fair values of Level 3 derivative instruments are estimated using proprietary valuation models that utilize both market observable and unobservable parameters. Level 3 instruments presented in the table consist of net derivatives valued using pricing models incorporating assumptions that, in management's judgment, reflect the assumptions a marketplace participant would have used at December 31, 2009 (in thousands):

	Derivatives
Balance at January 1, 2009	$ 21,780
Total gains or losses (realized or unrealized):	
Included in earnings	19,242
Included in other comprehensive income	(21,635)
Purchases, issuances and settlements	(19,242)
Balance at December 31, 2009	$ 145
Change in unrealized gains (losses) included in earnings relating to derivatives still held as of December 31, 2009	$ —

10. OTHER COMPREHENSIVE INCOME

A summary of the Company's comprehensive income (loss) is detailed below (in thousands, net of tax) for the twelve months ended December 31:

	2009	2008	2007
Net income (loss)	$ 54,419	$(438,893)	$ 15,194
Other comprehensive income (loss):			
Change in fair value of derivatives	(21,635)	17,540	(12,035)
Total comprehensive income (loss)	$ 32,784	$(421,353)	$ 3,159

11. ASSET RETIREMENT OBLIGATIONS

The following table summarizes the activity for the Company's asset retirement obligations (in thousands):

	Years Ended December 31,	
	2009	2008
Asset retirement obligations at beginning of period	$ 42,194	$ 36,837
Accretion expense	3,149	4,172
Liabilities incurred	9	2,851
Liabilities settled	(8,194)	(6,586)
Revisions to estimate	(22,508)	4,920
Asset retirement obligations at end of period	14,650	42,194
Less: current retirement obligations	(4,002)	(9,151)
Long-term retirement obligations	$ 10,648	$ 33,043

The revisions to estimate of $22.5 million was primarily due to the MMS approval to abandon in place the Company's Entrada #1 and #2 wells in place resulting in a reduction in asset retirement obligation liabilities of $16.0 million and reduction in estimated costs for other obligations.

Assets, primarily short-term U.S. Government securities, of approximately $4.1 million at December 31, 2009, were recorded as restricted investments. These assets are held in abandonment trusts dedicated to pay future abandonment costs for several of the Company's oil and gas properties.

12. MMS ROYALTY RECOUPMENT

The Company's Medusa deepwater property is eligible for royalty suspensions pursuant to the Outer Continental Shelf Deep Water Royalty Relief Act 1995. From first production during November 2003 and until August 2009, the Company paid $44.8 million of royalties to the MMS based on price thresholds imposed by the MMS. Kerr-McGee Oil & Gas Corporation sued the MMS on the grounds that the MMS had no right to impose price thresholds on royalty relief leases located in the Gulf of Mexico deep water. In October 2009, the Supreme Court refused to review the decision by the Fifth Circuit Court of Appeals which was in favor of Kerr-McGee. As a result, in November the Company filed for a recoupment of the royalties paid in the amount of $44.8 million from production at the Company's Medusa field. As of December 31, 2009, Callon accrued royalty recoupment of $44.8 million and estimated interest of $7.7 million. The recoupment of principal was received by the Company in January 2010 with the interest expected to be received in the first quarter of 2010.

Royalty recoupment of $3.0 million related to 2009 production was recorded as oil and gas sales in the fourth quarter of 2009. Royalty recoupment for years prior to 2009 of $40.9 million was included in operating revenues as MMS royalty recoupment. Interest income related to the recoupment was recorded as a component of other income and expense.

13. ACQUISITIONS

In September 2009, the Company acquired for $3.0 million a 70% working interest in a 577-acre unit in the heart of the Haynesville Shale play in Bossier Parish, Louisiana. The development plan for this acreage includes drilling a total of seven horizontal wells with the first two wells to be drilled in 2010. Callon will be the operator of this project.

On October 28, 2009, Callon completed the acquisition of proved oil and gas property interests in Wolfberry play located in Crockett, Ector, Midland and Upton Counties, Texas from Ambrose Energy I, Ltd., a subsidiary of ExL Petroleum, LP for a total cash consideration of $16.0 million. The acquisition was funded by the Company's senior secured credit facility in the amount of $10 million and the remaining $6.0 million with cash on hand. The acquisition included year-end proved reserves of 1.6 million barrels of oil equivalent, 22 existing wells producing 350 barrels of oil equivalent per day and upside from a multi-year inventory of drilling and recompletion opportunities. The Company will operate substantially all of the production and development. The Company accounted for the acquisition in accordance with guidance the amended issued by the FASB for business combinations, which was adopted on January 1, 2009, and recorded acquisition expenses in the fourth quarter of 2009 of $298,000.

The following table summarizes the estimated fair value of the assets acquired and liabilities assumed at the acquisition date (In thousands):

Cash paid for acquired assets at closing	$15,958
Post-closing adjustment	(690) (a)
Assumed liabilities	339
Net assets acquired	$15,607

(a) Represents net cash flow from the operations of the acquired properties during the period from September 1, 2008 (effective date) to October 28, 2009 (closing date).

The allocation of the purchase price of the acquired properties at the date of acquisition follows (In thousands):

Accounts receivable	$ 690
Oil and gas properties	15,607
Other accrued liabilities	(339)
Cash paid for acquired assets as closing	$15,958

14. COMMITMENTS AND CONTINGENCIES

From time to time, the Company, as part of the Consolidation and other capital transactions, enters into registration rights agreements whereby certain parties to the transactions are entitled to require the Company to register common stock of the Company owned by them with the SEC for sale to the public in firm commitment public offerings and generally to include shares owned by them, at no cost, in registration statements filed by the Company. Costs of the offering will not include broker's discounts and commissions, which will be paid by the respective sellers of the common stock.

The Company is involved in various claims and lawsuits incidental to its business. In the opinion of management, the ultimate liability hereunder, if any, will not have a material adverse effect on the financial position or results of operations of the Company.

The Company's activities are subject to federal, state and local laws and regulations governing environmental quality and pollution control. Although no assurances can be made, the Company believes that, absent the occurrence of an extraordinary event, compliance with existing federal, state and local laws, rules and regulations governing the release of materials into the environment or otherwise relating to the protection of the environment will not have a material effect upon the capital expenditures, earnings or the competitive position of the Company with respect to its existing assets and operations. The Company cannot predict what effect additional regulation or legislation, enforcement polices hereunder, and claims for damages to property, employees, other persons and the environment resulting from the Company's operations could have on its activities

15. OIL AND GAS PROPERTIES

The following table discloses certain financial data relating to the Company's oil and gas activities, all of which are located in the United States.

	Years Ended December 31,		
	2009	2008 (In thousands)	2007
Capitalized costs incurred:			
Evaluated Properties-			
Beginning of period balance	$1,581,698	$1,349,904	$1,096,907
Property acquisition costs	23,748	6,126	154,193
Exploration costs	—	2,578	35,959
Development costs	(11,562)	223,090	62,845
End of period balance	$1,593,884	$1,581,698	$1,349,904
Unevaluated Properties (excluded from amortization) -			
Beginning of period balance	$ 32,829	$ 70,176	$ 54,802
Additions	6,140	6,409	21,525
Capitalized interest	3,213	6,496	7,152
Transfers to evaluated	(16,740)	(50,252)	(13,303)
End of period balance	$ 25,442	$ 32,829	$ 70,176
Accumulated depreciation, depletion and amortization-			
Beginning of period balance	$1,455,275	$ 738,374	$ 604,682
Provision charged to expense	33,443	549,552	72,762
Sale of mineral interests	—	167,349	60,930
End of period balance	$1,488,718	$1,455,275	$ 738,374

Unevaluated property costs, primarily including lease acquisition costs incurred at federal and state lease sales, unevaluated drilling costs, seismic, capitalized interest and general and administrative costs being excluded from the amortizable evaluated property base, consisted of $8.6 million incurred in 2009, $7.2 million incurred in 2008, and $3.9 million incurred in 2007 and $5.7 million incurred in 2006 and prior. These costs are directly related to the acquisition and evaluation of unproved properties and major development projects. The excluded costs and related reserves are included in the amortization base as the properties are evaluated and proved reserves are established or impairment is determined. The Company expects that the majority of these costs will be evaluated over the next three to five years.

Depletion per unit-of-production (thousand cubic feet of gas equivalent) amounted to $2.83, $5.57 and $3.89 for the years ended December 31, 2009, 2008, and 2007, respectively.

Under the full-cost accounting rules of the SEC, the Company reviews the carrying value of its proved oil and gas properties each quarter. Under these rules, capitalized costs of oil and gas properties, net of accumulated depreciation, depletion and amortization and deferred income taxes, may not exceed the present value of estimated future net cash flows from proved oil and gas reserves, discounted at 10%, plus the lower of cost or fair value of unevaluated properties, net of related tax effects (the full-cost ceiling amount). These rules generally require pricing future oil and gas production at the unescalated market price for oil and gas at the end of each fiscal quarter and require a write-down if the "ceiling" is exceeded. However, if prices recover sufficiently subsequent to the balance sheet date before the release of the financial statements then use of subsequent pricing is allowed and no write-down would be required if such pricing was used. Given the volatility of oil and gas prices, it is reasonably possible that the Company's estimate of discounted future net cash flows from proved oil and gas reserves could change in the near term. If oil and gas prices decline significantly, even if only for a short period of time, it is possible that write-downs of oil and gas properties could occur in the future. For the year ended December 31, 2008, the Company recorded a $485.5 million impairment of oil and gas properties as a result of the ceiling test calculation.

16. EMPLOYEE BENEFIT PLANS

The Company has adopted a series of incentive compensation plans designed to align the interest of the executives and employees with those of its stockholders. The following is a brief description of each plan:

Savings and Protection Plan

The Savings and Protection Plan ("401-K Plan") provides employees with the option to defer receipt of a portion of their compensation, and the Company may, at its discretion, match a portion of the employee's deferral with cash and Company Common Stock. The Company may also elect, at its discretion, to contribute a non-matching amount in cash and Company Common Stock to employees. The amounts held under the 401-K Plan are invested in various funds maintained by a third party in accordance with the directions of each employee. An employee is fully vested, including Company discretionary contributions, immediately upon participation in the 401-K Plan. The total amounts contributed by the Company, including the value of the common stock contributed, were $640,000, $747,000 and $680,000 in the years 2009, 2008 and 2007, respectively.

1996 Stock Incentive Plan

On August 23, 1996, the Board of Directors of the Company approved and adopted the Callon Petroleum Company 1996 Stock Incentive Plan (the "1996 Plan"). The 1996 Plan was approved by the shareholders in 1997 and limited to a maximum of 1,200,000 shares (as amended from the original 900,000 shares) of common stock subject to outstanding awards. The 1996 Plan was amended again and approved on May 9, 2000 at the Annual Meeting of Shareholders, increasing the number of shares reserved for issuance under the 1996 plan to 2,200,000 shares. Unvested options are subject to forfeiture upon certain termination of employment events and expire 10 years from the date of grant.

In August 2006, the Board of Directors approved the award of 520,000 shares of restricted stock from the 1996 Plan. Of the 520,000 shares, 20,000 shares were granted to non-employee members of the Board of Directors and vested immediately. The remaining 500,000 shares were issued to employees of the Company with 20% vesting immediately and the remaining 80% vesting ratably over the next four years. The compensation cost with respect to the 20% that vested immediately was recognized as an expense on the grant date and the compensation cost with respect to the remaining 80% is being amortized to expense over the vesting period.

During 2009, the Company awarded 80,000 shares of restricted stock to non-employee members of the Board of Directors, which will vest one year from the grant date.

2002 Stock Incentive Plan

On February 14, 2002, the Board of Directors of the Company approved and adopted the 2002 Stock Incentive Plan (the “2002 Plan”). Pursuant to the 2002 Plan, 350,000 shares of common stock shall be reserved for issuance upon the exercise of options or for grants of stock options, stock appreciation rights or units, bonus stock, or performance shares or units. This Plan qualified as a “broadly based” plan under the provisions of the New York Stock Exchange’s rules and regulations and therefore did not require shareholder approval. Because the 2002 Plan is a broadly based plan, the aggregate number of shares underlying awards granted to officers and directors cannot exceed 50% of the total number of shares underlying the awards granted to all employees during any three-year period.

In 2006, 17,500 shares were awarded as restricted stock with 20% vesting immediately and the remaining 80% vesting ratably over the next four years. The compensation cost with respect to the 20% that vested immediately was recognized as an expense on the grant date and the compensation cost with respect to the remaining 80% is being amortized to expense over the vesting period.

During 2009, the Company awarded 20,000 share of restricted stock to employees of the Company, which will vest three years from grant date.

2006 Stock Incentive Plan

On March 9, 2006, the Board of Directors of the Company approved the 2006 Stock Incentive Plan (“2006 Plan”). The 2006 Plan was approved by the shareholders at the May 4, 2006 annual meeting. Pursuant to the 2006 Plan, 500,000 shares of common stock shall be reserved for issuance upon exercise of stock options, restricted stock or other stock-based awards. In 2006, 45,000 shares were awarded as restricted stock that will vest ratably over the next four years. The compensation cost with respect to this grant is being amortized to expense over the vesting period.

In April 2008, 217,600 shares were awarded as restricted stock with cliff vesting over the next three years and the compensation cost is being amortized over the vesting period. In addition, 25,000 shares were awarded as restricted stock vesting immediately and the compensation cost was recognized as an expense on the grant date.

During 2009, the Company awarded 179,150 shares of restricted stock to employees of the Company, which will vest three years from grant date. In addition, the Company awarded 8,850 of stock appreciation rights, which vest three years from the grant date.

2009 Stock Incentive Plan

On March 5, 2009, the Board of Directors of the Company approved the Callon Petroleum Company 2009 Stock Incentive Plan (“2009 Plan”), subject to the approval of the shareholders of the Company. The 2009 Plan was approved by shareholders on April 30, 2009. Pursuant to the 2009 Plan, 1,250,000 shares of common stock shall be reserved for issuance upon exercise of vested stock options and stock appreciation rights, restricted stock awards, restricted stock unit awards, and other stock-based awards. During 2009, 171,825 restricted stock units were issued with vesting scheduled for the third anniversary date following the award. In addition, the Company awarded 112,675 of stock appreciation rights, which vest three years from the grant date.

Stock Incentive Award for Inducement of Employment

On June 1, 2009, the Company awarded 100,000 shares of restricted stock, 100,000 shares of performance stock and 500,000 options to the Company's new Executive Vice President and Chief Operating Officer. These shares were issued from the authorized but unissued corporate shares under an exception available by the New York Stock Exchange as a inducement of employment. The restricted stock will vest four years from the grant date, and the performance shares will vest three years from the grant date based on the performance of the Company. The options vest over a ten year period based on the performance of the Company.

17. EQUITY TRANSACTIONS

The Company adopted a stockholder rights plan on March 30, 2000, designed to assure that the Company's stockholders receive fair and equal treatment in the event of any proposed takeover of the Company and to guard against partial tender offers, squeeze-outs, open market accumulations, and other abusive tactics to gain control without paying all stockholders a fair price. The rights plan was not adopted in response to any specific takeover proposal. Under the rights plan, the Company declared a dividend of one right ("Right") on each share of the Company's Common Stock. Each Right will entitle the holder to purchase one one-thousandth of a share of a Series B Preferred Stock, par value $0.01 per share, at an exercise price of $90 per one one-thousandth of a share.

The Rights are not currently exercisable, and will become exercisable only in the event a person or group acquires, or engages in a tender or exchange offer to acquire, beneficial ownership of 15 percent or more (one existing stockholder was granted an exception for up to 21 percent) of the Company's common stock. After the Rights become exercisable, each Right will also entitle its holder to purchase a number of common shares of the Company having a market value of twice the exercise price. The dividend distribution was made to stockholders of record at the close of business on April 10, 2000. The Rights will expire on March 30, 2010.

During the fourth quarter of 2009, Callon commenced an exchange offer for any and all of its outstanding Senior Notes. For each $1,000 principal amount of outstanding Senior Notes tendered in accordance with the terms and conditions of the exchange offer, each tendering holder of the Senior Notes will receive $750 principal amount of 13% Senior Secured Notes due 2016 ("Exchange Notes), 20.625 shares of common stock and 1.6875 shares of Convertible Preferred Stock. On December 31, 2009, each share of the Convertible Preferred Stock was automatically converted by the Company into 10 shares of common stock following shareholder approval and the filing of an amendment to the Company's charter increasing the number of authorized shares of common stock as necessary to accommodate such conversion. Holders of approximately 92% of the Senior Notes tender their notes in the exchange offer and 6.9 million shares of common stock, after the Convertible Preferred Stock was converted into common shares, were issued to the tendering notes holders.

18. SUPPLEMENTAL OIL AND GAS RESERVE DATA (UNAUDITED)

The Company's proved oil and gas reserves at December 31, 2009, 2008 and 2007 have been estimated by Huddleston & Co., Inc., the Company's independent petroleum engineers. The reserves were prepared in accordance with guidelines established by the SEC. Accordingly, the following reserve estimates are based upon existing economic and operating conditions.

There are numerous uncertainties inherent in establishing quantities of proved reserves. The following reserve data represents estimates only and should not be construed as being exact. In addition, the standardized measure of discounted future net cash flows should not be construed as the current market value of the Company's oil and gas properties or the cost that would be incurred to obtain equivalent reserves.

Estimated Reserves

Changes in the estimated net quantities of crude oil and natural gas reserves, all of which are located onshore and offshore in the continental United States, are as follows:

Reserve Quantities

	Years Ended December 31,		
	2009	2008	2007
Proved developed and undeveloped reserves:			
Crude Oil (MBbls):			
Beginning of period	6,027	24,531	13,265
Revisions to previous estimates	(356)	(9,026)	(1,152)
Change in ownership	563	—	144
Purchase of reserves in place	1,257	—	13,658
Sale of reserves in place	—	(8,536)	(356)
Extensions and discoveries	—	—	35
Production	(1,012)	(942)	(1,063)
End of period	6,479	6,027	24,531
Natural Gas (MMcf):			
Beginning of period	18,651	116,454	66,037
Revisions to previous estimates	3,632	(49,526)	(3,022)
Change in ownership	420	—	192
Purchase of reserves in place	2,140	—	68,068
Sale of reserves in place	—	(42,542)	(3,690)
Extensions and discoveries	—	105	1,209
Production	(5,740)	(5,840)	(12,340)
End of period	19,103	18,651	116,454
Proved developed reserves:			
Crude Oil (MBbls):			
Beginning of period	4,663	4,723	5,159
End of period	4,346	4,663	4,723
Natural Gas (MMcf):			
Beginning of period	13,463	22,340	36,750
End of period	12,301	13,463	22,340

Standardized Measure

The following tables present the Company's standardized measure of discounted future net cash flows and changes therein relating to proved oil and gas reserves, and were computed using reserve valuations based on regulations prescribed by the SEC. These regulations provide that the oil and gas price structure utilized to project future net cash flows reflect the average of the preceding 12-month, first of the month product prices (approximately $4.75 per Mcf for natural gas and $57.40 per Bbl for oil for the 2009 disclosures, $6.36 per Mcf and $36.80 per Bbl for 2008 disclosures, and $7.59 per Mcf and $90.92 per Bbl for 2007 disclosures) at each date presented with no escalation. Future production and development costs are based on current costs without escalation. The resulting net future cash flows have been discounted to their present values based on a 10% annual discount factor.

Gas production from our deepwater and Permian Basin properties has a high BTU content of separator gas. The natural gas price $4.75 used in the 2009 reserve estimate reflects estimated revenues from our natural gas and associated natural gas liquids.

	Standardized Measure Years Ended December 31,		
	2009	2008	2007
		(In thousands)	
Future cash inflows	$ 462,607	$ 340,485	$3,113,759
Future costs -			
Production	(195,735)	(192,819)	(390,669)
Development and net abandonment	(50,170)	(34,111)	(405,186)
Future net inflows before income taxes	216,702	113,555	2,317,904
Future income taxes	(2,809)	(565)	(699,967)
Future net cash flows	213,893	112,990	1,617,937
10% discount factor	(77,972)	(26,685)	(483,948)
Standardized measure of discounted future net cash flows	$ 135,921	$ 86,305	$1,133,989

	Changes in Standardized Measure Years Ended December 31,		
	2009	2008	2007
		(In thousands)	
Standardized measure — beginning of period	$ 86,305	$ 1,133,989	$ 470,791
Sales and transfers, net of production costs	(82,674)	(122,104)	(142,973)
Net change in sales and transfer prices, net of production costs	94,435	(111,140)	411,525
Net change due to purchases and sales of in place reserves	45,009	(558,652)	795,595
Extensions, discoveries, and improved recovery, net of future production and development costs incurred	—	162,566	(201,750)
Changes in future development cost	6,194	33,652	—
Revisions of quantity estimates	39,242	(786,001)	(66,735)
Accretion of discount	5,797	159,147	53,474
Net change in income taxes	(2,368)	457,483	(393,530)
Changes in production rates, timing and other	(56,019)	(282,635)	207,592
Aggregate change	49,616	(1,047,684)	663,198
Standardized measure — end of period	$135,921	$ 86,305	$1,133,989

At year-end 2008, the Company had a reduction in reserves due to the sale to CIECO of a 50% interest in the Entrada field and the abandonment of the Entrada project.

The Company ended the year 2009 with estimated net proved reserves of 58.0 billion cubic feet of natural gas equivalent (“Bcfe”). This increase from 2008 year-end estimated net proved reserves of 54.8 Bcfe is primarily due to the ExL acquisition which closed October 28, 2009.

The Company annually reviews its proved undeveloped reserves (“PUDs”) to ensure an appropriate plan for development exists. Generally, reserves for the Company’s onshore properties are booked as PUDs only if the Company has plans to convert the PUDs into proved developed reserves within five years of the date they are first booked as PUDs. Callon had 19.6 Bcfe of PUDs at December 31, 2009, compared with 13.4 Bcfe of PUDs at December 31, 2008. Of these 2009 PUDs, 7.1 Bcfe and 6.9 Bcfe were attributable to the Company’s offshore properties in the Medusa and Habanero fields in the Gulf of Mexico, respectively. Callon plans are to develop these PUDs by side tracking existing wells when the zones currently being produced by the wells are depleted. The Company’s current reserve reports forecast that these producing zones in the Habenero field will be depleted in 2014 and in the Medusa field in 2022, at which time Callon plans to develop the PUDs. The Company did not convert any offshore PUDs to proved developed in 2009.

During 2009, the Company acquired 711 MBbls and 1.3 Bcf, or 5.6 Bcfe, of PUDs in its ExL acquisition. Callon’s development plan for these PUDs will begin in 2010 with an anticipated completion within five years, allowing the PUDs to be converted to PDPs. The remaining 0.6 Bcfe increase in PUDs from 2008 to 2009 is associated with the Company’s deepwater property, Medusa, and is a result of including reserves related to the Deepwater Royalty Relief Act. These PUDs were previously excluded due to prices exceeding the MMS imposed thresholds. As a result of court decisions, the MMS is no longer enforcing its price thresholds. At year end 2008, the Company had no PUDs located onshore. See Note 12.

19. SUMMARIZED QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(In thousands, except per share data)			
2009				
Total revenues	$24,815	$25,025	$21,320	$ 70,985 (a)
Income from operations	8,506	5,731	5,799	53,417 (a)
Net income (loss)	2,404	(925)	(955)	53,895 (b)
Net income (loss) per common share-basic	$ 0.11	$ (0.04)	$ (0.04)	$ 2.31
Net income (loss) per common share-diluted	0.11	(0.04)	(0.04)	2.27

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(In thousands, except per share data)			
2008				
Total revenues	$44,960	$48,029	$32,783	$ 15,540
Income (loss) from operations	21,069	24,046	13,640	(500,438) (c)
Net income (loss)	7,632	5,153	5,856	(457,534) (c)
Net income (loss) per common share-basic	$ 0.37	$ 0.25	$ 0.27	$ (21.19) (c)
Net income (loss) per common share-diluted	0.35	0.23	0.27	(21.19) (c)

(a) Includes Medusa royalty recoupment of $43.9 million, net of override, due from the MMS. See Note 12.

(b) Includes Medusa royalty recoupment of $43.9 million, net of override, and estimated interest in the amount of $7.7 million due from the MMS.

(c) Loss resulting from impairment of oil and gas properties in the amount of $485.5 million and establishing a full valuation allowance on the tax benefit in the amount of $128.1 million associated with net operating loss carryforwards as of December 31, 2009.

20. SUBSEQUENT EVENTS

Subsequent to December 31, 2009, the Company completed a $100 million third amended and restated senior secured credit agreement with Regions Bank as the sole arranger and administrative agent, which matures on September 25, 2012. The new senior secured credit agreement provides an initial borrowing base of $20 million, which will be reviewed and re-determined on a semi-annual basis. See Note 7.

In January 2010, Callon received a royalty refund of $44.8 million from the MMS on the royalties paid from November 2003 through August 2009 on the Medusa field. See Note 12.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

There have been no disagreements with the independent auditors on any matters of accounting principles or practices, financial statement disclosure, or auditing scope or procedures.

ITEM 9A. CONTROLS AND PROCEDURES

The term “disclosure controls and procedures” is defined in Rules 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934, or the Exchange Act. This term refers to the controls and procedures of a company that are designed to ensure that information required to be disclosed by a company in the reports that it files or submits under the Exchange Act is recorded, processed, summarized and reported within the time periods specified by the Securities and Exchange Commission. Our management, including our Chief Executive Officer and Chief Financial Officer, has evaluated the effectiveness of our disclosure controls and procedures as of the end of the period covered by this annual report. Based upon that evaluation, our Chief Executive Officer and Chief Financial Officer have concluded that our disclosure controls and procedures were effective as of the end of the period covered by this annual report. There were no changes to our internal control over financial reporting during our last fiscal quarter that have materially affected, or are reasonable likely to materially affect, our internal control over financial reporting.

Management’s Report On Internal Control Over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rules 13a-15(f). Under the supervision and with the participation of our management, including our principal executive and financial officers, we conducted an evaluation of the effectiveness of our internal control over financial reporting as of December 31, 2009 based on the frame work in the Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on our evaluation under the framework in Internal Control-Integrated Framework, our management concluded that our internal control over financial reporting was effective as of December 31, 2009.

Ernst & Young LLP, our independent registered public accounting firm, has issued an attestation report on the Company’s internal control over financial reporting as of December 31, 2009.

ITEM 9A (T). CONTROLS AND PROCEDURES

See Item 9A.

Report of Independent Registered Public Accounting Firm

The Board of Directors and Stockholders of
Callon Petroleum Company

We have audited Callon Petroleum Company's internal control over financial reporting as of December 31, 2009, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (the COSO criteria). Callon Petroleum Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

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 (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) 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 (3) 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.

In our opinion, Callon Petroleum Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2009, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Callon Petroleum Company as of December 31, 2009 and 2008, and the related consolidated statements of operations, stockholders' equity and cash flows for each of the three years in the period ended December 31, 2009 and our report dated March 12, 2010, expressed an unqualified opinion thereon.

/s/Ernst & Young LLP

New Orleans, Louisiana
March 12, 2010

ITEM 9B. OTHER INFORMATION

SUBMISSION OF MATTERS TO A VOTE OF THE SECURITY HOLDERS

The Company held a special meeting of shareholders on December 31, 2009. At the special meeting, the shareholders had two proposals to consider for vote.

Proposal I — The shareholders approved an amendment to article four of the Company's certificate of incorporation increasing the number of authorized shares of common stock of the Company from 30 million shares to 60 million shares.

Proposal II — The shareholders approved the issuance of common stock upon conversion of convertible preferred stock.

The votes cast for the amendments proposed in the Company's definitive proxy statement on Schedule 14A, out of a total of 25,598,743 shares outstanding on the record date for the special meeting was as follow:

	For	Against or Abstained
Proposal I	18,057,317	2,141,666
Proposal II	11,948,390	539,905

There were broker non-votes of 7,710,688 cast for Proposal I.

We have disclosed all information required to be disclosed in a current report on Form 8-K during the fourth quarter of the year ended December 31, 2009 in previously filed reports on Form 8-K.

PART III.

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

For information concerning Item 10, see the definitive proxy statement of Callon Petroleum Company relating to the Annual Meeting of Stockholders to be held on May 4, 2010 which will be filed with the Securities and Exchange Commission and is incorporated herein by reference.

The Company has adopted a code of ethics that applies to the Company's chief executive officer, chief financial officer and chief accounting officer. The full text of such code of ethics has been posted on the Company's website at www.callon.com, and is available free of charge in print to any shareholder who requests it. Request for copies should be addressed to the Secretary at 200 North Canal Street, Natchez, Mississippi 39120.

ITEM 11. EXECUTIVE COMPENSATION.

For information concerning Item 11, see the definitive proxy statement of Callon Petroleum Company relating to the Annual Meeting of Stockholders to be held on May 4, 2010 which will be filed with the Securities and Exchange Commission and is incorporated herein by reference.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS.

For information concerning the security ownership of certain beneficial owners and management, see the definitive proxy statement of Callon Petroleum Company relating to the Annual Meeting of Stockholders to be held on May 4, 2010 which will be filed with the Securities and Exchange Commission and is incorporated herein by reference.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS AND DIRECTOR INDEPENDENCE

For information concerning Item 13, see the definitive proxy statement of Callon Petroleum Company relating to the Annual Meeting of Stockholders to be held on May 4, 2010 which will be filed with the Securities and Exchange Commission and is incorporated herein by reference.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES.

For information concerning Item 14, see the definitive proxy statement of Callon Petroleum Company relating to the Annual Meeting of Stockholders to be held on May 4, 2010 which will be filed with the Securities and Exchange Commission and is incorporated herein by reference.

PART IV.

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a) 1. The following is an index to the financial statements and financial statement schedules that are filed as part of this Form 10-K on pages 49 through 83.

Report of Independent Registered Public Accounting Firm

Consolidated Balance Sheets as of the Years Ended December 31, 2009 and 2008

Consolidated Statements of Operations for the Three Years in the Period Ended December 31, 2009

Consolidated Statements of Stockholders' Equity for the Three Years in the Period Ended December 31, 2009

Consolidated Statements of Cash Flows for the Three Years in the Period Ended December 31, 2009

Notes to Consolidated Financial Statements

(a) 2. Schedules other than those listed above are omitted because they are not required, not applicable or the required information is included in the financial statements or notes thereto.

(a) 3. Exhibits:

2. Plan of acquisition, reorganization, arrangement, liquidation or succession*

3. Articles of Incorporation and Bylaws

   3.1 Certificate of Incorporation of the Company, as amended (incorporated by reference to Exhibit 3.1 of the Company's Annual Report on Form 10-K for the year ended December 31, 2003, File No. 001-14039)

   3.2 Bylaws of the Company (incorporated by reference from Exhibit 3.2 of the Company's Registration Statement on Form S-4, filed August 4, 1994, Reg. No. 33-82408)

   3.3 Certificate of Amendment to Certificate of Incorporation of the Company (incorporated by reference to Exhibit 3.3 of the Company's Annual Report on Form 10-K for the year ended December 31, 2003, File No. 001-14039)

   3.4 Certificate of Designations, Preferences and Rights of Convertible Preferred Stock of the Company (incorporated by reference to Appendix A of the Company's Definitive Proxy Statement on Schedule 14A, filed December 1, 2009, File No. 001-14039)

   3.5 Certificate of Correction to the Certificate of Designations, Preferences and Rights of Convertible Preferred Stock of the Company (incorporated by reference to Exhibit 3.1 of the Company's Current Report on Form 8-K, filed January 4, 2010, File No. 001-14039)

Table of Contents

4. Instruments defining the rights of security holders, including indentures

   4.1 Specimen Common Stock Certificate (incorporated by reference from Exhibit 4.1 of the Company's Registration Statement on Form S-4, filed August 4, 1994, Reg. No. 33-82408)

   4.2 Rights Agreement between Callon Petroleum Company and American Stock Transfer & Trust Company, Rights Agent, dated March 30, 2000 (incorporated by reference from Exhibit 99.1 of the Company's Registration Statement on Form 8-A, filed April 6, 2000, File No. 001-14039)

   4.3 Form of Warrants dated December 8, 2003 and December 29, 2003 entitling lenders under the Company's $185 million amended and restated senior unsecured credit agreement dated December 23, 2003 to purchase common stock from the Company (incorporated by reference to Exhibit 4.14 of the Company's Annual Report on Form 10-K for the year ended December 31, 2003, File No. 001-14039)

   4.4 Indenture for the Company's 9.75% Senior Notes due 2010, dated March 15, 2004 between Callon Petroleum Company and American Stock Transfer & Trust Company (incorporated by reference to Exhibit 4.16 of the Company's Quarterly Report on Form 10-Q for the period ended March 31, 2004, File No. 001-14039)

   4.5 Supplemental Indenture for the Company's 9.75% Senior Notes due 2010, dated April 4, 2008 (incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K, filed April 9, 2008, File No. 001-14039)

   4.6 Second Supplemental Indenture for the Company's 9.75% Senior Notes due 2010, dated November 24, 2009, between Callon Petroleum Company and American Stock Transfer & Trust Company

   4.7 Indenture for the Company's 13.00% Senior Notes due 2016, dated November 24, 2009, between Callon Petroleum Company, the subsidiary guarantors described therein, Regions Bank and American Stock Transfer & Trust Company (incorporated by reference to Exhibit T3C to the Company's Form T-3, filed November 19, 2009, File No. 022-28916)

9. Voting trust agreement

   None

10. Material contracts

   10.1 Callon Petroleum Company 1994 Stock Incentive Plan (incorporated by reference from Exhibit 10.5 of the Company's Registration Statement on Form 8-B, filed October 3, 1994)

   10.2 Callon Petroleum Company 1996 Stock Incentive Plan as amended on May 9, 2000 (incorporated by reference from Appendix I of the Company's Definitive Proxy Statement on Schedule 14A, filed March 28, 2000, File No. 001-14039)

   10.3 Callon Petroleum Company 2002 Stock Incentive Plan (incorporated by reference to Exhibit 10.13 of the Company's Annual Report on Form 10-K for the year ended December 31, 2001, File No. 001-14039)

10.4	Medusa Spar Agreement dated as of August 8, 2003, among Callon Petroleum Operating Company, Murphy Exploration & Production Company-USA and Oceaneering International, Inc. (incorporated by reference to Exhibit 10.19 of the Company's Annual Report on Form 10-K for the year ended December 31, 2003, File No. 001-14039)
10.5	Purchase and Sale Agreement between Callon Petroleum Company and Callon Petroleum Operating Company as Seller, and Indigo Minerals LLC, as Buyer (incorporated by reference from Exhibit 2.1 of the Company's Current Report on Form 8-K, filed December 13, 2007, File No. 001-14039)
10.6	Purchase and Sale Agreement by and between Callon Petroleum Operating Company and CIECO Energy (US) Limited (incorporated by reference from Exhibit 1.1 of the Company's Current Report on Form 8-K, filed February 13, 2008, File No. 001-14039)
10.7	Credit Agreement between Callon Entrada and CIECO Energy (Entrada) LLC dated April 4, 2008 (incorporated by reference to Exhibit 10.3 of the Company's Current Report on Form 8-K, filed April 9, 2008, File No. 001-14039)
10.8	Indemnity Agreement dated April 4, 2008 (incorporated by reference to Exhibit 10.4 of the Company's Current Report on Form 8-K, filed April 9, 2008, File No. 001-14039)
10.9	Non-Recourse Guaranty dated April 4, 2008 (incorporated by reference to Exhibit 10.5 of the Company's Current Report on Form 8-K, filed April 9, 2008, File No. 001-14039)
10.10	Severance Compensation Agreement dated April 18, 2008 by and between Fred L. Callon and Callon Petroleum Company (incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K, filed April 23, 2008, File No. 001-14039)
10.11	Form of Severance Compensation Agreement dated April 18, 2008 by and between Callon Petroleum Company and its executive officers (incorporated by reference to Exhibit 10.2 of the Company's Current Report on Form 8-K, filed April 23, 2008, File No. 001-14039)
10.12	Second Amended and Restated Credit Agreement dated as of September 25, 2008, by and among Callon Petroleum Company, the "Lenders" described therein, Regions Bank, as Syndication Agent, Capital One, N.A., as Documentation Agent, and Union Bank of California, N.A., as Administrative Agent (incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K, filed October 1, 2008, File No. 001-14039)
10.13	Amendment No. 1 to Severance Compensation Agreement executed on December 31, 2008 by and between Fred L. Callon and Callon Petroleum Company (incorporated by reference from Exhibit 10.1 of the Company's Current Report on Form 8-K, filed January 5, 2009, File No. 001-14039)
10.14	Form of Amendment No. 1 to Severance Compensation Agreement by and between Callon Petroleum Company and its executive officers (incorporated by reference from Exhibit 10.2 of the Company's Current Report on Form 8-K, filed January 5, 2009, File No. 001-14039)
10.15	Amendment No. 3 to the Callon Petroleum Company 1996 Stock Incentive Plan (incorporated by reference from Exhibit 10.1 of the Company's Current Report on Form 8-K, filed January 5, 2009, File No. 001-14039)

10.16 Amendment No. 1 to the Callon Petroleum Company 2002 Stock Incentive Plan (incorporated by reference from Exhibit 10.2 of the Company's Current Report on Form 8-K, filed January 5, 2009, File No. 001-14039)

10.17 Callon Petroleum Company Amended and Restated 2006 Stock Incentive Plan (incorporated by reference from Exhibit 10.3 of the Company's Current Report on Form 8-K, filed January 5, 2009, File No. 001-14039)

10.18 Amendment No. 1 dated as of March 19, 2009 to the Second Amended and Restated Credit Agreement dated September 25, 2008, among Callon Petroleum Company, the "Lenders" described therein and Union Bank of California, N.A., as Administrative Agent and as Issuing Lender (incorporated by reference from Exhibit 10.25 to the Company's Annual Report on Form 10-K for the year ended December 31, 2008, File No. 001-14039)

10.19 Callon Petroleum Company 2009 Stock Incentive Plan effective as of April 30, 2009 (incorporated by reference from Exhibit A to the Company's Definitive Proxy Statement on Schedule 14A, filed March 30, 2009, File No. 001-14039)

10.20 Callon Petroleum Company Nonqualified Stock Option Award Agreement, dated June 1, 2009, between Callon Petroleum Company and Steven B. Hinchman (incorporated by reference from Exhibit 10.1 of the Company's Quarterly Report on Form 10-Q for the period ended June 30, 2009, File No. 001-14039)

10.21 Callon Petroleum Company Performance Share Award Agreement, dated June 1, 2009, between Callon Petroleum Company and Steven B. Hinchman (incorporated by reference from Exhibit 10.2 of the Company's Quarterly Report on Form 10-Q for the period ended June 30, 2009, File No. 001-14039)

10.22 Amendment to the Callon Petroleum Company 1996 Stock Incentive Plan effective as of August 7, 2009 (incorporated by reference from Exhibit 10.1 of the Company's Quarterly Report on Form 10-Q for the period ended September 30, 2009, File No. 001-14039)

10.23 Purchase and Sale Agreement by and between Callon Petroleum Operating Company and Ambrose Energy I, Ltd. dated September 9, 2009 (incorporated by reference to Exhibit 2.1 of the Company's Current Report on Form 8-K, filed September 11, 2009, File No. 001-14039)

10.24 Amendment No. 3 and Agreement dated as of October 16, 2009 to the Second Amended and Restated Credit Agreement dated September 25, 2008, among Callon Petroleum Company, the "Lenders" described therein, and Union Bank, N.A., as Administrative Agent and as Issuing Lender (incorporated by reference to Exhibit 2.1 of the Company's Current Report on Form 8-K, filed October 22, 2010, File No. 001-14039)

10.25 Third Amended and Restated Credit Agreement dated January 29, 2010, by and among Callon Petroleum Company, the "Lenders" described therein, Regions Bank, as Administrative Agent, Documentation Agent and Syndication Agent (incorporated by reference from Exhibit 10.1 of the Company's Current Report on Form 8-K, filed February 3, 2010, File No. 001-14039)

11. Statement re computation of per share earnings*

12. Statements re computation of ratios*

13. Annual Report to security holders, Form 10-Q or quarterly reports*

14. Code of Ethics

14.1 Code of Ethics for Chief Executive Officers and Senior Financial Officers (incorporated by reference to Exhibit 14.1 of the Company's Annual Report on Form 10-K for the year ended December 31, 2003, File No. 001-14039)

16. Letter re change in certifying accountant*

18. Letter re change in accounting principles*

21. Subsidiaries of the Company

21.1 Subsidiaries of the Company (incorporated by reference from Exhibit 21.1 of the Company's Registration Statement on Form 8-B filed October 3, 1994)

22. Published report regarding matters submitted to vote of security holders*

23. Consents of experts and counsel

23.1 Consent of Ernst & Young LLP

23.3 Consent of Huddleston & Co., Inc.

24. Power of attorney*

31. Rule 13a-14(a) Certifications

31.1 Certification of Chief Executive Officer pursuant to Rule 13(a)-14(a)

31.2 Certification of Chief Financial Officer pursuant to Rule 13(a)-14(a)

32. Section 1350 Certifications

32.1 Certification of Chief Executive Officer pursuant to Rule 13(a)-14(b)

32.2 Certification of Chief Financial Officer pursuant to Rule 13(a)-14(b)

99. Additional Exhibits

99.1 Reserve Report Summary prepared by Huddleston and Co. as of December 31, 2009.

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* Inapplicable to this filing.

SIGNATURES

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 capacities and on the dates indicated.

CALLON PETROLEUM COMPANY

Date: March 12, 2010	/s/ Fred L. Callon Fred L. Callon (principal executive officer, director)
Date: March 12, 2010	/s/ B. F. Weatherly B. F. Weatherly (principal financial officer, director)
Date: March 12, 2010	/s/ Rodger W. Smith Rodger W. Smith (principal accounting officer)
Date: March 12, 2010	/s/ L. Richard Flury Richard Flury (director)
Date: March 12, 2010	/s/ John C. Wallace John C. Wallace (director)
Date: March 12, 2010	/s/ Richard O. Wilson Richard O. Wilson (director)
Date: March 12, 2010	/s/ Larry D. McVay Larry McVay (director)

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.

CALLON PETROLEUM COMPANY

Date: March 12, 2010

By: /s/ B. F. Weatherly
B. F. Weatherly, Executive Vice-President and
Chief Financial Officer

Exhibit 4.6

SECOND SUPPLEMENTAL INDENTURE

SECOND SUPPLEMENTAL INDENTURE dated as of November 24, 2009 (the ***"Supplemental Indenture"***), between CALLON PETROLEUM COMPANY, a Delaware corporation (the ***"Company"***), having its principal office at 200 North Canal Street, Natchez, Mississippi 39120, the undersigned Subsidiary Guarantors (herein so called), and AMERICAN STOCK TRANSFER & TRUST COMPANY, LLC, as trustee (the ***"Trustee"***).

WHEREAS, there has heretofore been executed and delivered to the Trustee an Indenture dated as of March 15, 2004 between the Company, the Subsidiary Guarantors and the Trustee (as the same may have been amended or supplemented from time to time by one or more indentures supplemental thereto entered into pursuant to the applicable provisions thereof, the ***"Indenture"***), providing for the issuance of the Company's 9.75% Senior Notes due 2010, Series B (the ***"Securities"*** or the ***"Notes"***);

WHEREAS, the Company originally issued $200,000,000 in aggregate principal amount of the Notes pursuant to the Indenture;

WHEREAS, Section 9.2 of the Indenture provides that the Company, the Subsidiary Guarantors and the Trustee may amend certain terms and provisions of the Indenture or the Notes with the written consent of the Holders of at least seventy-five percent (75%) in aggregate principal amount of the Notes then outstanding;

WHEREAS, the Company has offered (the ***"Offer"***) to exchange any and all of the outstanding Notes for certain new notes and capital stock issued by the Company upon the terms and subject to the conditions set forth in the Offer to Exchange and Consent Solicitation Statement, dated October 20, 2009 (as the same may be amended or supplemented from time to time), from each Holder of the Notes;

WHEREAS, the Offer is conditioned upon, among other things, certain amendments to the Indenture and to the Notes set forth in Article One, Article Two and Article Three of this Supplemental Indenture (the ***"Amendments"***) having been approved by Holders of at least 75% in aggregate principal amount of the outstanding Notes (and a supplemental indenture in respect thereof having been executed and delivered), provided that the Amendments will not become operative until Notes have been accepted for exchange pursuant to the Offer;

WHEREAS, the Company has received and delivered to the Trustee the consents from Holders of at least 75% in aggregate principal amount of the outstanding Notes (***"Consenting Holders"***) to effect the Amendments; and

WHEREAS, all acts, conditions, proceedings and requirements necessary to make this Supplemental Indenture a valid, binding and legal agreement enforceable in accordance with its terms for the purposes expressed herein, in accordance with its terms, have been duly done and performed;

NOW THEREFORE, this Supplemental Indenture witnesseth that, for and in consideration of the premises, the Company and the Trustee agree as follows for the equal and ratable benefit of the Holders of the Securities:

ARTICLE I
EFFECTIVENESS

SECTION 1.1. *Effectiveness.* This Supplemental Indenture shall become effective as of the date hereof.

ARTICLE II
AMENDMENTS TO INDENTURE

SECTION 2.1. *Amendments to Indenture.*

(a) The Table of Contents of the Indenture is amended by deleting the titles to Sections 3.1 — 3.13, 3.16 — 3.25 and 4.1 and inserting in lieu thereof in each place the phrase "[intentionally omitted]".

(b) Sections 1.1 and 1.2 of the Indenture are amended by deleting all definitions of terms, and references to definitions of terms, that are used exclusively in the text of the Indenture and/or the Notes that are being eliminated by this Supplemental Indenture.

(c) Sections 3.1 — 3.13 of the Indenture are amended by deleting the text of each such Section in its entirety and inserting in lieu thereof the phrase "[intentionally omitted]".

(d) Section 3.14(a) of the Indenture is amended by deleting the text of such Section in its entirety and inserting in lieu thereof the phrase "[intentionally omitted]".

(e) Sections 3.16 — 3.25 of the Indenture are amended by deleting the text of each such Section in its entirety and inserting in lieu thereof the phrase "[intentionally omitted]".

(f) Section 4.1 of the Indenture is amended by deleting the text of such Section in its entirety and inserting in lieu thereof the phrase "[intentionally omitted]".

(g) Section 6.1(b) of the Indenture is amended by deleting the text of such Section in its entirety and inserting in lieu thereof the phrase "[intentionally omitted]".

(h) Section 6.1(c)(i) of the Indenture is amended by deleting the text of such Section in its entirety and inserting in lieu thereof the phrase "[intentionally omitted]".

(i) Section 6.1(d) of the Indenture is amended by deleting the text of such Section in its entirety and inserting in lieu thereof the phrase "[intentionally omitted]".

(j) Section 6.1(e) of the Indenture is amended by deleting the text of such Section in its entirety and inserting in lieu thereof the phrase "[intentionally omitted]".

(k) Section 6.1(f) of the Indenture is amended by deleting the text of such Section in its entirety and inserting in lieu thereof the phrase "[intentionally omitted]".

(l) Section 6.1(g) of the Indenture is amended by deleting the text of such Section in its entirety and inserting in lieu thereof the phrase "[intentionally omitted]".

(m) Section 6.1(h) of the Indenture is amended by deleting the text of such Section in its entirety and inserting in lieu thereof the phrase "[intentionally omitted]".

(n) Sections 10.1 — 10.4 of the Indenture are amended by deleting the text of each such Section in its entirety and inserting in lieu thereof the phrase "[intentionally omitted]", and as of the date hereof and after giving effect to this Supplemental Indenture, the parties signing below as Subsidiary Guarantors shall be released and discharged from any obligations and indebtedness under the Indenture, including any guarantee of the Obligations (as defined in the Indenture) and shall no longer be or be deemed to be parties to the Indenture.

ARTICLE III
MISCELLANEOUS

SECTION 3.1 *Elimination of Certain Provisions in the Notes*.

The Notes are deemed to be amended as follows:

(a) Section 4 of the Notes is amended by deleting the text of the last paragraph of such Section; and

(b) Subsections (b), (c)(i), and (d) — (h) of Section 12 of the Notes are amended by deleting the text of each such subsection in its entirety and inserting in lieu thereof the phrase "[intentionally omitted]".

ARTICLE IV
MISCELLANEOUS

SECTION 4.1 *Instruments To Be Read Together.* This Supplemental Indenture is an indenture supplemental to and in implementation of the Indenture, and said Indenture and this Supplemental Indenture shall henceforth be read together.

SECTION 4.2 *Confirmation.* The Indenture as amended and supplemented by this Supplemental Indenture is in all respects confirmed and preserved.

SECTION 4.3 *Terms Defined.* Capitalized terms used in this Supplemental Indenture and not otherwise defined herein shall have the respective meanings set forth in the Indenture.

SECTION 4.4 *Headings.* The headings of the Articles and Sections of this Supplemental Indenture have been inserted for convenience of reference only, and are not to be considered a part hereof and shall in no way modify or restrict any of the terms and provisions hereof.

SECTION 4.5 *Governing Laws.* This Supplemental Indenture shall be governed by, and construed in accordance with, the laws of the State of New York.

SECTION 4.6 *Multiple Originals.* The parties may sign any number of copies of this Supplemental Indenture. Each signed copy shall be an original, but all of them together represent the same agreement. One signed copy is enough to prove this Supplemental Indenture.

SECTION 4.7 *Compliance with the Trust Indenture Act*. This Supplemental Indenture shall be interpreted to comply in every respect with the Trust Indenture Act of 1939, as amended (the ***"TIA"***). If any provision of this Supplemental Indenture limits, qualifies or conflicts with the duties imposed by the TIA, the imposed duties shall control.

SECTION 4.8 *Responsibility of Trustee.* The recitals contained herein shall be taken as the statements of the Company, and the Trustee assumes no responsibility for their correctness. The Trustee makes no representations as to the validity or sufficiency of this Supplemental Indenture, except that the Trustee is duly authorized to execute and deliver this Supplemental Indenture.

[Signature Page Follows]

IN WITNESS WHEREOF, the parties hereto have caused this Second Supplemental Indenture to be duly executed, all as of the date first written above.

CALLON PETROLEUM COMPANY

By: /s/ B. F. Weatherly
Name: B. F. Weatherly
Title: Executive Vice President and Chief Financial Officer

Subsidiary Guarantors:
CALLON PETROLEUM OPERATING COMPANY

By: /s/ B. F. Weatherly
Name: B. F. Weatherly
Title: Executive Vice President and Chief Financial Officer

CALLON OFFSHORE PRODUCTION, INC.

By: /s/ B. F. Weatherly
Name: B. F. Weatherly
Title: Executive Vice President and Chief Financial Officer

MISSISSIPPI MARKETING, INC.

By: /s/ B. F. Weatherly
Name: B. F. Weatherly
Title: Executive Vice President and Chief Financial Officer

AMERICAN STOCK TRANSFER & TRUST COMPANY, LLC, as Trustee

By: /s/ HERBERT J. LEMMER
Name: HERBERT J. LEMMER
Title: VICE PRESIDENT

[Signature Page — Second Supplemental Indenture]

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in the following Registration Statements:

Registration Statement (Form S-8 No. 33-90410) of Callon Petroleum Company;
Registration Statement (Form S-8 No. 333-100646) of Callon Petroleum Company;
Registration Statement (Form S-3 No. 333-87945) of Callon Petroleum Company;
Registration Statement (Form S-3 No. 333-60606) of Callon Petroleum Company;
Registration Statement (Form S-8 No. 333-47784) of Callon Petroleum Company;
Registration Statement (Form S-8 No. 333-29537) of Callon Petroleum Company;
Registration Statement (Form S-8 No. 333-29529) of Callon Petroleum Company;
Registration Statement (Form S-8 No. 333-109744) of Callon Petroleum Company;
Registration Statement (Form S-8 No. 333-135703) of Callon Petroleum Company;
Registration Statement (Form S-3 No. 333-148680) of Callon Petroleum Company;

of our reports dated March 12, 2010, with respect to the consolidated financial statements of Callon Petroleum Company and the effectiveness of internal control over financial reporting of Callon Petroleum Company, included in this Annual Report (Form 10-K) for the year ended December 31, 2009.

/s/Ernst & Young LLP

New Orleans, Louisiana
March 12, 2010

EXHIBIT 23.3

CONSENT OF HUDDLESTON & CO., INC.

As independent oil and gas consultants, we hereby consent to the references to us and our reserve reports for the years ended December 31, 2009, 2008, and 2007 in Callon Petroleum Company's Annual Report on Form 10-K for the year ended December 31, 2009, which is incorporated by reference in this Registration Statement on Form S-3. We consent to the incorporation by reference in this Registration Statement of the aforementioned report and to the use of our name as it appears under the caption "Experts."

HUDDLESTON & CO., INC.
Texas Registered Engineering Firm F-1024

/s/ Peter D. Huddleston

Peter D. Huddleston, P.E.
President

Houston, Texas
March 11, 2010

Exhibit 31.1

CERTIFICATIONS

I, Fred L. Callon, certify that:

1. I have reviewed this Annual Report on Form 10-K of Callon Petroleum Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent function):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls over financial reporting;

Date: March 12, 2010

By: /s/ Fred L. Callon
Fred L. Callon, President and Chief Executive Officer
(Principal Executive Officer)

Exhibit 31.2

CERTIFICATIONS

I, B. F. Weatherly, certify that:

1. I have reviewed this Annual Report on Form 10-K of Callon Petroleum Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent function):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls over financial reporting;

Date: March 12, 2010

By: /s/ B. F. Weatherly

B. F. Weatherly, Executive Vice-President and
Chief Financial Officer (Principal Financial Officer)

EXHIBIT 32.1

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350

In connection with the Annual Report of Callon Petroleum Company (the "***Company***") on Form 10-K for the fiscal year ended December 31, 2009, as filed with the Securities and Exchange Commission on the date hereof (the "***Report***"), I, Fred L. Callon, Chief Executive Officer of the Company, certify, pursuant to 18 U.S.C. § 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to my knowledge:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company as of, and for the periods presented in the Report.

Dated: March 12, 2010

/s/ Fred L. Callon
Fred L. Callon, Chief Executive Officer (Principal Executive Officer)

The foregoing certification is being furnished as an exhibit to the Report pursuant to Item 601(b)(32) of Regulation S-K and Section 906 of the Sarbanes-Oxley Act of 2002 (subsections (a) and (b) of Section 1350, Chapter 63 of Title 18, United States Code) and, accordingly, is not being filed as part of the Report for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, and is not incorporated by reference into any filing of the Company, whether made before or after the date hereof, regardless of any general incorporation language in such filing.

EXHIBIT 32.2

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350

In connection with the Annual Report of Callon Petroleum Company (the "***Company***") on Form 10-K for the fiscal year ended December 31, 2009, as filed with the Securities and Exchange Commission on the date hereof (the "***Report***"), I, B. F. Weatherly, Chief Financial Officer of the Company, certify, pursuant to 18 U.S.C. § 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to my knowledge:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company as of, and for the periods presented in the Report.

Dated: March 12, 2010

/s/ B. F. Weatherly
B. F. Weatherly, Chief Financial Officer (Principal Financial Officer)

The foregoing certification is being furnished as an exhibit to the Report pursuant to Item 601(b)(32) of Regulation S-K and Section 906 of the Sarbanes-Oxley Act of 2002 (subsections (a) and (b) of Section 1350, Chapter 63 of Title 18, United States Code) and, accordingly, is not being filed as part of the Report for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, and is not incorporated by reference into any filing of the Company, whether made before or after the date hereof, regardless of any general incorporation language in such filing.

Exhibit 99.1

Huddleston & Co., Inc.
Petroleum and Geological Engineers
1 Houston Center
1221 McKinney, Suite 3700
Houston, Texas 77010

PHONE (713) 209-1100 ◆ FAX (713) 752-0828

February 24, 2010

Callon Petroleum Company
200 North Canal Street
Natchez, Mississippi 39120

Re: Callon Petroleum Company
Estimated Future Reserves and Revenues
As of December 31, 2009

Gentlemen:

Pursuant to your request, we have estimated oil, condensate, and natural gas reserves and projected revenues for properties owned by Callon Petroleum Company. The properties are located in Louisiana, Texas, and in the federal waters of the Gulf of Mexico.

Our conclusions, as of December 31, 2009, follow:

	Net To Callon Petroleum Company*			
	Proved Developed		Proved	Total
Constant Product Prices	Producing	Nonproducing	Undeveloped	Proved
Estimated Future Net Oil/Cond., Mbbl	2,100.3	2,245.6	2,132.8	6,478.7
Estimated Future Net (Sales) Gas, MMcf	9,322.1	2,979.2	6,801.3	19,102.6
Estimated Future Gross Revenue, $M	161,007.7	141,926.0	159,674.7	462,608.4
Estimated Future Operating Expenses, $M	56,239.3	76,741.2	25,502.8	158,483.3
Estimated Future Production Taxes, $M	2,855.1	142.3	2,531.0	5,528.3
Estimated Future Capital Costs, $M	16,469.4	16,133.6	49,291.3	81,894.3
Estimated Future Net Revenue (“FNR”), $M	85,443.9	48,908.9	82,349.6	216,702.5
Estimated FNR Discounted at 10%, $M	69,831.8	42,948.1	24,588.0	137,367.9
Projected Revenues by Year — Constant Product Prices, $M**				
2010	43,696.1	(2,495.4)	(14,971.4)	26,229.4
2011	24,731.6	1,117.2	3,186.5	29,035.3
2012	7,070.0	11,127.7	3,894.7	22,092.4
Thereafter	9,946.2	39,159.4	90,239.8	139,345.4
Total	85,443.9	48,908.9	82,349.6	216,702.5
Estimated 2010 Production				
Oil/Cond., Mbbl	759.9	6.5	51.6	818.1
Gas (Sales), MMcf	4,592.4	324.9	44.8	4,962.1

* Numbers subject to rounding.

** Certain negative values are attributable to operating cost allocation for the producing and nonproducing categories.

Report Preparation

Purpose of Report — The purpose of this report is to provide the management of Callon with a projection of future reserves and revenues for an assessment of oil and gas properties owned by Callon. The Proved reserve and revenue projections shown herein have been prepared in accordance with Securities and Exchange Commission ("SEC") requirements for reporting purposes as described below. Although we have prepared projections of Probable and Possible reserves, it is our understanding that Callon has elected to exclude such reserve volumes for public reporting purposes.

Reporting Requirements — SEC Regulation S-K, Item 102, and Regulation S-X, Rule 4-10, require oil and gas reserve information to be reported by publicly held companies as supplemental financial data. These regulations were revised by the SEC effective for filings beginning January 1, 2010. The revised regulations provide for certain changes in Proved reserve definitions, add definitions for Probable and Possible reserves, and require that revenues associated with Proved reserves be reported on the basis of the average of the preceding 12-month, first-of-month product prices. Revenues are to be discounted at 10%, consistent with that required in prior years.

The Proved reserves included herein under "Constant Product Prices" have been prepared in accordance with our understanding of the methodologies specified under SEC and Financial Accounting Standards Board guidelines.

Standards of Practice — This report has been prepared in accordance with our understanding of the *Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserve Information* as promulgated by the Society of Petroleum Engineers and the *Guidelines for Application of the Definitions for Oil and Gas Reserves* prepared by the Society of Petroleum Evaluation Engineers. However, the projected reserves have been prepared with consideration for reserve classification definitions specified by the SEC that do not necessarily conform to definitions promulgated by the Society of Petroleum Engineers and the World Petroleum Congress.

Definitions for reserves as outlined in SEC Regulation S-X, Rule 4-10 are included herein.

Economic Limits — In some cases the projections have been prepared with consideration for overall field production, resulting in negative cash flow projections for certain properties. In our opinion, the projections shown herein properly reflect the expected operations. The projections for some properties include consideration for abandonment costs, resulting in negative future revenues and discounted revenues.

Cash Flow Projections — The cash flow projections were run on the aries computer program utilizing Callon's computer facilities. However, Huddleston & Co., Inc., supplied all of the input parameters for the reserve projections.

The attached cash flow projections have been sorted by reserve classification, then state, field, and lease. Properties located in federal waters have been grouped as "Gulf Federal".

Cash Flow Presentation — The gross and net reserve volume columns in the cash flow projections have been separated into three different columns: oil (Mbbl), produced gas (MMcf), and sales gas (MMcf). Product prices, net revenues before taxes, and severance taxes are shown separately for each product.

Reserve Estimates

Extrapolation of performance history and material balance estimates were utilized for projecting future recoverable reserves for the producing properties where sufficient history was available to suggest performance trends and where these methods were applicable to the subject reservoirs. The projections for the remaining producing properties were necessarily based on volumetric calculations and/or analogy to nearby producing completions. Reserves assigned to nonproducing zones and undeveloped locations were projected on the basis of volumetric calculations and analogy to nearby production.

Approximately 51% of the future net revenues discounted at 10% are included in the Proved Developed Producing category. The remaining 49% of discounted net revenues are included in the Nonproducing and Undeveloped classifications. Reserve estimates for those properties in the Nonproducing and Undeveloped categories will be subject to a significantly greater level of variation than estimates for producing properties exhibiting established decline trends.

We have utilized certain geologic and engineering data furnished by Callon. However, in all cases we have exercised the final judgments for the estimated reserves and future schedules of production.

Gas Volumes — Gas volumes are reported at the prevailing pressure base of the state in which the reserves are located and at 60 degrees Fahrenheit. The projections reflect gas streams for production gas and sales gas. The difference between the two is intended to reflect fuel and lease usage.

Property Descriptions

Mississippi Canyon 538/582 — The Medusa Prospect, drilled by Murphy on Mississippi Canyon Blocks 538 and 582 during 1999 and more fully delineated as a result of drilling conducted in 2000 and 2001, successfully tested a number of horizons in two separate fault blocks. Drilling operations conducted during 2002 resulted in certain minor revisions in geological interpretations and reserves were adjusted to reflect a revised study of geological and petrophysical characteristics. Reserve estimates for a total of 17 reservoirs, representing 11 horizons, have been based on volumetric calculations utilizing 3-D seismic data and subsurface control for mapping, as well as petrophysical calculations derived from well logs and sidewall cores.

Production operations for this property were initiated in November 2003 and there were 8 wellbores producing at the time of report preparation. The estimated reserves for those reservoirs completed in the existing wells have been revised from our original projections to reflect the performance of the wells to date. In some cases Nonproducing and Undeveloped reserve assignments have been adjusted to conform with the performance of the existing completions. On an overall basis the estimated ultimate oil reserves have been decreased 3.3% and gas reserves have been increased 6.6% in comparison to our previous report. The Medusa Prospect represents 68.1% and 17.1% of the oil and gas, respectively, net to Callon.

Undeveloped reserves projected for a sidetrack of the A-1 wellbore are scheduled to be developed upon depletion of reserves assigned to the existing well. We have been informed that the scheduling of development operations is the result of facilities limitations and cost considerations associated with drilling a separate wellbore.

Garden Banks 341 — The Habanero Prospect drilled by Shell during the first half of 1999 encountered two productive horizons: the Habanero 52 oil sand and the Habanero 55 gas sand. The productive horizons were also tested in a downdip, nonproductive sidetrack that allows for the calculation of hydrocarbon limits in both horizons. Proved reserves were assigned on the basis of information derived from the two wellbores and supported by seismic interpretations. Additional drilling activities conducted during 2001 resulted in establishing the updip productive limits in both reservoirs and established a separate productive fault block in the Habanero 52 gas sand.

After being sidetracked to its current location in May 2003, production operations were initiated during November 2003 with the No. 2 well being completed in the Habanero 52 sand at a rate of 12,000 BOPD and 19 MMcf/day. In addition, the No. 1 was tested at a rate of 4,700 BOPD and 8.3 MMcf/day; however, the sliding sleeve separating the Habanero 52 and 55 sands was found to be in the open position resulting in the co-mingling of the two zones. A subsequent workover in the No. 1 wellbore resulted in a single completion in the Habanero 52 sand. We have been informed that the Habanero 55 sand is no longer mechanically able to be produced in the No. 1 well and the reserves for this horizon have been eliminated from our report.

The estimated reserves shown herein include consideration for two producing completions in the Habanero 52 oil sand, and two sidetrack locations to produce the Habanero 52 gas sand. Projected ultimate oil recoveries are unchanged and gas recoveries have been revised upward 3.2% to reflect well performance.

The undeveloped reserves for this property have been included in our projected reserves since 2001 and currently are scheduled to be developed at the depletion of the existing completions in 2014. We have been informed that it is the intention of the operator to sidetrack the existing wellbores to exploit these reserves. The timing of such operations is the result of physical facilities limitations and economic considerations with respect to both drilling operations for new wellbores and reconfiguration of the facilities.

On an overall basis the estimated reserves attributable to the Habanero Prospect represent 11.2% of the estimated Proved net oil and 24.8% of the Proved net gas for Callon. Approximately 60% of the oil reserves and 91% of the gas reserves for this property have been included in the Undeveloped category.

Wolfberry Properties — In 2009 Callon acquired ownership in four West Texas fields: Block 5, Carpe Diem, East Bloxum, and Kayleigh, located in Crockett, Midland, Upton, and Ector Counties, respectively. The subject properties are located within the Wolfberry trend. On an overall basis the properties include 22 producing wells and 17 undeveloped locations.

Reserve assignments for the producing completions were assigned on the basis of the extrapolation of performance data. Analogy was considered in determining hyperbolic exponents for the estimation of future reserves for those completions that did not have sufficient production history to definitively project the proper decline profile. Reserves for the undeveloped locations were projected on the basis of analogy to existing completions. In all cases, the undeveloped locations are direct offsets to existing completions.

In aggregate, these properties represent 19.1% and 11.0% of oil and gas reserves, respectively, net to Callon. Approximately 58% of the estimated reserves, on an equivalent barrel basis, are in the undeveloped category. We have been informed by Callon that development operations are to be commenced on the properties in 2010.

West Cameron Block 295 — West Cameron Block 295, discovered in 2005, is defined by two separate gas accumulations that are productive from similar geologic intervals. However, there is some evidence that the M-1 sands in the two existing wells have some degree of pressure communication though produced fluids vary somewhat in composition. The No. A-1 (formerly No. 2) wellbore encountered productive sands in the Rob M-1 horizon (15,370’ MD) and the Rob L horizon (13,100’ MD). The well was completed in the Rob M-1 and is currently on production with the Rob L behind-pipe. A development well, designed to effectively drain the M-1 reservoir (No. A-2), was drilled during 2006 and encountered the target horizon. The initial completion in the Rob M-1 Lower depleted during 2007 and the well has been recompleted to the Rob M-1.

The previous reserve assignments included a behind-pipe recompletion in the Rob L sand in the A-1 wellbore. However, this zone is no longer included in the Proved category as a result of mechanical concerns associated with recompletion operations.

Reserve estimates for the property were increased to reflect the performance of the existing completions. Ultimate gross recovery for the field is estimated to be approximately 28.5 Bcf. The property represents 9.0% of remaining gas reserves net to Callon.

Product Prices

As we understand the SEC requirements issued on January 14, 2009, oil and gas prices utilized to determine the Standardized Measure of discounted cash flows should be based on the trailing twelve-month average of the first-of-the-month prices. The estimated revenues shown herein reflect the actual average of first-of-the-month prices received by Callon on a property by property basis. The projected prices for both oil and gas were based on our understanding of SEC requirements. It is noted that the pricing requirements vary significantly from those previously required for reporting purposes.

Gas prices have been adjusted to reflect the Btu content, transportation charges, and other fees specific to the individual properties. Gas prices for certain properties include consideration for processing arrangements and the price shown herein has been adjusted to reflect such arrangements in comparison to produced gas volumes. On an overall basis, the wellhead gas prices utilized herein are approximately 25% less than the values utilized as of December 31, 2008. In some cases the reduced prices may have resulted in marginally lower levels of economically recoverable gas. Market level gas prices are subject to a significant level of variation depending on location and marketing considerations specific to the individual properties. In our opinion, it is likely that there will be a substantial degree of variation in prices in the future. Spot prices for natural gas have experienced a large degree of volatility during recent years, which can be attributed to seasonal demands and other market considerations.

The projected oil prices for individual properties have been adjusted to reflect all wellhead deductions and premiums on a property by property basis, including transportation costs, location differentials, and crude quality. The weighted average wellhead prices shown herein are approximately 56% less than those utilized for our report prepared as of December 31, 2008, which has had a material impact on estimated future revenues and in some cases has marginally affected economically recoverable reserves. Variations in oil prices are the result of changes in market conditions and future prices are likely to be affected by a variety of factors including OPEC actions, political and market considerations, and overall economic conditions.

All deductions and premiums to individual oil and gas prices were held constant over the life of the properties. Variations in future product prices may materially affect actual revenues in comparison to the projections shown herein.

Product price hedges, if any, were not considered for the purposes of this report.

A comparison of the average product prices, weighted as a composite for all Proved properties, follows:

	2010	Maximum	Average Over Life
Oil, $/bbl	57.43	57.74	57.40
Gas, $/Mcf	4.15	6.48	4.75

Operating Expenses

Operating expenses, generally shown as dollars per well per month for onshore properties, were provided by Callon and adjusted for nonrecurring costs where applicable. In some cases, particularly for the offshore properties, operating costs were projected on a total-unit or platform basis and the projections were continued until the unit or facility reached the economic limit. Severance and ad valorem taxes were calculated at the rates applicable to each property and have been deducted from the cash flow. Operating costs were held constant over the economic life of the properties.

Capital Costs

Capital costs necessary to perform recompletions and to drill new wells were supplied by Callon. We have generally reviewed the projected expenditures and they are consistent with our perception of current costs necessary to perform the intended operations. Capital costs were held constant over the life of the properties.

Other Considerations

Additional Costs — Costs were not deducted for depletion, depreciation, and/or amortization. Consideration has also been excluded for federal and/or state income taxes, if any.

Abandonment costs for all offshore properties and certain onshore properties were included in the projections where Callon has determined the total cost associated with abandoning the facilities and platforms will exceed salvage value. In some cases, funds have been escrowed to cover anticipated future abandonment costs. The projections reflect a total of $31,723,660 in abandonment costs.

Additional Potential Values — Values were not assigned to nonproducing acreage or to acreage held by production, if any. In general, the salvage of surface and subsurface equipment for the onshore properties was assumed to be equal to abandonment costs.

Context — The estimated reserves and revenues shown herein should be considered on an overall basis and estimates for individual properties should not be taken out of context with the total or overall projections.

THE REVENUES AND PRESENT WORTH OF FUTURE NET REVENUES ARE NOT REPRESENTED TO BE MARKET VALUES EITHER FOR INDIVIDUAL PROPERTIES OR ON A TOTAL PROPERTY BASIS.

Data Sources — Essentially all data were furnished by Callon, including production statistics, product prices, operating costs, ownership, and basic well information. We have accepted the data as represented. We express no opinions and make no representations as to legal or accounting interpretations provided by Callon. Production statistics for the significant Callon-operated properties and for several of the other more significant properties were available through December 2009.

We retain in our files plotted production histories for all properties and certain other information that we believe pertinent. We have not inspected the properties evaluated in this report nor have we conducted independent well tests.

Respectfully submitted,

Peter D. Huddleston, P.E.
Texas Registered Engineering Firm F-1024

PDH:klh

Huddleston & Co., Inc.
Petroleum and Geological Engineers
Texas Registered Engineering Firm F-1024
Houston, Texas

SECURITIES AND EXCHANGE COMMISSION
REGULATION S-X, RULE 4-10

§ 210.4-10 Financial accounting and reporting for oil and gas producing activities pursuant to the Federal securities laws and the Energy Policy and Conservation Act of 1975.

This section prescribes financial accounting and reporting standards for registrants with the Commission engaged in oil and gas producing activities in filings under the Federal securities laws and for the preparation of accounts by persons engaged, in whole or in part, in the production of crude oil or natural gas in the United States, pursuant to section 503 of the Energy Policy and Conservation Act of 1975 (42 U.S.C. 6383) (*EPCA*) and section 11(c) of the Energy Supply and Environmental Coordination Act of 1974 (15 U.S.C. 796) (*ESECA*), as amended by section 505 of EPCA. The application of this section to those oil and gas producing operations of companies regulated for ratemaking purposes on an individual-company-cost-of-service basis may, however, give appropriate recognition to differences arising because of the effect of the ratemaking process.

Exemption. Any person exempted by the Department of Energy from any record-keeping or reporting requirements pursuant to section 11(c) of ESECA, as amended, is similarly exempted from the related provisions of this section in the preparation of accounts pursuant to EPCA. This exemption does not affect the applicability of this section to filings pursuant to the Federal securities laws.

Definitions

(a) *Definitions.* The following definitions apply to the terms listed below as they are used in this section:

(1) *Acquisition of properties.* Costs incurred to purchase, lease or otherwise acquire a property, including costs of lease bonuses and options to purchase or lease properties, the portion of costs applicable to minerals when land including mineral rights is purchased in fee, brokers' fees, recording fees, legal costs, and other costs incurred in acquiring properties.

(2) *Analogous reservoir.* Analogous reservoirs, as used in resources assessments, have similar rock and fluid properties, reservoir conditions (depth, temperature, and pressure) and drive mechanisms, but are typically at a more advanced stage of development than the reservoir of interest and thus may provide concepts to assist in the interpretation of more limited data and estimation of recovery. When used to support proved reserves, an "analogous reservoir" refers to a reservoir that shares the following characteristics with the reservoir of interest:

(i) Same geological formation (but not necessarily in pressure communication with the reservoir of interest);

(ii) Same environment of deposition;

(iii) Similar geological structure; and

(iv) Same drive mechanism.

Instruction to paragraph (a)(2): Reservoir properties must, in the aggregate, be no more favorable in the analog than in the reservoir of interest.

(3) *Bitumen.* Bitumen, sometimes referred to as natural bitumen, is petroleum in a solid or semi-solid state in natural deposits with a viscosity greater than 10,000 centipoise measured at original temperature in the deposit and atmospheric pressure, on a gas free basis. In its natural state it usually contains sulfur, metals, and other non-hydrocarbons.

(4) *Condensate.* Condensate is a mixture of hydrocarbons that exists in the gaseous phase at original reservoir temperature and pressure, but that, when produced, is in the liquid phase at surface pressure and temperature.

(5) *Deterministic estimate.* The method of estimating reserves or resources is called deterministic when a single value for each parameter (from the geoscience, engineering, or economic data) in the reserves calculation is used in the reserves estimation procedure.

(6) *Developed oil and gas reserves.* Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

(i) Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and

(ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

(7) *Development costs.* Costs incurred to obtain access to proved reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas. More specifically, development costs, including depreciation and applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to:

(i) Gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, gas lines, and power lines, to the extent necessary in developing the proved reserves.

(ii) Drill and equip development wells, development-type stratigraphic test wells, and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment, and the wellhead assembly.

(iii) Acquire, construct, and install production facilities such as lease flow lines, separators, treaters, heaters, manifolds, measuring devices, and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems.

(iv) Provide improved recovery systems.

(8) *Development project.* A development project is the means by which petroleum resources are brought to the status of economically producible. As examples, the development of a single reservoir or field, an incremental development in a producing field, or the integrated development of a group of several fields and associated facilities with a common ownership may constitute a development project.

(9) *Development well.* A well drilled within the proved area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive.

(10) *Economically producible.* The term economically producible, as it relates to a resource, means a resource which generates revenue that exceeds, or is reasonably expected to exceed, the costs of the operation. The value of the products that generate revenue shall be determined at the terminal point of oil and gas producing activities as defined in paragraph (a)(16) of this section.

(11) *Estimated ultimate recovery (EUR).* Estimated ultimate recovery is the sum of reserves remaining as of a given date and cumulative production as of that date.

(12) *Exploration costs.* Costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects of containing oil and gas reserves, including costs of drilling exploratory wells and exploratory-type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property (sometimes referred to in part as prospecting costs) and after acquiring the property. Principal types of exploration costs, which include depreciation and applicable operating costs of support equipment and facilities and other costs of exploration activities, are:

(i) Costs of topographical, geographical and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews, and others conducting those studies. Collectively, these are sometimes referred to as geological and geophysical or *G&G* costs.

(ii) Costs of carrying and retaining undeveloped properties, such as delay rentals, ad valorem taxes on properties, legal costs for title defense, and the maintenance of land and lease records.

(iii) Dry hole contributions and bottom hole contributions.

(iv) Costs of drilling and equipping exploratory wells.

(v) Costs of drilling exploratory-type stratigraphic test wells.

(13) *Exploratory well.* An exploratory well is a well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir. Generally, an exploratory well is any well that is not a development well, an extension well, a service well, or a stratigraphic test well as those items are defined in this section.

(14) *Extension well.* An extension well is a well drilled to extend the limits of a known reservoir.

(15) *Field.* An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition. There may be two or more reservoirs in a field that are separated vertically by intervening impervious, strata, or laterally by local geologic barriers, or by both. Reservoirs that are associated by being in overlapping or adjacent fields may be treated as a single or common operational field. The geological terms *structural feature* and *stratigraphic condition* are intended to identify localized geological features as opposed to the broader terms of basins, trends, provinces, plays, areas-of-interest, etc.

(16) *Oil and gas producing activities.*

(i) Oil and gas producing activities include:

(A) The search for crude oil, including condensate and natural gas liquids, or natural gas (“oil and gas”) in their natural states and original locations;

(B) The acquisition of property rights or properties for the purpose of further exploration or for the purpose of removing the oil or gas from such properties;

(C) The construction, drilling, and production activities necessary to retrieve oil and gas from their natural reservoirs, including the acquisition, construction, installation, and maintenance of field gathering and storage systems, such as:

(*1*) Lifting the oil and gas to the surface; and

(*2*) Gathering, treating, and field processing (as in the case of processing gas to extract liquid hydrocarbons); and

(D) Extraction of saleable hydrocarbons, in the solid, liquid, or gaseous state, from oil sands, shale, coalbeds, or other nonrenewable natural resources which are intended to be upgraded into synthetic oil or gas, and activities undertaken with a view to such extraction.

Instruction 1 to paragraph (a)(16)(i): The oil and gas production function shall be regarded as ending at a "terminal point", which is the outlet valve on the lease or field storage tank. If unusual physical or operational circumstances exist, it may be appropriate to regard the terminal point for the production function as:

a. The first point at which oil, gas, or gas liquids, natural or synthetic, are delivered to a main pipeline, a common carrier, a refinery, or a marine terminal; and

b. In the case of natural resources that are intended to be upgraded into synthetic oil or gas, if those natural resources are delivered to a purchaser prior to upgrading, the first point at which the natural resources are delivered to a main pipeline, a common carrier, a refinery, a marine terminal, or a facility which upgrades such natural resources into synthetic oil or gas.

Instruction 2 to paragraph (a)(16)(i): For purposes of this paragraph (a)(16), the term *saleable hydrocarbons* means hydrocarbons that are saleable in the state in which the hydrocarbons are delivered.

(ii) Oil and gas producing activities do not include:

(A) Transporting, refining, or marketing oil and gas;

(B) Processing of produced oil, gas or natural resources that can be upgraded into synthetic oil or gas by a registrant that does not have the legal right to produce or a revenue interest in such production;

(C) Activities relating to the production of natural resources other than oil, gas, or natural resources from which synthetic oil and gas can be extracted; or

(D) Production of geothermal steam.

(17) *Possible reserves.* Possible reserves are those additional reserves that are less certain to be recovered than probable reserves.

(i) When deterministic methods are used, the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves. When probabilistic methods are used, there should be at least a 10% probability that the total quantities ultimately recovered will equal or exceed the proved plus probable plus possible reserves estimates.

(ii) Possible reserves may be assigned to areas of a reservoir adjacent to probable reserves where data control and interpretations of available data are progressively less certain. Frequently, this will be in areas where geoscience and engineering data are unable to define clearly the area and vertical limits of commercial production from the reservoir by a defined project.

(iii) Possible reserves also include incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than the recovery quantities assumed for probable reserves.

(iv) The proved plus probable and proved plus probable plus possible reserves estimates must be based on reasonable alternative technical and commercial interpretations within the reservoir or subject project that are clearly documented, including comparisons to results in successful similar projects.

(v) Possible reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from proved areas by faults with displacement less than formation thickness or other geological discontinuities and that have not been penetrated by a wellbore, and the registrant believes that such adjacent portions are in communication with the known (proved) reservoir. Possible reserves may be assigned to areas that are structurally higher or lower than the proved area if these areas are in communication with the proved reservoir.

(vi) Pursuant to paragraph (a)(22)(iii) of this section, where direct observation has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves should be assigned in the structurally higher portions of the reservoir above the HKO only if the higher contact can be established with reasonable certainty through reliable technology. Portions of the reservoir that do not meet this reasonable certainty criterion may be assigned as probable and possible oil or gas based on reservoir fluid properties and pressure gradient interpretations.

(18) *Probable reserves.* Probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered.

(i) When deterministic methods are used, it is as likely as not that actual remaining quantities recovered will exceed the sum of estimated proved plus probable reserves. When probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the proved plus probable reserves estimates.

(ii) Probable reserves may be assigned to areas of a reservoir adjacent to proved reserves where data control or interpretations of available data are less certain, even if the interpreted reservoir continuity of structure or productivity does not meet the reasonable certainty criterion. Probable reserves may be assigned to areas that are structurally higher than the proved area if these areas are in communication with the proved reservoir.

(iii) Probable reserves estimates also include potential incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than assumed for proved reserves.

(iv) See also guidelines in paragraphs (a)(17)(iv) and (a)(17)(vi) of this section.

(19) *Probabilistic estimate.* The method of estimation of reserves or resources is called probabilistic when the full range of values that could reasonably occur for each unknown parameter (from the geoscience and engineering data) is used to generate a full range of possible outcomes and their associated probabilities of occurrence.

(20) *Production costs.*

(i) Costs incurred to operate and maintain wells and related equipment and facilities, including depreciation and applicable operating costs of support equipment and facilities and other costs of operating and maintaining those wells and related equipment and facilities. They become part of the cost of oil and gas produced. Examples of production costs (sometimes called lifting costs) are:

(A) Costs of labor to operate the wells and related equipment and facilities.

(B) Repairs and maintenance.

(C) Materials, supplies, and fuel consumed and supplies utilized in operating the wells and related equipment and facilities.

(D) Property taxes and insurance applicable to proved properties and wells and related equipment and facilities.

(E) Severance taxes.

(ii) Some support equipment or facilities may serve two or more oil and gas producing activities and may also serve transportation, refining, and marketing activities. To the extent that the support equipment and facilities are used in oil and gas producing activities, their depreciation and applicable operating costs become exploration, development or production costs, as appropriate. Depreciation, depletion, and amortization of capitalized acquisition, exploration, and development costs are not production costs but also become part of the cost of oil and gas produced along with production (lifting) costs identified above.

(21) *Proved area.* The part of a property to which proved reserves have been specifically attributed.

(22) *Proved oil and gas reserves.* Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

(i) The area of the reservoir considered as proved includes:

(A) The area identified by drilling and limited by fluid contacts, if any, and

(B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.

(iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.

(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:

(A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and

(B) The project has been approved for development by all necessary parties and entities, including governmental entities.

(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

(23) *Proved properties.* Properties with proved reserves.

(24) *Reasonable certainty.* If deterministic methods are used, reasonable certainty means a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate. A high degree of confidence exists if the quantity is much more likely to be achieved than not, and, as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease.

(25) *Reliable technology.* Reliable technology is a grouping of one or more technologies (including computational methods) that has been field tested and has been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation.

(26) *Reserves.* Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project.

Note to paragraph (a)(26): Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (*i.e.*, absence of reservoir, structurally low reservoir, or negative test results). Such areas may contain prospective resources (*i.e.*, potentially recoverable resources from undiscovered accumulations).

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

(28) *Resources.* Resources are quantities of oil and gas estimated to exist in naturally occurring accumulations. A portion of the resources may be estimated to be recoverable, and another portion may be considered to be unrecoverable. Resources include both discovered and undiscovered accumulations.

(29) *Service well.* A well drilled or completed for the purpose of supporting production in an existing field. Specific purposes of service wells include gas injection, water injection, steam injection, air injection, salt-water disposal, water supply for injection, observation, or injection for in-situ combustion.

(30) *Stratigraphic test well.* A stratigraphic test well is a drilling effort, geologically directed, to obtain information pertaining to a specific geologic condition. Such wells customarily are drilled without the intent of being completed for hydrocarbon production. The classification also includes tests identified as core tests and all types of expendable holes related to hydrocarbon exploration. Stratigraphic tests are classified as “exploratory type” if not drilled in a known area or “development type” if drilled in a known area.

(31) *Undeveloped oil and gas reserves.* Undeveloped oil and gas reserves are reserves of any category 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.

(i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.

(ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time.

(iii) Under no circumstances shall estimates for undeveloped reserves be attributable 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 projects in the same reservoir or an analogous reservoir, as defined in paragraph (a)(2) of this section, or by other evidence using reliable technology establishing reasonable certainty.

(32) *Unproved properties.* Properties with no proved reserves.