CALLON PETROLEUM CO
Form 10-K
March 15, 2011

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

Form 10-K

for the year ended

December 31, 2010

[X]	Annual report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934 For the fiscal year ended December 31, 2010
	or
[ ]	Transition report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934 For the transition period from____ to____

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
(Address of principal executive offices)	(Zip Code)

601-442-1601
(Registrant's telephone number, including area code)

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

Title of each class:	Name of each exchange on which registered:
Common Stock, $.01 par value	New York Stock Exchange

Securities registered pursuant to section 12 (g) of the Act: None

Indicate by check mark whether the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.

Yes [ ] No [X]

Indicate by check mark whether the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act.

Yes [ ] No [X]

Indicate by check mark whether registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

Yes [X] No [ ]

Indicate by check mark 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 (232.405 of this chapter) 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 registrants 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 definition 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 [X]

Non-accelerated filer [ ] Smaller reporting company [ ]

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).

Yes [ ] No [X]

The aggregate market value of the voting and non-voting common equity stock held by non-affiliates of the registrant was $165.3 million as of June 30, 2010.

As of March 3, 2011, 39,105,130 shares of the Registrant's common stock, par value $.01 per share, were outstanding.

Documents Incorporated by Reference

Portions of the definitive Proxy Statement of Callon Petroleum Company (to be filed no later than 120 days after December 31, 2010) relating to the Annual Meeting of Stockholders to be held on May 12, 2011, which are incorporated into Part III of this Form 10-K.

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Special Note Regarding Forward Looking Statements

All statements, other than historical fact or present financial information, may be deemed to be forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. All statements that address activities, outcomes and other matters that should or may occur in the future, including, without limitation, statements regarding the financial position, business strategy, production and reserve growth and other plans and objectives for our future operations, are forward-looking statements. Although we believe the expectations expressed in such forward-looking statements are based on reasonable assumptions, such statements are not guarantees of future performance. We have no obligation and make no undertaking to publicly update or revise any forward-looking statements, except as may be required by law.

Forward-looking statements include the items identified in the preceding paragraph, information concerning possible or assumed future results of operations and other statements in this Form 10-Q identified by words such as “anticipate,” “project,” “intend,” “estimate,” “expect,” “believe,” “predict,” “budget,” “projection,” “goal,” “plan,” “forecast,” “target” or si

You should not place undue reliance on forward-looking statements. They are subject to known and unknown risks, uncertainties and other factors that may affect our operations, markets, products, services and prices and cause our actual results, performance or achievements to be materially different from any future results, performance or achievements expressed or implied by the forward-looking statements. In addition to any assumptions and other factors referred to specifically in connection with forward-looking statements, risks, uncertainties and factors that could cause our actual results to differ materially from those indicated in any forward-looking statement include, but are not limited to:

- the timing and extent of changes in market conditions and prices for commodities (including regional basis differentials);
- our ability to transport our production to the most favorable markets or at all;
- the timing and extent of our success in discovering, developing, producing and estimating reserves;
- our ability to fund our planned capital investments;
- the impact of government regulation, including any increase in severance or similar taxes, legislation relating to hydraulic fracturing, the climate and over-the-counter derivatives;
- the costs and availability of oilfield personnel services and drilling supplies, raw materials, and equipment and services;
- our future property acquisition or divestiture activities;
- the effects of weather;
- increased competition;
- the financial impact of accounting regulations and critical accounting policies;
- the comparative cost of alternative fuels;
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conditions in capital markets, changes in interest rates and the ability of our lenders to provide us with funds as agreed;

- credit risk relating to the risk of loss as a result of non-performance by our counterparties; and
- any other factors listed in the reports we have filed and may file with the Securities and Exchange Commission ("SEC").

We caution you that the forward-looking statements contained in this Form 10-K are subject to all of the risks and uncertainties, many of which are beyond our control, incident to the exploration for and development, production and sale of oil and natural gas. These risks include, but are not limited to, the risks described in Item 1A of this Annual Report on Form 10-K for the year ended December 31, 2010 (the "2010 Annual Report on Form 10-K"), and all quarterly reports on Form 10-Q filed subsequently thereto ("Form 10-Qs").

Should one or more of the risks or uncertainties described above or elsewhere in this Form 10-K occur, or should underlying assumptions prove incorrect, our actual results and plans could differ materially from those expressed in any forward-looking statements. We specifically disclaim all responsibility to publicly update any information contained in a forward-looking statement or any forward-looking statement in its entirety and therefore disclaim any resulting liability for potentially related damages.

All forward-looking statements attributable to us are expressly qualified in their entirety by this cautionary statement.

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DEFINITIONS

All defined terms under Rule 4-10(a) of Regulation S-X shall have their statutorily prescribed meanings when used in this report. As used in this document:

- 3-D: three-dimensional.
- ARO: Asset Retirement Obligation
- B/d: barrels of oil or natural gas liquids per day.
- Bbl or Bbls: barrel or barrels of oil.
- Bcf: billion cubic feet.
- Boe: barrel of oil equivalent, determined by using the ratio of one Bbl of oil or NGLs to six Mcf of gas.
- Boe/d: boe per day.
- BOEMRE: Bureau of Ocean Energy Management, Regulation and Enforcement; formerly the Minerals Management Service ("MMS")
- Btu: a British thermal unit, a measure of heating value, which is approximately equal to one Mcf.
- LIBOR: London Interbank Offered Rate.
- LNG: liquefied natural gas.
- Mbbls: thousand barrels of oil.
- Mboe: thousand boe.
- Mboe/d: Mboe per day.
- Mcfe: thousand cubic feet of natural gas.
- Mcf/d: Mcf per day.
- MMbbls: million barrels of oil.
- MMboe: million boe.
- MMBtu: million Btu.
- MMBtu/d: MMBtu per day.
- MMcf: million cubic feet of natural gas.
- MMcf/d: MMcf per day.
- NGL or NGLs: natural gas liquids, which are expressed in barrels.
- NYMEX: New York Mercantile Exchange.
- Oil: includes crude oil and condensate.
- PDP: proved developed reserves.
- PUD: proved undeveloped reserves.
- SEC: United States Securities and Exchange Commission.
- Section: land area containing 640 acres
- US GAAP: Generally Accepted Accounting Principles in the United States

With respect to information relating to our working interest in wells or acreage, “net” oil and gas wells or acreage is determined by multiplying gross wells or acreage by our working interest therein. Unless otherwise specified, all references to wells and acres are gross.

PART I.

Items 1 and 2 - BUSINESS and PROPERTIES

Overview and Business Strategy

Callon Petroleum Company has been engaged in the exploration, development, acquisition and production of oil and gas properties since 1950. The 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 unl the context requires otherwise.

Callon Petroleum Company is engaged in the development, production, exploration and acquisition of oil and gas properties. In late 2008, our management shifted our operational focus from exploration in the Gulf of Mexico to the acquisition and development of onshore properties located in the Wolfberry play of the Permian Basin in Texas and the Haynesville Shale area in Louisiana. As of December 31, 2010, we had estimated net proved reserves of 8.1 MMBbls and 33.0 Bcf, or 13.6 MMBOE. Of these reserves, approximately 50.0% were located onshore in the Permian Basin Wolfberry and Haynesville Shale plays, compared with 16.5% located onshore at December 31, 2009.

Our Business Strategy

Our goal is to increase stockholder value by:

- Increasing reserves and production levels by using cash flows from, or monetization of, our Gulf of Mexico properties to acquire and develop lower risk, long-life onshore oil and gas properties;
- Increasing our reserve life and predictability of production by focusing on acquisition and development of long-life onshore properties;
- Diversifying risk by substantially increasing the number of productive wells we own; and
- Strengthening our balance sheet by focusing on maintaining liquidity and a reduction of our average debt per barrel of oil equivalent ("Boe") of proved reserves.

Our Strengths

We believe that we are well positioned to achieve our business objectives and to execute our strategy because of the following competitive strengths at year-end 2010:

- We have a substantial inventory of onshore drilling locations, with an estimated 132 net drilling locations on 40-acre spacing and an additional 166 net drilling locations on 20-acre spacing in the Wolfberry play of the Permian Basin and four net locations in the Haynesville area.
- Our offshore properties generate substantial cash flow, which we can deploy in the acquisition, exploration and development of onshore properties.
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Our management team is experienced in oil and gas acquisitions, exploration, development and production in the areas in which we are focusing our operations.

- On December 31, 2010, our total liquidity position was approximately $47 million, including $17 million of available cash and $30 million of unused borrowing base available under our senior secured credit facility. The borrowing base was increased by 50.0% over its previous level at the last redetermination in the fourth quarter of 2010. The next redetermination is scheduled for April 2011.

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Recent Developments

As discussed in Note 19 included in Part II, Item 8 of this filing, during February 2011, we received $73.7 million in net proceeds through the public offering of 10.1 million shares of our common stock, which included the issuance of 1.1 million shares pursuant to the underwriters' over-allotment option. Immediately following the completion of the equity offering, we called for redemption $31.0 million principal amount of our 13% senior notes due 2016. We expect to complete the redemption of these notes by March 19, 2011, which will result in a gain on the early extinguishment of debt of approximately $2.0 million. We also completed an arbitration proceeding with our former joint interest partner in the Entrada project, which is more fully discussed in Note 19.

Exploration and Development Activities

During 2010, capital expenditures on an accrual basis for exploration and development costs related to oil and gas properties included these expenditures (in millions):

20 wells drilled, 11 wells producing, on the Permian Basin acreage	$32.0
Natural gas well in the Haynesville Shale gas play and site development for future wells	10.9
Leasehold acquisitions and seismic	4.0
Costs incurred on legacy properties	1.6
Plugging and abandonment costs in the Gulf of Mexico	2.4
Capitalized interest ($2.0 million) and overhead ($11.8 million) allocable directly to exploration and development projects.	13.8
Total 2010 capital expenditures (a)	$64.7

(a) The above costs exclude approximately $6.6 million of capital costs incurred on legacy properties as a result of certain joint interest billings not being recovered from a joint interest partner. Under the full-cost method of accounting, these costs are capitalized to the Company's full cost pool. Inclusive of this amount, 2010 capital expenditures totaled $71.2 million. See Note 19 included in Part II, Item 8 of this filing for additional information regarding the write-off of certain receivables.

As a result of the previously discussed shift in our operational focus from offshore in the Gulf of Mexico to onshore in the Wolfberry play of the Permian Basin and the Haynesville Shale play, we expect that substantially all of our 2011 capital expenditures will be focused on the development and acquisition of onshore properties in the United States, with only limited amounts of capital expended to maintain our offshore properties. Our projected 2011 capital expenditures budget is outlined within Management's Discussion and Analysis and Results of Operations, which is included in Part II, Item 7 of this filing.

Acquisitions and Divestitures

The Company increased its interest in the East Bloxom Development Area of the Permian Basin, located in Upton County, from an average 47% working interest to 100% working interest through a number of acquisitions and farm-ins for which the Company paid approximately $1.0 million during 2010, of which $0.1 million was recorded acquisition expenses during 2010. As a result, Callon now controls the activity in three development areas encompassing 11 Sections.

Oil and Gas Properties

As of December 31, 2010, our estimated net proved reserves totaled 13.6 MMBoe and included 8.1 MMBbls and 33.0 Bcf, with a pre-tax present value, discounted at 10%, of $205.5 million. Pre-tax present value may be deemed to be a non-US GAAP financial measure, which we reconcile to the US GAAP standardized measure of $198.9 million in the proved reserves table presented later within this section of the filing. Oil constitutes approximately 60% on an equivalent basis of our total estimated net proved reserves, and approximately 49% 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, 2010:

		Estimated Net Proved Reserves			Pre-tax Discounted Present Value
	Operator	Oil (MBbls)	Gas (MMcf)	Total (MBoe) (a)	($000) (b)(c)(d)
Onshore:					
Permian Basin	Callon	3,410	6,247	4,451	$41,438
Haynesville Shale	Callon	-	13,621	2,270	7,369
Total Onshore		3,410	19,868	6,721	48,807
Gulf of Mexico Deepwater:					
Mississippi Canyon 538/582 “Medusa”	Murphy	4,020	3,011	4,522	125,678
Garden Banks Block 341 “Habanero”	Shell	642	4,592	1,408	28,411
Total Gulf of Mexico Deepwater		4,662	7,603	5,930	154,089
Gulf of Mexico Shelf and Other:					
West Cameron Block 295	Mariner Energy	8	1,466	253	4,714
East Cameron Block 109	Energy Partners LTD	13	928	167	3,056
East Cameron Block 2	Apache	8	770	136	2,572
East Cameron Block 257	SPN Resources	1	899	150	1,906
Other	Various	47	1,423	284	(9,612)
Total Gulf of Mexico Shelf and Other		77	5,486	990	2,636
Total Net Proved Reserves		8,149	32,957	13,641	$205,532

(a) We convert Mcf to Boe using a conversion ratio of six Mcf to one Boe. This ratio, which is typical in the industry and represents the approximate energy equivalent of an Mcf to a Boe, does not reflect to economic equivalency of an Mcf of gas compared with a Boe of oil or natural gas liquids. On an economic basis, a barrel of oil has a substantially higher price than six Mcf of natural gas.

(b) 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, 2010, as set forth in the Company’s reserve reports prepared by its independent petroleum reserve engineers, Huddleston & Co., Inc.

(c) Includes a reduction for estimated plugging and abandonment costs that is reflected as a liability on our balance sheet at December 31, 2010, 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 15 of our consolidated financial statements. The negative Pre-Tax Present Value of the “Other” reflects plugging and abandonment obligations exceeding the future net cash flows, obligations of which most are estimated to occur within the next five years,

(d)

The Company uses the financial measure "Pre Tax Discounted Present Value" which is a non-US GAAP financial measure. The Company believes that Pre Tax Discounted 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 calculated in accordance with the guidance issued by the FASB for disclosures about oil and gas producing activities for our proved reserves as of December 31, 2010 was $198.9 million inclusive of the $6.6 million discounted estimated future income taxes relating to such future net revenues. Year-end average pricing was $5.10 per Mcf for natural gas and $78.07 per Bbl for oil.

Onshore Properties

Onshore proved reserves accounted for approximately 50% of year-end 2010 proved reserves, demonstrating our progress toward our strategic goal of diversifying our reserve portfolio.

Permian Basin

During the fourth quarter of 2009, Callon acquired an interest in Permian Basin properties, which included 22 producing wells with associated proved reserves of 1.6 MMBoe. During 2010, the Company drilled an additional 20 wells targeting the Wolfberry trend, of which 11 were producing by year-end, thereby increasing total average daily production in the Permian Basin to approximately 550 boe/d as of December 31, 2010. The remaining 9 wells drilled during 2010 are scheduled to be fracture stimulated and brought online during the first and second quarters of 2011. Early in 2011, we entered into an agreement with our fracture stimulation service provider providing for a minimum of three well stimulations per month in 2011. During 2011, the Company plans to drill up to an additional 44 wells.

The Company's primary target in the Permian Basin is the Wolfberry play, which is located in Crockett, Ector, Midland and Upton Counties, Texas. This play is a proven, low-permeability oil play and includes the Sprayberry, Dean, and Wolfcamp formations. The Company currently owns approximately 8,800 net acres within the Permian Basin, approximately 80% of which is prospective for the Wolfberry Play and provides a drilling inventory of 132 additional drilling locations based on a 40-acre spacing development. Approximately 33% of our 2010 proved reserves were attributable to our properties in the Wolfberry play of the Permian Basin.

Haynesville Shale

During the third quarter of 2009, Callon acquired a 69% working interest in a Haynesville Shale unit located in Southern Bossier Parish, Louisiana, and currently owns approximately 430 net acres in the Haynesville Shale. Initial production from the George R. Mills Well No. 1H, our first well completed since acquiring this property in 2009, commenced on September 3, 2010. To date as of March 2011, the well has produced 1.4 billion cubic feet of natural gas and is currently producing at a restricted rate of 5.0 MMcfe/d. We have an additional four net drilling locations on the 430-net acre unit in which we have a 69% working interest. The Company also performed some site development work for future wells and is awaiting improvement in natural gas prices before resuming development of the field. Approximately 17% of our year-end 2010 proved reserves were attributable to our Haynesville Shale property.

Gulf of Mexico Deepwater Properties

Medusa, Mississippi Canyon Blocks 538/582

Our Medusa deepwater discovery that occurred during 1999, in which we own a 15% working interest, is located in 2,235 feet of water approximately 50 miles offshore Louisiana. Murphy Exploration & Production Company ("Murphy"), the operator, owns a 60% working interest and ENI Deepwater, LLC, owns the remaining 25% working interest.

During 2010 the Medusa field produced 593 MBoe net to us from eight wells which accounted for 35% of our total production. Most of the wells are still producing from their initial completions and have 2.4 MMBoe of proved developed non-producing reserves that will be accessed by recompletions in the existing wells. Another 1.2 MMBoe 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 as of December 31, 2010 is estimated 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 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

The Habanero property, in which we own an 11.25% working interest in its wells, is located in 2,015 feet of water approximately 115 miles offshore Louisiana. Production from the Habanero 52 oil sand commenced in late November 2003 and from the Habanero 55 gas sand in January 2004. The well is operated by Shell Deepwater Development Inc., which owns a 55% working interest, with the remaining working interest owned by Murphy.

During 2010, Habanero produced 232 MBoe net to us from two wells which accounted for 14% 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, 2010 to be in 2012 for one well and 2013 for the other.

Gulf of Mexico Shelf and Other Properties

We own interests in 18 producing wells in twelve oil and gas fields in the shelf area of the Gulf of Mexico. These wells produced 616 MBOE net to our interest in 2010, which accounted for 37% of our total production.

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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 were effective for the Company’s year-end financial statements and Annual Report on Form 10-K for the year ended December 31, 2009, and as such the reserves and related information for 2009 and 2010 are presented consistent with the requirements of the new rule. The new rule does not require prior-year reserve information to be restated, and as such 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 MBbls for oil and in MMcf for natural gas at a pressure base of 15.025 pounds per square inch. Total volumes are presented in MBoe. For the MBoe computation, 6,000 cubic feet of gas are the equivalent of one barrel of oil.

The following table sets forth certain information about our estimated proved reserves. All of our proved reserves are located in the continental United States and in federal and state waters in the Gulf of Mexico.

	Years Ended December 31,		
	2010	2009	2008
Proved developed:			
Oil (MBbls)	4,503	4,346	4,663
Gas (MMcf)	12,715	12,301	13,463
MBoe	6,622	6,396	6,907
Proved undeveloped:			
Oil (MBbls)	3,645	2,133	1,364
Gas (MMcf)	20,241	6,802	5,189
MBoe	7,019	3,266	2,229
Total proved:			
Oil (MBbls)	8,149	6,479	6,027
Gas (MMcf)	32,957	19,103	18,652
MBoe	13,641	9,663	9,136
Estimated pre-tax future net cash flows (a)	$379,448	$216,702	$113,555
Pre-tax discounted present value (a) (b)	$205,532	$137,368	$86,591

Standardized measure of discounted future net cash flows(a) (b)	$198,916	$135,921	$86,305

(a)Includes a reduction for estimated plugging and abandonment costs that is reflected as a liability on our balance sheet at December 31, 2010, in accordance with accounting for asset retirement obligations rules.

(b)The Company uses the financial measure “Pre Tax Present Value” which is a non-US GAAP financial measure. The Company believes 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 calculated in accordance with the guidance issued by the FASB for disclosures about oil and gas producing activities for our proved reserves as of December 31, 2010 was $198.9 million inclusive of the $6.6 million discounted estimated future income taxes relating to such future net revenues. Year-end average pricing was $5.10 per Mcf for natural gas and $78.07 per Bbl for oil.

See Note 15 of our Consolidated Financial Statements for the additional information regarding the Company’s reserves including its estimates of proved reserves, PDPs, PUDs and the Company’s estimates of future net cash flows and discounted future net cash flows from proved reserves.

Proved Undeveloped Reserves

The Company reviews annually its PUDs to ensure an appropriate plan exists for development. Generally, reserves for onshore properties are recognized as PUDs only if the Company has plans to convert the PUDs into PDPs within five years of the date they are first recorded as PUDs. The following table summarizes the Company's recorded PUDs:

	PUDs (in MBoe) at December 31,		
	2010	2009	2008
Permian Basin	2,928	932	-
Haynesville Shale	1,757	-	-
Total Onshore PUDs	4,685	932	-
Medusa	1,186	1,186	1,081
Habanero	1,148	1,148	1,148
Total Deepwater PUDs	2,334	2,334	2,229
Total Shelf and other PUDs	-	-	-
Total PUDs	7,019	3,266	2,229

Our plans are to develop our deepwater PUDS by side tracking existing wells when the zones currently being produced by the wells are depleted. The Company's current plans forecast that the two producing zones in the Habanero field will be depleted one in 2012 and the other in 2013. In the Medusa field, the Company expects several recompletes to occur prior to 2012 with current producing reserves forecasted to reach their economic depletion point in 2022. Upon the depletion of currently producing reserves, the Company plans to develop its deepwater PUDs. During 2010, Callon did not convert any offshore PUDs to PDPs. The Company's plans to develop its PUDs in the Permian Basin include a multi-year drilling program, which is expected to be completed on existing acreage within three to five years. Similarly, the Company plans to resume drilling on its Haynesville Shale property once gas prices improve, and expects to convert its existing PUDs within the next five years.

From December 31, 2009 to December 31, 2010, our PUDs increased 115% from 3,266 MBOE to 7,019 MBOE. As a result of acquisitions during 2009, we added 932 MBoe as compared to 2008. We then added 3,752 MBoe as a result of successful drilling during 2010 and commensurate PUDs associated with such drilling. None of these additions to our PUD reserves were offset by amounts no longer deemed to be economic PUDs at year-end. At January 1, 2010, we had 3,266 MBOE of proved undeveloped reserves. Of these PUD reserves, 23% were converted to proved developed producing reserves by year end 2010, at a total cost of $6.4 million, net.

We plan to develop our proved undeveloped reserves within a five-year time frame. The basis for our development plans are (i) allocation of capital to projects in our 2011 capital budget and (ii) in subsequent years, on the basis of capital allocation in our five-year business plan, each of which generally is governed by our expectations of internally generated cash flow. Reserve calculations at any end-of-year period are representative of our development plans at that time. Changes in commodity pricing, oilfield service costs and availability, and other economic factors may lead to changes in development plans.

Controls Over Reserve Estimates

Compliance as it relates to reporting the Company's reserves is the responsibility of our Senior Vice President of Operations, who with over 30 years of industry experience including 25 years as a manager, is our principal engineer. In addition to his years of experience, our principal engineer holds a degree in petroleum engineering and asset evaluation and management.

Callon's controls over reserve estimates included retaining Huddleston & Co., Inc., a Texas registered engineering firm, as our independent petroleum and geological firm. The Company provided to Huddleston information about our oil and gas properties, including production profiles, prices and costs, and Huddleston prepared its own estimates of the reserves attributable to the Company's properties. All of the information regarding reserves in this annual report is derived from Huddleston's report, which is included as an Exhibit to this annual report. The principal engineer at Huddleston responsible for preparing the Company's reserve estimates has over 30 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 and being a member of the Society of Petroleum Engineers.

The Audit Committee of our Board of Directors meets with management, including the Senior Vice President of Operations, to discuss matters and policies including those related to reserves. 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.

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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.

	Years Ended December 31,		
	2010	2009	2008
	(in thousands, except per unit data)		
Production			
Natural gas (Mcf)	4,892	5,740	5,839
Oil (MBbl)	859	1,012	942
Total (MBoe)	1,674	1,969	1,915
Revenues			
Natural gas sales	$24,639	$27,417	58,349
Oil sales	65,243	73,842	82,963
Total revenues	$89,882	$101,259	$141,312
Lease Operating Expenses			
Production costs	$16,094	$16,778	$17,605
Severance/production taxes	816	528	626
Gathering	802	1,141	977
Total lease operating expenses	$17,712	$18,447	$19,208
Realized prices			
Natural gas ($/Mcf, including realized gains (losses) on derivatives)	$5.04	$4.78	$9.99
Natural gas ($/Mcf, excluding realized gains (losses) on derivatives)	4.91	4.45	10.10
Oil ($/Bbl, including realized gains (losses) on derivatives)	75.97	73.00	88.07
Oil ($/Bbl, excluding realized gains (losses) on derivatives)	75.97	55.84	97.37
Operating costs per Boe - Total Consolidated			
Production costs	$9.61	$8.52	$9.19
Severance/production taxes	0.49	0.27	0.33
Gathering	0.48	0.58	0.51
DD&A	19.00	16.99	33.45
Interest	7.95	9.70	12.52
Total operating costs per Boe	$37.53	$36.06	$56.00

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Present Activities and Productive Wells

The following table sets forth the wells drilled and completed during the periods indicated. All such wells were drilled in the continental United States and in federal and state waters in the Gulf of Mexico. At December 31, 2010 we had nine oil wells awaiting fracture stimulation and were in the process of drilling two wells.

	Years ended December 31,					
	2010		2009		2008	
	Gross	Net	Gross	Net	Gross	Net
Development:						
Oil	4	3.69	-	-	1	0.15
Gas	-	-	-	-	-	-
Non-productive	-	-	-	-	1	0.50
Total	4	3.69	-	-	2	0.65
Exploration:						
Oil	16	15.69	-	-	-	-
Gas	1	0.69	-	-	-	-
Non-productive	-	-	-	-	2	0.22
Total	17	16.38	-	-	2	0.22

The following table sets forth productive wells as of December 31, 2010:

	Oil Wells		Gas Wells	
	Gross	Net	Gross	Net
Working interest	45	32.02	21	7.87
Royalty interest	3	0.10	6	0.15
Total	48	32.12	27	8.02

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, 2010, 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, 2010. A portion of our Texas acreage requires continued drilling to hold the acreage for which we have included in our development plans, though the renewal of this acreage, if necessary, is not considered material. We have two federal blocks in offshore waters, 11,520 gross or 8,446 net acres, which will expire within the next two years for which we have a carrying value of $3.5 million. We are currently negotiating potential farm-outs of this acreage. In addition we have three other federal blocks in offshore waters, 16,706 gross or 6,489 net acres, scheduled to expire within the next two years which have no carrying value and for which we have no current development plans.

	Developed		Undeveloped	
	Gross	Net	Gross	Net
Louisiana	4,848	2,339	931	699
Texas	6,160	5,520	3,634	3,306
Federal onshore	-	-	64,963	64,963
Federal waters	53,211	18,386	72,955	41,919
Total	64,219	26,245	142,483	110,887

Title to Properties

The Company believes that the title to its 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. The Company's 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, farm-out 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 the Company's rights to production revenues, the characteristic has been taken into account in calculating Callon's net revenue interests and in estimating the size and value of its reserves. The Company believes that the burdens and obligations affecting our properties it's conventional in the industry for properties of the kind owned by Callon.

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:

	Percentage of Total Revenue for the year ended December 31,		
	2010	2009	2008
Shell Trading Company	44%	45%	33%
Plains Marketing, L.P.	20%	23%	23%
Louis Dreyfus Energy Services	13%	15%	16%
Other	23%	17%	28%
Total	100%	100%	100%

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 Callon's ability to market future oil and gas production. We are not currently committed to provide a fixed and determinable quantity of oil or gas in the near future under our contracts.

Corporate Offices

The Company's headquarters are located in Natchez, Mississippi, in approximately 51,500 square feet of owned space. We also maintain leased business offices in Houston and Midland, 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

Callon had 79 employees as of December 31, 2010, which included eight petroleum engineers and four petroleum geoscientists. None of the Company's employees are currently represented by a union, and the Company believes that it has good relations with its employees.

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 Bureau of Ocean Energy Management, Regulation and Enforcement ("BOEMRE"), and require compliance with detailed BOEMRE (a) regulations and orders. Lessees must obtain BOEMRE approval for exploration, exploitation and production plans and applications for permits to drill prior to the commencement of such operations. Since the April 20, 2010 blowout and oil spill at the BP Deepwater Horizon Macondo oil well, the BOEMRE has issued numerous Notices to Lessees and other guidance documents as well as an Interim Final Rule augmenting the existing regulations with more stringent safety, engineering and environmental requirements. The BOEMRE has also recently issued a rule requiring that all operators in the OCS formulate detailed Safety and Environmental Management Systems to improve the safety of their operations on the OCS. Current BOEMRE regulations restrict the flaring or venting of natural gas, and prohibit the flaring of liquid hydrocarbons and oil without prior authorization. The BOEMRE is considering whether to require flaring rather than venting, where practical, to reduce the potential effect of greenhouse gas emissions.

BOEMRE 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 BOEMRE has promulgated other regulations and a Notice to Lessees governing the plugging and abandonment of wells located offshore and the installation and decommissioning of production facilities. To cover the various obligations of lessees on the OCS, BOEMRE 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, BOEMRE 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.

As stated above, the April 20, 2010 blowout and oil spill at the BP Deepwater Horizon oil rig has prompted the federal government to impose heightened regulation of oil and gas exploration and production on the OCS. Especially with respect to deepwater operations, the BOEMRE has issued rules that are more stringent than the rules issued by the MMS, and has announced its intention to issue additional safety rules and be more scrupulous in implementing existing environmental requirements in the future. Legislation has been introduced in the United States Congress to toughen the regulation of oil and gas exploration and production on the OCS. In addition, the National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling, whose members were appointed by President Obama, issued a report proposing, among other things, fundamental reform of the regulation of oil and gas exploration and production on the OCS. The tightening of regulation on the OCS could impose higher costs on, and render it more difficult to timely obtain regulatory approval of our proposed activities on the OCS, especially as to deepwater projects.

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 BOEMRE 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.

In response to concerns that the former Minerals Management Service's ("MMS") revenue-generating and resource development functions were at odds with its safety and environmental regulatory functions, the Department of Interior plans to divide the BOEMRE into three separate agencies: the Bureau of Ocean Energy Management ("BOEM"), to be the resource manager for conventional and renewable energy and mineral resources on the OCS; the Bureau of Safety and Environmental Enforcement ("BSEE"), to promote and enforce safety in offshore energy exploration and production operations; and the Office of Natural Resources Revenue ("ONRR"), to collect and distribute royalties, rents, fees and other revenues, including the development of regulations with respect to revenue valuation and collection and enforcement activities. The ONRR began operations on October 1, 2010. The BOEM and the BSEE are scheduled to undergo a phased implementation program beginning in January 2011 and continuing for at least twelve months.

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 ("GHG") Regulation. Although federal legislation regarding the control of greenhouse gasses or GHGs seems unlikely, the Environmental Protection Agency ("EPA") has been moving forward with rulemaking to regulate GHGs as pollutants under the Clean Air Act ("CAA"). These GHG regulations could require us to incur increased operating costs and could have an adverse effect on demand for the oil and natural gas we produce.

On June 3, 2010, EPA published its so-called GHG tailoring rule that will phase in federal prevention of significant deterioration (PSD) permit requirements for new sources and modifications, and Title V operating permits for all sources, that have the potential to emit specific quantities of GHGs. Those permitting provisions, when they become applicable to our operations, could require controls or other measures to reduce GHG emissions from new or modified sources, and we could incur additional costs to satisfy those requirements. On November 30, 2010, EPA published a rule establishing GHG reporting requirements for sources in the petroleum and natural gas industry, requiring those sources to monitor, maintain records on, and annually report their GHG emissions, with the first annual report -- for 2010 -- being due in March of 2011. Although this rule does not limit the amount of GHGs that can be emitted, it could require us to incur costs to monitor, keep records of, and report GHG emissions associated with our operations.

In addition to 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. Congress is currently considering legislation to amend the federal Safe Drinking Water Act to remove the exemption for hydraulic fracturing operations and require reporting and disclosure of chemicals used by the oil and gas industry in the hydraulic fracturing process. Hydraulic fracturing involves the injection of water, sand and chemicals under pressure into rock formations to stimulate oil and natural gas production. Sponsors of bills pending before the Senate and House of Representatives have asserted that chemicals used in the fracturing process could adversely affect drinking water supplies. A number of states have or are considering hydraulic fracturing regulation. Potential federal as well as existing and potential state regulation could cause us to incur substantial compliance costs, and the requirement could negatively affect our ability to conduct fracturing activities on our assets.

Surface Damage Statues ("SDAs"). In addition, eleven states have enacted 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, BOEMRE 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 included, and claims for damages to property, employees, other persons, and the environment resulting from the Company's operations could have on its activities.

Available Information

We make available free of charge on our Internet web site (www.callon.com) our Annual Report on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and other filings pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934, and amendments to such filings, as soon as reasonably practicable after each are electronically filed with, or furnished to, the Securities and Exchange Commission (the "SEC"). You may read and copy any materials we file with the SEC at the SEC's Public Reference Room at 100 F Street, NE., Washington, DC 20549. You may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. The SEC also maintains an Internet site (www.sec.gov) that contains reports, proxy and information statements, and other information regarding issuers, like Callon, that file electronically with the SEC.

We also make available within the Investors section of our Internet web site our Code of Business Conduct and Ethics, Corporate Governance Guidelines, and Audit, Compensation and Nominating and Governance Committee Charters, which have been approved by our board of directors. We will make timely disclosure by a Current Report on Form 8-K and on our web site of any change to, or waiver from, the Code of Business Conduct and Ethics for our principal executive and senior financial officers. A copy of our Code of Business Conduct and Ethics is also available, free of charge by writing us at: Chief Financial Officer, Callon Petroleum Company, P.O. Box 1287, Natchez, MS 39121.

Item 1A. Risk Factors

Risk Factors

Future economic conditions in the U.S. and key international markets may materially adversely impact our operating results. The U.S. and other world economies are slowly recovering from a recession that began in 2008 and extended through 2010. While modest growth has resumed, there are likely to be significant long-term effects resulting from the recession and credit market crisis, including a future global economic growth rate that is slower than we have experienced in recent years. In addition, more volatility may occur before a sustainable growth rate is achieved. Global economic growth drives demand for energy from all sources, including fossil fuels. A lower future economic growth rate could result in decreased demand growth for our crude oil and natural gas production as well as lower commodity prices, which would reduce our cash flows from operations and our profitability.

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, and the oil and gas markets are cyclical. Extended periods of low prices for oil or gas will have a material adverse effect on us. 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 profit or loss we incur in exploring for and developing our reserves; and
- the value of our oil and gas properties.

Natural gas prices have been depressed for the last several years as a result of over-supply caused by, among other things, increased drilling in unconventional reservoirs, reduced economic activity associated with a recession and weather conditions. We expect natural gas prices to be depressed during the foreseeable future. Approximately 40% of our estimated net proved reserves are natural gas, and 49% of our production in 2010 was natural gas. A sustained reduction in natural gas prices could have an adverse effect on our results of operation and financial condition.

Our actual recovery of reserves may substantially differ from our proved reserve estimates. This Form 10-K contains estimates of our proved oil and gas reserves and the estimated future net cash flows from such reserves. These estimates are based upon various assumptions, including assumptions required by the SEC relating to oil and gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. The process of estimating oil and natural gas reserves is complex. This process requires significant decisions and assumptions in the evaluation of available geological, geophysical, engineering and economic data for each reservoir and is therefore inherently imprecise. Additionally, our interpretations of the rules governing the estimation of proved reserves could differ from the interpretation of staff members of regulatory authorities resulting in estimates that could be challenged by these authorities.

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. Additionally, reserves and future cash flows may be subject to material downward or upward revisions, based on production history, development drilling and exploration activities and prices of oil and natural gas. We incorporate many factors and assumptions into our estimates including:

- Expected reservoir characteristics based on geological, geophysical and engineering assessments;
- Future production rates based on historical performance and expected future operation investment activities;
- Future oil and gas prices and quality and locational differences; and
- Future development and operating costs.

Although we believe our assumptions are reasonable based on the information available to us at the time we prepare our estimates, our actual results could vary considerably from estimated quantities of proved natural gas and oil reserves (in the aggregate and for a particular geographic location), production, revenues, taxes and development and operating expenditures. Our policies and practices regarding internal controls over the recording of reserves are structured to objectively and accurately estimate our oil and gas reserve quantities and present values in compliance with the SEC's regulations and US GAAP. We provide information about our oil and gas properties, including production profiles, prices and costs, to our independent reserve engineer and they prepare their own estimates of the reserve attributable to our properties.

You should not assume that any present value of future net cash flows from our producing reserves contained in this Form 10-K represents the market value of our estimated oil and natural gas reserves. We base the estimated discounted future net cash flows from our proved reserves at December 31, 2010 on average 12-month prices and costs as of the date of the estimate. Actual future prices and costs may be materially higher or lower. Further, actual future net revenues will be affected by factors such as the amount and timing of actual development expenditures, the rate and timing of production, and changes in governmental regulations or taxes. At December 31, 2010, approximately 21% of the discounted present value of our estimated net proved reserves consisted of PUDs. PUDs represented 51% of total proved reserves by volume, and approximately 33% of our PUDs were attributable to our deepwater properties. Recovery of undeveloped reserves generally requires significant capital expenditures and successful drilling operations. Our reserve estimates include the assumption that we will make significant capital expenditures to develop these undeveloped reserves and the actual costs, development schedule, and results associated with these properties may not be as estimated. In addition, the 10% discount factor that we use to calculate the net present value of future net revenues and cash flows may not necessarily be the most appropriate discount factor based on our cost of capital in effect from time to time and the risks associated with our business and the oil and gas industry in general.

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. The high-rate production characteristics of our Gulf of Mexico properties subject us to high reserve replacement needs. In general, the volume of production from oil and gas properties declines as reserves are depleted. The decline rates depend on reservoir characteristics. Gulf of Mexico reservoirs tend to be recovered quickly through production with associated steep declines, while declines in other regions after initial flush production tend to be relatively low. Approximately 43% of our estimated proved reserves at December 31, 2010 and 49% of our production during 2010 were associated with our Gulf of Mexico, deep-water properties. Our reserves will decline as they are produced unless we acquire properties with proved reserves or conduct successful development and exploration drilling activities. Our future natural gas and oil production is highly dependent upon our level of success in finding or acquiring additional reserves at a unit cost that is sustainable at prevailing commodity prices. Without successful exploration or acquisition activities, our reserves, production and revenues will decline.

Exploring for, developing, or acquiring reserves is capital intensive and uncertain. We may not be able to economically find, develop, or acquire additional reserves, or may not be able to make the necessary capital investments if our cash flows from operations decline or external sources of capital become limited or unavailable. We cannot assure you that our future exploitation, exploration, development, and acquisition activities will result in additional proved reserves or that we will be able to drill productive wells at acceptable costs. 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 2010, approximately 62% of our daily production came from three of our properties in the Gulf of Mexico. Moreover, one property accounted for 35% of our production during this period. In addition, at December 31, 2010, approximately 43% of our total net proved reserves were located in two fields in the Gulf of Mexico. 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. We may seek 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.

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.

Our exploration and development drilling efforts and the operation of our wells may not be profitable or achieve our targeted returns. Exploration, development, drilling and production activities are subject to many risks, including the risk that commercially productive reservoirs will not be discovered. We may invest in property, including undeveloped leasehold acreage, which we believe will result in projects that will add value over time. However, we cannot guarantee that any leasehold acreage acquired by us will be profitably developed, that new wells drilled by us will be productive or that we will recover all or any portion of our investment in such leasehold acreage or wells. Drilling for oil and natural gas may involve unprofitable efforts, not only from dry wells but also from wells that are productive but do not produce sufficient net reserves to return a profit after deducting operating and other costs. In addition, wells that are profitable may not achieve our targeted rate of return. Our ability to achieve our target results are dependent upon the current and future market prices for oil and natural gas, costs associated with producing oil and natural gas and our ability to add reserves at an acceptable cost. We rely to a significant extent on 3-D seismic data and other advanced technologies in identifying leasehold acreage prospects and in conducting our exploration activities. The 3-D seismic data and other technologies we use do not allow us to know conclusively whether oil or natural gas is present or may be produced economically. The use of 3-D seismic data and other technologies also requires greater pre-drilling expenditures than traditional drilling strategies.

In addition, we may not be successful in controlling our drilling and production costs to improve our overall return. The cost of drilling, completing and operating a well is often uncertain and cost factors can adversely affect the economics of a project. We cannot predict the cost of drilling, and we may be forced to limit, delay or cancel drilling operations as a result of a variety of factors, including:

- unexpected drilling conditions;
- pressure or irregularities in formations;
- equipment failures or accidents and shortages or delays in the availability of drilling rigs and the delivery of equipment; and
- compliance with governmental requirements.

We may be unable to integrate successfully the operations of future acquisitions with our operations, and we may not realize all the anticipated benefits of these acquisitions. We intend to focus on producing property acquisitions that would preferably include undeveloped acreage. Integration of 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, and as such, assets we acquire may prove to be worth less than we paid because of uncertainties in evaluating recoverable reserves and potential liabilities. We are actively seeking to acquire additional acreage in Louisiana and Texas 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. Our recent growth is due significantly to acquisitions of producing properties and undeveloped and unevaluated leaseholds. We expect acquisitions may also contribute to our future growth. Successful acquisitions require an assessment of a number of factors, including estimates of recoverable reserves, exploration potential, future oil and natural gas prices, operating and capital costs and potential environmental and other liabilities. Such assessments are inexact and their accuracy is inherently uncertain. In connection with our assessments, we perform a review of the acquired properties which we believe is generally consistent with industry practices. However, such a review will not reveal all existing or potential problems. In addition, our review may not permit us to become sufficiently familiar with the properties to fully assess their deficiencies and capabilities. We do not inspect every well. Even when we inspect a well, we do not always discover structural, subsurface and environmental problems that may exist or arise. We are generally not entitled to contractual indemnification for preclosing liabilities, including environmental liabilities. Normally, we acquire interests in properties on an “as is” basis with limited remedies for breaches of representations and warranties. As a result of these factors, we may not be able to acquire oil and natural gas properties that contain economically recoverable reserves or be able to complete such acquisitions on acceptable terms.

There is competition for available oil and gas properties. Our competitors include major oil and gas companies, independent oil and gas companies and financial buyers. Some of our competitors may have greater and more diverse resources than we do. High commodity prices and stiff competition for acquisitions have in the past, and may in the future, significantly increase the cost of available properties. The increased competition and rising prices for available properties could limit or impede our ability to identify acquisition opportunities that are economic for a company our size and that are necessary to grow our reserves or replace reserves produced.

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.

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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.

If we experience any of these problems, it could affect well bores, platforms, gathering systems and processing facilities, which could adversely affect our ability to conduct operations. We could also incur substantial losses in excess of our insurance coverage as a result of:

- injury or loss of life;
- severe damage to and destruction of property, natural resources and equipment;
- pollution and other environmental damage;
- clean-up responsibilities;
- regulatory investigation and penalties;
- suspension of our operations; and
- repairs to resume operations.

Offshore operations are also subject to a variety of additional operating risks peculiar to the marine environment, such as capsizing, collisions and damage or loss from hurricanes or other adverse weather conditions. These conditions can cause substantial damage to facilities and interrupt production. As a result, we could incur substantial liabilities that could reduce or eliminate the funds available for development or leasehold acquisitions, or result in loss of equipment and properties.

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.

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 could negatively affect our ability 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. 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.

In particular, in the Haynesville Shale and other nonconventional shale plays, capacity may be limited and it may be necessary for new interstate and intrastate pipelines and gathering systems to be built.

Part of our strategy involves drilling in new or emerging shale formations using horizontal drilling and completion techniques. The results of our planned drilling program in these formations may be subject to more uncertainties than conventional drilling programs in more established formations and may not meet our expectations for reserves or production. The results of our drilling in new or emerging formations, such as the Haynesville Shale, are generally more uncertain than drilling results in areas that are developed and have established production. Because new or emerging formations have limited or no production history, we are less able to use past drilling results in those areas to help predict our future drilling results. Further, part of our drilling strategy to maximize recoveries from the Haynesville Shale involves the drilling of horizontal wells using completion techniques that have proven to be successful in other shale formations. Our experience with horizontal drilling in these areas to date, as well as the industry's drilling and production history, while growing, is limited. The ultimate success of these drilling and completion strategies and techniques will be better evaluated over time as more wells are drilled and production profiles are better established. Further, access to adequate gathering systems or pipeline takeaway capacity and the availability of drilling rigs and other services may be more challenging in new or emerging areas. If our drilling results are less than anticipated or we are unable to execute our drilling program because of capital constraints, access to gathering systems and takeaway capacity or otherwise, and/or natural gas and oil prices decline, our investment in these areas may not be as attractive as we anticipate and we could incur material writedowns of unevaluated properties and the value of our undeveloped acreage could decline in the future.

The loss of key personnel could adversely affect our ability to operate. We depend, and will continue to depend in the foreseeable future, on the services of our senior officers and other key employees, as well as other third-party consultants with extensive experience and expertise in evaluating and analyzing drilling prospects and producing oil and gas from proved properties and maximizing production from oil and natural gas properties. Our ability to retain our senior officers, other key employees and our third party consultants, none of whom are subject to employment agreements, is important to our future success and growth. The unexpected loss of the services of one or more of these individuals could have a detrimental effect on our business.

We may not be insured against all of the operating risks to which our business in exposed. In accordance with industry practice, we maintain insurance against some, but not all, of the operating risks to which our business is exposed. We cannot assure you that our insurance will be adequate to cover losses or liabilities. We experienced Gulf of Mexico production interruption in 2005, 2006 and 2007 from Hurricanes Katrina and Rita and in 2008 and 2009 from Hurricanes Gustav and Ike for which we had no production interruption insurance. Also, we cannot predict the continued availability of insurance at premium levels that justify its purchase. No assurance can be given that we will be able to maintain insurance in the future at rates we consider reasonable and may elect none or minimal insurance coverage. The occurrence of a significant event, not fully insured or indemnified against, could have a material adverse affect on our financial condition and operations.

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, including the ability to procure fracture stimulation services on wells drilled; and
- our ability to access pipelines, and the location of facilities used to produce and transport oil and natural gas production.

The adoption of derivatives legislation and regulations related to derivative contracts could have an adverse impact on our ability to hedge risks associated with our business. In 2009. the President signed into law the Dodd-Frank Wall Street Reform and Consumer Protection Act. Among other things, the act requires the Commodity Futures Trading Commission and the SEC to enact regulations affecting derivative contracts, including the derivative contracts we use to hedge our exposure to price volatility. We cannot predict the content of these regulations or the effect that these regulations will have on our hedging activities. Of particular concern, the act does not explicitly exempt end users (such as us) from the requirements to post margin in connection with hedging activities. While several Senators have indicated that it was not the intent of the act to require margin from end users, the exemption is not in the act. If the regulations ultimately adopted were to require that we post margin for our hedging activities, our hedging would become more expensive and we may decide to alter our hedging strategy. Additionally, it is possible that regulations, when finally adopted, in addition to increasing the expenses related to our hedging program may cause us to alter our hedging strategy.

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.

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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. On November 30, 2010, the EPA published its amendments to the greenhouse gas reporting rule to include onshore and offshore oil and natural gas production facilities and onshore oil and natural gas processing, transmission, storage and distribution facilities, which may include facilities we operate. Reporting of greenhouse gas emissions from such facilities will be required on an annual basis beginning in 2012 for emissions occurring in 2011.

Both houses of the United States Congress have actively considered legislation to reduce emissions of GHGs and almost one-half of the states have already taken legal measures to reduce GHG emission reduction levels that states sent out to achieve by specific time periods, often involving the planned development of GHG emission inventories and/or regional cap and trade programs. Most of these cap and trade programs work by requiring major sources of emissions or major producers of fuels to acquire and surrender emission allowances. The number of allowances available for purchase is reduced each year in an effort to achieve the overall GHG emission reduction goal. These allowances would be expected to escalate significantly in cost over time. The adoption and implementation of any legislation or regulatory programs imposing reporting obligations on, or limiting emissions of GHGs from, our equipment and operations could require us to incur costs to reduce emissions of GHGS 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. Hydraulic fracturing is used to stimulate production of hydrocarbons, particularly natural gas, from tight formations. The process involves the injection of water, sand and chemicals under pressure into formations to fracture the surrounding rock and stimulate production. The process is typically regulated by state oil and gas commissions but is not subject to regulation at the federal level. The EPA has commenced a study of the potential environmental impacts of hydraulic fracturing activities, with results of the study anticipated to be available by late 2012, and a committee of the U.S. House of Representatives is also conducting an investigation of hydraulic fracturing practices. Legislation has been introduced before Congress to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the fracturing process. In addition, some states have adopted, and other states are considering adopting, regulations that could restrict hydraulic fracturing in certain circumstances. For example, New York has imposed a de facto moratorium on the issuance of permits for high-volume, horizontal hydraulic fracturing until state-administered environmental studies are finalized, a draft of which must be published by June 1, 2011, followed by a 30-day comment period. Further, Pennsylvania has adopted a variety of regulations limiting how and where fracturing can be performed. If new laws or regulations that significantly restrict hydraulic fracturing are adopted, such legal requirements could make it more difficult or costly for us to perform hydraulic fracturing activities and thereby affect the determination of whether a well is commercially viable. In addition, if hydraulic fracturing is regulated at the federal level, our fracturing activities could become subject to additional permit requirements or operational restrictions and also to associated permitting delays and potential increases in costs. Such federal or state legislation could require the disclosure of chemical constituents used in the fracturing process to state or federal regulatory authorities who could then make such information publicly available. In addition, restrictions on hydraulic fracturing could reduce the amount of oil and natural gas that we are ultimately able to produce in commercial quantities.

Certain U.S. federal income tax preferences currently available with respect to oil and natural gas production may be eliminated as a result of future legislation. Among the changes contained in President Obama's Budget Proposal for Fiscal Year 2012 is the elimination of certain key U.S. federal income tax incentives currently available to oil and gas exploration and production. The President's budget proposes to eliminate certain tax preferences applicable to taxpayers engaged in the exploration or production of natural resources. Specifically, the budget proposes to repeal the deduction for percentage depletion with respect to wells, in which case only cost depletion would be available. It is unclear whether any such changes will be enacted or how soon any such changes could become effective. The passage of any legislation as a result of these proposals or any other similar changes in U.S. federal income tax laws could negatively affect our financial condition and results of operations.

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.

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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 effect 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

The Company's 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.

			Stock Price	
	2010		High	Low
First quarter	ended	March 31, 2010	$5.90	$1.40
Second quarter	ended	June 30, 2010	8.80	4.46
Third quarter	ended	September 30, 2010	6.72	3.54
Fourth quarter	ended	December 31, 2010	6.39	4.45
	2009			
First quarter	ended	March 31, 2010	$3.50	$0.93
Second quarter	ended	June 30, 2010	3.15	1.01
Third quarter	ended	September 30, 2010	2.43	1.37
Fourth quarter	ended	December 31, 2010	2.13	1.36

As of March 3, 2011 the Company had approximately 3,393 common stockholders of record.

The Company has never paid dividends on its common stock, and intends to retain its cash flow from operations for the future operation and development of its business. In addition, the Company's 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 2010, neither the Company nor any affiliated purchasers made repurchases of Callon's equity securities.

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, 2010 (securities amounts are presented in thousands).

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 compensation plans
Equity compensation plans approved by security holders	124	$ 11.46	754
Equity compensation plans not approved by security holders	74	6.44	27
Total	198	9.57	781

For additional information regarding the Company's benefit plans and share-based compensation expense, see Notes 9 and 10 to the Consolidated Financial Statements.

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Performance Graph

The following graph compares the yearly percentage change for the five years ended December 31, 2010, in the cumulative total shareholder return on the Company's Common Stock against the cumulative total return for the following:

- the Morningstar Group Index consisting of independent oil and gas drilling and exploration companies. Note that following Morningstar's acquisition of Hemscott, the Morningstar Group Index is replacing the Hemscott Industry and Market Index of SIC Group 123 (the "Hemscott Group Index"), which was included in the Company's performance graphs in prior filings. Consequently, both indexes have been included for comparative purposes during the transition to the Morningstar Group Index; and
- the New York Stock Exchange Market Index.

Company/Market/Peer Group	12/31/2005	12/31/2006	12/31/2007	12/31/2008	12/31/2009	12/31/2010
Callon Petroleum Company	$100.00	$85.16	$93.20	$14.73	$8.50	$33.54
NYSE Composite Index	$100.00	$120.47	$131.15	$79.67	$102.20	$115.88
Morningstar Group Index	$100.00	$94.73	$126.71	$47.87	$72.96	$68.36
Hemscott Group Index	$100.00	$118.43	$186.25	$83.39	$158.52	$149.20

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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, 2010 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.

	For the year ended December 31,				
	2010	2009	2008	2007	2006
Statement of Operations Data:	(In thousands, except per share amounts)				
Operating revenues:					
Oil and gas sales	$89,882	$101,259	$141,312	$170,768	$182,268
Medusa BOEMRE royalty recoupment	-	40,886	-	-	-
Total operating revenues	$89,882	$142,145	$141,312	$170,768	$182,268
Operating expenses:					
Non-impairment related operating expenses	$68,703	$68,692	$97,497	$114,418	$107,865
Impairment of oil and gas properties	-	-	485,498	-	-
Total operating expenses	$68,703	$68,692	$582,995	$114,418	$107,865
Income (loss) from continuing operations	21,179	73,453	(441,683)	56,350	74,403
Net income (loss)	8,386	54,419	(438,893)	15,194	40,560
Earnings (loss) per share ("EPS"):					
Basic	$0.29	$2.47	$(20.68)	$0.73	$1.43
Diluted	$0.28	$2.45	$(20.68)	$0.71	$1.28
Weighted average number of shares outstanding for Basic EPS	28,817	22,072	21,222	20,776	20,270
Weighted average number of shares outstanding for Diluted EPS	29,476	22,200	21,222	21,290	21,363
Statement of Operations Data:					
Net cash provided by operating activities	$99,942	$19,698	$89,054	$109,283	$135,484
Net cash used in investing activities	(59,738)	(43,189)	(4,511)	(215,791)	(166,901)
Net cash provided by (used in) financing activities	(26,092)	10,000	(120,667)	(157,862)	30,748
Balance Sheet Data:					
Oil and gas properties, net	$168,868	$130,608	$159,252	$681,706	$547,027
Total assets	218,326	227,991	266,090	792,482	625,527
Long-term debt (a)	165,504	179,174	272,855	392,012	225,521
Stockholder' equity (deficit)	15,810	(80,854)	(129,804)	287,075	281,363
Proved Reserves Data:					
Total Oil (MMBbls)	8,148	6,479	6,027	24,531	13,265
Total Gas (MMcf)	32,956	19,103	18,652	116,454	66,037
Total proved reserves (MBoe)	13,641	9,663	9,136	43,940	24,271
Present value of estimated future after-tax, net cash flows	$198,916	$135,921	$86,305	$1,133,989	$470,791

(a) Long-term debt includes a non-cash $27,543 deferred credit that will be amortized into earnings as a reduction to interest expense over the life of the 13% Senior Notes due 2016. See Note 6 for additional information.

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 using a 12-month pricing average 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 2 and 13 to the Consolidated Financial Statements for a description of the relevant accounting policy and the Company's oil and gas properties disclosures, respectively.

ITEM 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations

General

The following management’s discussion and analysis is intended to assist in understanding the principal factors affecting the Company’s results of operations, liquidity, capital resources and contractual cash obligations. This discussion should be read in conjunction with the accompanying audited consolidated financial statements, information about our business practices, significant accounting policies, risk factors, and the transactions that underlie our financial results, which are included in various parts of this filing.

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, and beginning in the latter part of 2008, we took steps to change our operational focus to lower risk, onshore exploration and development activities thereby reducing our reserve and production concentration in offshore properties.

Overview and Outlook

During 2010, Callon had net income and fully diluted earnings per share of $8.4 million and $0.28, respectively, compared to net income of $54.4 million and fully diluted earnings per share of $2.45, respectively for 2009. Prior year results included a $44.8 million royalty recoupment, plus $7.7 million interest, from the BOEMRE for royalties paid during 2009 and prior years. The Company’s earnings, and the drivers of these earnings, are discussed in greater detail within the “Results of Operations” section included below.

Also during 2010, Callon increased proved reserves by approximately 41%, increased Permian Basin oil production by 69%, brought online its first Haynesville gas well and diversified its net proved reserves with nearly 50% now being located onshore.

We made significant progress during 2010 towards our goal of strengthening our balance sheet and improving our liquidity, which better positions Callon for future growth. Significant financial achievements include:

- Including principal and interest through the repayment date, we received $52.7 million for recoupment of deepwater royalty payments made to the BOEMRE.
- The borrowing base of our Credit Facility was amended to provide for a $30 million borrowing base, representing a $10 million or 50% increase over the originally approved borrowing base. The underwriting bank approved the increase following its most recent borrowing base review based on the growth of the Company’s proved reserves, the collateral for the facility.
- We completed the redemption of the remaining $16.1 million outstanding of 9.75% Senior Notes (“Old Notes”) held by those note holders who did not participate in an exchange offered in teh fourth quarter of 2009. The redemption and the exchange of our Old Notes with 13% Senior Notes reduced by 25% the principal balance of our notes and extended the restructured notes’ maturity from 2010 to 2016 in exchange for a 3.25% increase in the coupon rate and equity consideration. Principal outstanding under the 13% Senior Notes due 2016 is approximately $138.0 million, a significant decrease from the $200 million principal formerly outstanding under the Old Notes. (See Note 6 and discussion below highlighting the planned early redemption of $31 million of 13% Senior Notes during March 2011)

During February 2011, the Company received $73.7 million in net proceeds through the public offering of 10.1 million shares of its common stock, which included the issuance of 1.1 million shares pursuant to the underwriters' over-allotment option. During March 2011, the Company intends to utilize approximately $35 million of the proceeds to redeem $31 million face value of its Senior Notes, plus the 13% call premium. The remaining proceeds from the offering are intended to fund a portion of our 2011 capital budget and for general corporate purposes, including possible future acquisitions.

Our success in these areas allows us to continue executing on our strategy to shift our operational focus from the offshore Gulf of Mexico to developing longer life, lower risk onshore properties. Our Permian Basin and Haynesville Shale onshore properties along with the cash flow from our Gulf of Mexico operations have already begun to re-shape our portfolio and outlook, and we believe that we are well positioned to continue diversifying our portfolio by building profitable growth opportunities onshore. During 2010, we began to develop the properties we acquired during late 2009. This 2010 development resulted in a 41% increase in total proved reserves, of which 50% were onshore.

- Onshore – Permian Basin

During the fourth quarter of 2009, we acquired interests in properties producing from the Permian Basin's Wolfberry and other formations in Crockett, Ector, Midland and Upton Counties, Texas. The acquisition included year-end proved reserves of 1.6 MMBoe, 22 existing wells producing approximately 325 Boe/d and upside from a multi-year inventory of drilling opportunities. We operate substantially all of the production and development of these properties. We currently own approximately 8,800 net acres in the Permian Basin with approximately 80% prospect for the Wolfberry.

During 2010, we drilled gross 20 wells in the Permian Basin targeting the Wolfberry, and placed on production 11 wells at a total cost of approximately $32.0 million. As a result of our 2010 development drilling activity, our net production has increased from 325 net Boe/d at the end of 2009 to 550 net Boe/d as of December 31, 2010, somewhat lower than our original expectations of 750 net Boe/d. The lower production relates primarily to delays in receiving fracture stimulation services, discussed below, for which there is increased demand in the area at the present time. Beyond 2010, and based on our current acreage holdings, our Permian acreage has the potential for an additional 132 wells based on 40-acre spacing.

As of December 31, 2010, we had nine wells awaiting fracture stimulation with the expectation that we will continue to build an inventory of wells waiting on fracture stimulation until the service organization builds additional capacity to handle industry requirements. As of March 1, 2011, three wells that were awaiting fracture stimulation as of December 31, 2010 have since been brought online. Early in 2011, we entered into an agreement with our fracture stimulation service provider providing for a minimum of three well stimulations per month in 2011. Either party to the agreement may cancel the agreement without penalty with at least 30 days notice. We expect to fracture stimulate three additional wells during the first quarter of 2011, and expect that our remaining year-end 2010 inventory of wells awaiting stimulation will be serviced by the second quarter of 2011. We plan to drill up to 44 gross wells during 2011, of which three had been drilled and two were in-process as of March 1, 2011.

In addition, during 2010 we have increased our interest in the East Bloxom Development Area, located in Upton County, from an average 47% working interest to a 100% working interest through a number of small acquisitions and farm-ins. As a result, we now control the activity in three development areas encompassing 11 sections.

- Onshore – Shale Gas (Haynesville Shale)

Also during the late 2009, we acquired a 69% working interest in a 624-acre unit in the heart of the Haynesville Shale play in Bossier Parish, Louisiana. Our multi-year development plan for this property includes drilling and operating a total of seven gross or five net horizontal wells. The first of these wells was spud during June 2010, completed and placed on production in September 2010 and was producing, at a restricted rate, approximately 6,500 Mcfe/d as of December 31, 2010. The well cost approximately $10.9 million net to Callon, which included additional site development work for future wells. We have no remaining drilling obligations in our Haynesville Shale position, and currently plan to mobilize a rig to the area once natural gas prices warrant continued development of the remaining six planned horizontal wells. The Company currently owns approximately 430 net acres in the Haynesville Shale.

Also highlighting the continued successful execution of our long-term strategy and as a result of an increase in our market capitalization to an amount above the minimum required threshold, on April 23, 2010 the New York Stock Exchange ("NYSE") removed Callon from its "Watch List" and affirmed that we are now considered a "company back in compliance" with the NYSE's quantitative continued listing standards.

Our onshore properties along with the strong cash flow from our Gulf of Mexico operations have strengthened our portfolio and outlook. We believe 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;
- Allocation of capital expenditures to acquire producing properties;
- Natural field decline in the deepwater Gulf of Mexico and Gulf Coast areas of our 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.

Deconsolidation of Callon Entrada

During 2010 we adopted the newly issued accounting standard issued by the FASB in September 2009, which significantly modified our consolidated financial statements. Upon adoption, we reevaluated our interest in Callon Entrada, and based on the evaluation performed, we concluded that a variable interest entity (“VIE”) reconsideration event had taken place. Our reconsideration analysis resulted in the determination that Callon Entrada is a VIE for which we are not the primary beneficiary. Consequently, effective January 1, 2010, Callon Entrada was deconsolidated from our consolidated financial statements. The deconsolidation of Callon Entrada resulted in the removal of approximately $1.8 million of current assets, $2.0 million of current liabilities, $30.3 million of deferred tax assets, $30.3 million of tax valuation allowance and approximately $84.8 million of non-recourse debt and the related obligation for the cumulative amount of interest. Retained earnings increased by $85.1 million as a cumulative effect of change related to this accounting standard. No gain was recognized in the statement of operations. For additional information regarding the deconsolidation of Callon Entrada, see Note 3, Deconsolidation of Callon Entrada, included in Item II, Part 8 of this filing.

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. Cash and cash equivalents increased by $13.8 million during 2010 to $17.4 million compared to $3.6 million at December 31, 2009. The increase is primarily attributable to an $80.2 million increase in cash flows from operations, which included production increases from our newly acquired properties and higher realized, average commodity prices on an equivalent basis, and the receipt of the previously discussed $52.7 million BOEMRE royalty recoupment and related interest. These increases were partially offset by production declines on some legacy properties, a $16.5 million increase in cash used in investing activities and a $36.1 million increase in cash used in financing activities.

During 2010, we amended our Senior Secured Credit Agreement to include Regions Bank as the sole arranger and administrative agent. The third amended and restated senior secured credit agreement (“the Credit Facility”), which matures on September 25, 2012, provides for a $100 million facility and has a current borrowing base of $30 million, which represents a $10 million or 50% increase over the original $20 million borrowing base. Regions Bank approved the increase following its fourth quarter 2010 redetermination review. The bank performs its redetermination reviews on a semi-annual basis. The Credit Facility bears interest at 4% above a defined base rate and in no event will the interest rate be less than 6%. As of December 31, 2010, the interest rate on the facility was 6%. In addition, a commitment fee of 0.5% per annum on the unused portion of the borrowing base, is payable quarterly. Simultaneously with the execution of the third amended and restated senior secured credit agreement, we repaid the $10 million then outstanding under the second amended and restated senior secured credit agreement. No amounts were outstanding under the amended facility as of December 31, 2010.

During the second quarter of 2010, we redeemed the remaining $16.1 million outstanding of our Old Notes, leaving only $138.0 million of the 13% Senior Notes outstanding at December 31, 2010. Following the previously discussed February 2011 equity offering from which the company received net proceeds of $73.7 million through the issuance of 10.1 million shares of its common stock, the Company intends to redeem during March 2011 $31 million of the 13% Senior Notes for approximately $35 million inclusive of the $4 million call premium. The remaining proceeds from the offering are to fund a portion of its 2011 capital budget and for general corporate purposes, including possible future acquisitions.

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2011 Budget and Capital Expenditures

For 2011, we designed a flexible capital spending program that can be funded from cash on hand, including the proceeds from the recent equity offering, and cash flows from operations. We believe these resources along with our Credit Facility, if needed, will be adequate to meet our capital, interest payments, and operating requirements for 2011. 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.

Our preliminary base capital program includes further development of our Permian Basin crude oil assets, with plans to drill approximately 44 additional gross oil wells during 2011. Our 2011 capital budget approximates $107 million, of which 81% is dedicated to our growth strategy, and also includes plugging and abandonment, capitalized interest and certain overhead costs related to acquiring, exploring and developing our oil and gas properties. Components of the 2011 capital budget include:

Permian Basin / Wolfberry development	$77
Leasehold related	10
Gulf of Mexico plugging and abandonment and maintenance capital expenditures	8
Capitalized interest and general and administrative costs	12
Total projected 2011 capital expenditures budget	$107

Should we identify an attractive strategic opportunity or acquisition, in addition to our available cash including the proceeds from the recent equity offering , we have a $30 million borrowing base available under our Credit Facility.

The following table includes the Company's contractual obligations and purchase commitments as of December 31, 2010, at which date the Company had no product delivery commitments:

	Payments due by Period				
Contractual Obligation & Purchase Commitments	Total	< 1 Year	1 - 3 Years	3 - 5 Years	>5 Years
13% Senior Notes	$137,961	-	-	$137,961	-
Office space lease commitments	2,972	26	458	684	1,804
Medusa Oil Pipeline Throughput Commitment	101	39	35	27	-
Total	$141,034	$65	$493	$138,672	$1,804

Summary cash flow information is provided as follows:

Operating Activities. For the year ended December 31, 2010, net cash provided by operating activities was $99.9 million, an $80.2 million or 407% increase from net cash provided by operating activities of $19.7 million for the same period in 2009. The increase in net cash provided by operating activities was primarily attributable to receipt of the $52.7 million BOEMRE royalty recoupment including interest, production increases from our onshore properties and higher commodity prices on an equivalent basis, partially offset by production declines on some legacy properties.

Investing Activities. For the year ended December 31, 2010, net cash used in investing activities was $59.7 million as compared to $43.2 million for the same period in 2009. The $16.5 million increase, primarily attributable to an increase in capital expenditure spending, relates to drilling 20 wells in the Permian Basin properties and one well in the Haynesville Shale property. These increases were partially offset by the wind-down costs paid in 2009 for Callon Entrada with no similar costs paid during 2010.

Financing Activities. For the year ended December 31, 2010, net cash used in financing activities was $26.1 million compared to cash provided of $10.0 million for the same period in 2009. The 2010 expenditures related to the redemption of the $16.1 million remaining Old Notes and to the repayment of $10 million outstanding borrowings under the Credit Facility simultaneous with the amendment to include Regions Bank as the sole arranger and administrative agent.

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Results of Operations

The following table sets forth certain unaudited operating information with respect to the Company's oil and gas operations for the periods indicated:

	For the year ended December 31,						
	2010	2009	$ Change	% Change	2008	$ Change	% Change
Net production:							
Oil (MBbls)	859	1,012	(153)	(15)%	942	70	7 %
Gas (MMcf)	4,892	5,740	(848)	(15)%	5,839	(99)	(2)%
Total production (MBoe)	1,674	1,969	(295)	(15)%	1,915	54	3 %
Average daily production (Boe)	4,587	5,394	(807)	(15)%	5,247	147	3 %
Average realized sales price (a):							
Oil (Bbl)	$ 75.97	$ 73.00	$ 2.97	4 %	$ 88.07	$ (15.07)	(17)%
Gas (Mcf)	5.04	4.78	0.26	5 %	9.99	(5.21)	(52)%
Total (Boe)	53.69	51.44	2.25	4 %	73.79	(22.35)	(30)%
Oil and gas revenues (in thousands):							
Oil revenue	$ 65,243	$ 73,842	$ (8,599)	(12)%	$ 82,963	$ (9,121)	(11)%
Gas revenue	24,639	27,417	(2,778)	(10)%	58,349	(30,932)	(53)%
Total	$ 89,882	$ 101,259	$ (11,377)	(11)%	$ 141,312	$ (40,053)	(28)%
Additional per Boe data:							
Sales price	$ 53.69	$ 51.44	$ 2.25	4 %	$ 73.79	$ (22.35)	(30)%
Lease operating expense	(10.58)	(9.37)	(1.21)	13 %	(10.03)	0.66	(7)%
Operating margin	$ 43.11	$ 42.07	$ 1.04	2 %	$ 63.76	$ (21.69)	(34)%

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

Average NYMEX oil	$ 79.52	$ 61.80	$ 17.72	29 %	$ 99.67	$ (37.87)	(38)%

price							
Basis differential and quality adjustments	(2.39)	(4.64)	2.25	(48)%	(1.15)	(3.49)	303 %
Transportation	(1.16)	(1.32)	0.16	(12)%	(1.15)	(0.17)	15 %
Hedging	-	17.16	(17.16)	(100)%	(9.30)	26.46	(285)%
Average realized oil price	$ 75.97	$ 73.00	$ 2.97	4 %	$ 88.07	$ (15.07)	(17)%
Average NYMEX gas price	$ 4.40	$ 4.17	$ 0.23	6 %	$ 8.91	$ (4.74)	(53)%
Basis differential and quality adjustments	0.51	0.28	0.23	82 %	1.19	(0.91)	(76)%
Hedging	0.13	0.33	(0.20)	(61)%	(0.11)	0.44	(400)%
Average realized gas price	$ 5.04	$ 4.78	$ 0.26	5 %	$ 9.99	$ (5.21)	(52)%

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Item 7 – Management's Discussion and Analysis of Financial Condition and Results of Operations (continued)

Revenues

The following tables are intended to reconcile the change in crude oil, natural gas and total revenue by reflecting the effect of changes in volume, changes in the underlying commodity prices and the impact of our hedge program (in thousands):

	Crude Oil	Natural Gas	Total
Revenues for the year ended December 31, 2007	$71,891	$98,877	$170,768
Volume decrease	(8,183)	(52,091)	(60,274)
Price increase	28,015	12,213	40,228
Impact of hedges decrease	(8,760)	(650)	(9,410)
Net increase (decrease) in 2008	11,072	(40,528)	(29,456)
Revenues for the year ended December 31, 2008	$82,963	$58,349	$141,312
Volume increase (decrease)	6,165	(989)	5,176
Price decrease	(32,639)	(31,832)	(64,471)
Impact of hedges increase	17,353	1,889	19,242
Net decrease in 2009	(9,121)	(30,932)	(40,053)
Revenues for the year ended December 31, 2009	$73,842	$27,417	$101,259
Volume decrease	(11,164)	(4,050)	(15,214)
Price increase	2,556	649	3,205
Impact of hedges increase	9	623	632
Net decrease in 2010	(8,599)	(2,778)	(11,377)
Revenues for the year ended December 31, 2010	$65,243	$24,639	$89,882

Total Revenue

Total oil and gas revenues of $89.9 million for the year ended December 31, 2010 were approximately $11.4 million, or 11%, less than $101.3 million for the same period of 2009. The largest contributors to the year-over-year decline included a 15% decline in production on an equivalent basis, partially offset by a 4% increase in average realized prices. Compared to 2009, the decline in production on an equivalent basis during 2010 was primarily driven by normal and expected declines from our legacy properties and damage to one of our Gulf of Mexico gas field production facilities. These declines were partially offset by new production from our Permian Basin and Haynesville Shale properties.

Total 2009 oil and gas revenues of $101.3 million decreased 28% or $40 million from $141.3 million in 2008 primarily due to lower oil and gas average realized sales prices. As reflected in the table above, hedge related revenues and a 3% increase in total production on an equivalent basis partially offset the decline in revenue for 2009 compared to 2008.

Oil Revenue

Crude oil revenues of $65.2 million for the year ended December 31, 2010 were approximately $8.6 million, or 12%, less than oil revenues of $73.8 million for the same period of 2009. The largest contributor to the decline was a 15% decrease in production, partially offset by a 4% increase in the average realized oil price. In addition to normal and expected production declines, volumes declined primarily due to our working interest in Habanero #1 decreasing from 25% to 11.25% in June 2009 following the payout of a sidetrack on this well. The payout was associated with a third quarter 2007 sidetrack of the #1 well for which the operator elected to non-consent. These declines were partially offset by production from our newly drilled and completed wells on the Permian Basin properties that we acquired during the fourth quarter of 2009.

Oil production during 2009 totaled 1.0 million barrels and generated $73.8 million in revenues compared to 0.9 million 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 BOEMRE royalty recoupment, described in Note 16, for the Medusa Field.

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Gas Revenue

Natural gas revenues of $24.6 million for the year ended December 31, 2010 were approximately $2.8 million, or 10%, less when compared to gas revenues of $27.4 million for the same period of 2009. The largest contributor to the decline was a 15% decrease in production, partially offset by a 5% increase in the average realized sales price of gas. The largest contributor to the decline in production was the shut-in of the East Cameron #2 well, which was shut-in during January 2010 due to damage resulting from a fire. Production at the East Cameron #2 well was restored during the latter part of the fourth quarter of 2010 following the completion of the necessary repairs and BOEMRE inspections. Also contributing to the production decrease was the Habanero #1 well reversionary interest discussed above in the oil revenue analysis, while the remaining decrease in production was due to normal and expected declines from our legacy properties and production suspensions related to well recompletions and BOEMRE recompletion work approval such as at our Mobile Block 864 well. Offsetting these declines are increases from our Permian Basin properties discussed above, and production from our first Haynesville gas well, which was placed on production during September 2010.

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.

Operating Expenses

	For the year ended December 31,								
					Year Change				
	2010	Per Boe	2009	Per Boe			$		%
Lease operating expenses	17,712	$10.58	$18,447	$9.37	$(735	)	(4	)%	
Depreciation, depletion and amortization	31,805	19.00	33,443	16.99	(1,638	)	(5	)%	
General and administrative, net	16,507	9.86	13,355	6.78	3,152		24	%	
Accretion expense	2,446	1.46	3,149	1.60	(703	)	(22	)%	
Acquisition expense	233	0.14	298	0.15	(65	)	(22	)%	
Total operating expenses	68,703		$68,692						

	For the year ended December 31,							
					Year Change			
	2009	Per Boe	2008	Per Boe			$	%
Lease operating expenses	18,447	$9.37	$19,208	$10.03	$(761	)	(4	)%
Depreciation, depletion and amortization	33,443	16.99	64,054	33.45	(30,611	)	(48	)%
General and administrative, net	13,355	6.78	9,565	4.99	3,790		40	%
Accretion expense	3,149	1.60	4,172	2.18	(1,023	)	(25	)%
Acquisition expense	298	0.15	-	-	298		100	%
Derivative expense	-	-	498	0.26	(498	)	(100	)%
Impairment of oil and gas properties	-	-	485,498	253.50	(485,498	)	(100	)%
Total operating expenses	68,692		$582,995					

Lease Operating Expenses

For the year ended December 31, 2010, lease operating expenses (“LOE”) decreased 4% to $17.7 million compared to $18.4 million for the same period in 2009. The primary contributor to the reduction in LOE was normal and expected declines in production in addition to, as previously discussed above in the oil revenue comparative analysis, the reduction in our working interest in Habanero #1 well following the payout of a sidetrack on this well. Partially offsetting these decreases, LOE increased related to our acquisition of the Permian Basin properties and a modest increase in insurance rates due to adding additional coverage to our program designed to better protect the Company from damage caused by severe weather.

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

For the year ended December 31, 2010, DD&A decreased approximately $1.7 million or 5% to $31.8 million compared to $33.4 million for the same period of 2009. Production declines account for nearly all of the decrease, while a rate increase partially offset the production volume decreases.

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.

General and Administrative, net of amounts capitalized

For the year ended December 31, 2010, G&A expenses, net of amounts capitalized, increased $3.2 million or 24% to $16.5 million from $13.4 million for the same period of 2009. Our performance-based incentive program runs from April to March, and adjustments to our accruals are recorded during the first quarter upon completion of the program and evaluation by the Company's Compensation Committee of the Board of Directors. During the first quarter of 2009, we recorded a 75% reduction in incentive-based compensation related to our actual 2008 results. These results, which were negatively affected by the decline in oil and gas prices, the abandonment of the Entrada project and worsening broader economic conditions, were lower than the performance goals set for fiscal year 2008. Conversely, the increase experienced during 2010 relates primarily to a 21% increase in incentive-based compensation related to exceeding performance goals set for fiscal year 2009. Also contributing to the increase are (1) a valuation adjustment to mark to fair value a portion of our share-based awards that will vest in the future which are accounted for as a liability, (2) additional employee-related costs, including non-recurring early retirement expenses, (3) costs associated with adding new employees, including relocation and related costs, and (4) higher legal costs and other charges related to an arbitration hearing involving a dispute with our joint interest partner in the Entrada development project. Partially offsetting the increases are $2.2 million of expenses related to staff reductions incurred during the second quarter of 2009 for which no similar charge was recorded during 2010.

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.

Accretion Expense

For the year ended December 31, 2010, accretion expense decreased $0.7 million or 22% to $2.4 million from $3.1 million incurred during the same period of 2009. The Company's accretion expense decreases as its ARO decreases. As of December 31, 2010, our average ARO liability for 2010 of $15.0 million was significantly lower than our average ARO liability of $27.0 million for the same period in 2009. Similarly, 2009 accretion expense of $3.1 million declined compared to 2008 accretion expense of $4.2 million, due to a lower average ARO liability in 2009 compared to the 2008 liability. For additional information regarding the company's oil and gas properties and the related ARO, see Notes 13 and 14 included to the Consolidated Financial Statements.

Impairment of Oil and Gas Properties

No impairments of oil and gas properties were recorded during either 2010 or 2009. 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. For additional information, see Note 13 to the Consolidated Financial Statements.

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Other (Income) Expense

	For the year ended December 31,					Year Change	
	2010	2009	$ Change	% Change	2008	$ (Dollars)	% (Percent)
Interest expense	$13,312	$19,089	$(5,777)	(30)%	$23,986	$(4,897)	(20)%
Callon Entrada non-recourse credit facility interest expense (See Note 3)	-	7,072	(7,072)	(100)%	2,719	4,353	160%
Loss on early extinguishment of debt	339	-	339	100%	11,871	(11,871)	(100)%
9.75% Senior Notes restructuring expenses	-	1,024	(1,024)	(100)%	-	1,024	100%
Interest on BOEMRE royalty recoupment	(91)	(7,681)	7,590	(99)%	-	(7,681)	(100)%
Other (income) expense	(166)	190	(356)	(187)%	(1,379)	1,569	(114)%
Total other (income) expenses	$13,394	$19,694			$37,197		
Income tax benefit	(174)	-	(174)	100%	$39,725	$(39,725)	(100)%
Equity in earnings of Medusa Spar LLC	$427	$660	$(233)	(35)%	262	(262)	152%

Interest Expense

For the year ended December 31, 2010, interest expense decreased $5.8 million or 30% to $13.3 million compared to $19.1 million for the same period of 2009. The decrease was primarily due to the $3.7 million amortization of our deferred credit related to the Senior Notes, which is recorded as a decrease to interest expense. Also reducing interest expense during 2010 was a decrease in the amount of discount amortization recognized related to our Old Notes, 92% of which were exchanged during 2009. Further, the remaining $16.1 million of outstanding Old Notes that did not participate in the exchange were later redeemed on April 30, 2010 resulting in approximately $1.1 million of interest expense savings during 2010 as compared to 2009.

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. For additional information, see Note 6 to the Consolidated Financial Statement.

Callon Entrada Non-Recourse Credit Agreement Interest Expense

As discussed in Note 3 to the Consolidated Financial Statements and as a result of the deconsolidation of Callon Entrada effective January 1, 2010, during 2010 we incurred no expense related to this non-recourse credit facility.

For the years ended December 31, 2009 and 2008, we incurred interest expense under the Callon Entrada credit agreement 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.

Loss on Early Extinguishment of Debt

For the year ended December 31, 2010, the loss on early extinguishment of debt was $0.34 million, though no similar expense was incurred during 2009. The $0.34 million related to the 1% call premium, equal to $0.16 million, paid to redeem the remaining $16.1 million of Old Notes not exchanged during the restructuring of the Old Notes, plus $0.18 million for the accelerated amortization of the Old Notes' remaining discount and debt issuance costs.

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. For additional information, see Note 6 to the Consolidated Financial Statements.

9.75% Senior Notes Restructuring Expense

During the fourth quarter of 2009 and following the successful exchange of our Old Note for the 13% Senior Notes, we incurred $1.0 million of financing cost related to consultant and legal expenses. For additional information, see Note 6 to the Consolidated Financial Statements.

Interest on BOEMRE Royalty Recoupment

Following a court ruling against the BOEMRE resulting from several royalty payment-related court cases brought by another oil and gas company, during 2009 we filed for a $44.8 million royalty recoupment for royalty payments previously made on inception-to-date our production from Medusa field. Consequently, the Company also recorded a related $7.7 million interest receivable for the interest owed on the amounts paid. During the first quarter of 2010, the Company received both the recoupment principal and interest. In addition, the Company is no longer required to make any future royalty payments to the BOEMRE related to its Medusa production. For additional information, see Note 16 included to the Consolidated Financial Statements.

Income Tax Expense

For the years ended December 31, 2010 and 2009, income tax expense was negligible despite earning pre-tax income of approximate $7.8 million and $53.8 million, respectively. Income tax expense remained immaterial due to adjustments made to our deferred tax asset valuation. During 2010, we recorded a $0.2 million tax benefit related to recovery of alternative minimum taxes paid during prior years.

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. For additional information, see Note 12 to the Consolidated Financial Statements.

Off-Balance Sheet Arrangements

The Company holds a 10% ownership interest in Medusa Spar LLC ("LLC"), which is accounted for under the equity method of accounting for investments. The LLC owns a 75% undivided ownership interest in the deepwater spar production facilities at the Company's Medusa Field in the Gulf of Mexico. The LLC earns a tariff based upon production volume throughput from the Medusa area. Callon is obligated to process through the spar production facilities its share of production from the Medusa Field and any future discoveries in the area. The balance of Medusa Spar LLC is owned by Oceaneering International, Inc. and Murphy Oil Corporation.

Summary of Significant Accounting Policies

Property and Equipment

The Company utilizes the full-cost method of accounting for its 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 capitalized 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 the Company makes estimates based on its assumptions of future events that could change. These estimates are described below.

Depreciation, Depletion and Amortization (DD&A) of Oil and Gas Properties

The Company calculates depletion by using the depletable base, equal to the net capitalized costs in our full-cost pool plus estimated future development costs, and the 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 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 the production of oil and gas or general corporate overhead;

- costs associated with unevaluated properties, those lacking proved reserves, 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 the Company determines these costs have been impaired. The Company's determination that a property has or has not been impaired (which is discussed below) requires 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 (see also the discussion below regarding 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. The Company uses assumptions based on the latest geologic, engineering, regulatory and cost data available to us to estimate these amounts. However, the estimates made are subjective and may change over time. The Company's estimates of future development costs are reviewed at least annually and 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, the Company estimates the proved reserves quantities at the beginning of each accounting period. For each Mcfe produced during the period, the Company records 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 the Company uses 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 method of accounting, the Company compares, at the end of each financial reporting period, the present value of estimated future net cash flows from proved reserves (excluding cash flows related to estimated abandonment costs), to the net capitalized costs of proved oil and gas properties net of related deferred taxes. The Company refers to this comparison as a "ceiling test." If the net capitalized costs of proved oil and gas properties exceed the estimated discounted (at 10%) future net cash flows from proved reserves, the Company is required to write-down the value of its oil and gas properties to the value of the discounted cash flows. Estimated future net cash flows from proved reserves are based on a twelve-month average pricing assumption. Given the volatility of oil and gas prices, it is reasonably possible that the Company's estimates 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 Notes 2 and 13 for additional information regarding the Company's oil and gas properties.

Estimating Reserves and Present Value of Estimated Future Net Cash Flows

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 the Company can sell its 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; and

- the costs to develop and produce the Company's reserves and the costs to dismantle its production facilities when reserves are depleted. These costs are likely to change over time, but the Company is 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.

Changes in these prices and/or costs will affect the present value of estimated future net cash flows more than the estimated quantities of oil and gas reserves for the Company's properties that have relatively short productive lives.

In addition, the process of estimating proved oil and gas reserves requires that the Company's 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.

Unproved Properties

Costs, including capitalized interest, associated with properties that do not have proved reserves are excluded from the depletable base, and 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, the Company is required to determine whether its unproved properties are impaired and, if so, include the costs of such properties in the depletable base. The Company determines whether an unproved property is impaired by periodically reviewing its exploration program on a property-by-property basis. This determination may require the exercise of substantial judgment by management.

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-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 14 for additional information.

Derivatives

To manage oil and gas price risk on a limited amount of its planned future production, the Company periodically uses derivative financial instruments. The Company does not use these instruments for trading purposes. Settlement of derivative contracts are generally based on the difference between the contract price and prices specified in the derivative instrument and a NYMEX price or other cash or futures index price.

The Company's derivative contracts, all of which are accounted for as cash flow hedges, are recorded at fair market value on its consolidated balance sheet under the caption "Fair Market Value of Derivatives". 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. Changes in fair value recorded through other comprehensive income (loss), net of tax, in stockholders' equity. The cash settlements on these contracts are recorded in the Statement of Operations 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). For additional information regarding derivatives and their fair values, see Notes 7 and 8 to the Consolidated Financial Statements.

Subsequent Events.

For additional information regarding subsequent events, see Note 19 included in Part II, Item 8 of this filing.

Equity Offering and Announced Senior Notes Redemption

As previously discussed above in the Results of Operations and Liquidity discussions, during February 2011, the Company received $73.7 million in net proceeds through the public offering of 10.1 million shares of its common stock, which included the issuance of 1.1 million shares pursuant to the underwriters' over-allotment option. Immediately following the completion of the equity offering, the Company provided the public notice required by the terms of the Senior Notes to call $31.0 million of face value of the Notes. The Company expects to complete the redemption of these notes by March 19, 2011, which will result in a gain on the early extinguishment of debt of approximately $2.0 million. The gain represents the difference between the $35.0 million paid for $37.0

million carrying value of the Notes, which included the $31.0 million face value of the notes plus $6.0 million of accelerated deferred credit amortization, offset by the $4.0 million 13% call premium required by the terms of the call option.

Arbitration Results

Prior to abandonment of the Entrada project, the Company's joint interest owner in the Entrada Project 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. Following its partner's failure to fund these requests, the 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 joint interest partner also failed to fund its working interest share of a settlement payment to terminate a drilling contract for the Entrada Project. The Company and its joint interest partner in the Entrada project arbitrated the matter during 2010. During February, 2011, the arbitration panel reviewing the Company's claims against the joint interest owner delivered its final decision in which it ruled that the company was not entitled to recover any damages. The Company determination that the arbitration ruling represented a recognizable subsequent event, and as such, recorded a charge as of December 31, 2010 to write off its $6.6 receivable related to certain joint interest billings not being recovered from a joint interest partner. Under the full cost method of accounting, these costs are capitalized to the Company's full cost pool.

Recent Accounting Standards

For a discussion of recently issued accounting standards, see Note 2 to the Consolidated Financial Statements.

ITEM 7A. Quantitative and Qualitative Disclosures about Market Risks

The primary objective of the following information is to provide forward-looking quantitative and qualitative information about our exposure to market risk. The term market risk relates to the risk of loss arising from adverse changes in oil and natural gas prices and interest rates. The disclosures are not meant to be precise indicators of expected future losses, but rather indicators of reasonably possible losses. The forward-looking information provides indicators of how the Company views and manages its ongoing market risk exposures.

Commodity Price Risk

The Company's revenues, earnings, cash flow, capital investments and, ultimately, future rate of growth are highly dependent on the prices we receive for our crude oil and natural gas, which have historically been very volatile due to unpredictable events such as economical growth or retraction, weather and climate, changes in supply and government actions. Oil and natural gas price declines and volatility could adversely affect the Company's revenues, cash flows and profitability. Price volatility is expected to continue. Based on projected annual sales volumes for 2011, excluding production from 2011 exploratory drilling and the effects of the Company's hedging program, a 10% decline in the prices we receive for our crude oil and natural gas production would result in an approximate $10.6 million reduction of our revenues.

While the Company does not enter into derivative transactions for speculative purposes, in order to limit its exposure to this risk, the Company most often utilizes 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 Callon, and if the price rises above the ceiling, Callon pays the difference to the counter-party.

The Company may also enter into derivative financial instruments including fixed price "swaps." These swaps reduce our exposure to decreases in commodity prices, while simultaneously limiting the benefit the Company might otherwise have received from any increases in commodity prices. Similarly, the Company's derivatives policy also allows Callon to, at its discretion, 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 the Callon.

During 2010, all of the Company's derivative positions were designated as hedges for accounting purposes, though the Company has the discretion not to designate its hedges as such. For additional information, see Note 7 to the Consolidated Financial Statements for a description of our hedged position at December 31, 2010.

Interest Rate Risk

On December 31, 2010, all of the Company's debt, consisting entirely of its 13% Senior Notes, had fixed interest rates. The Company's revolving credit facility with Regions Bank includes a variable interest rate, and as such fluctuates based on short-term interest rates. Although the Company had no borrowings outstanding at December 31, 2010 under its revolving credit facility, were the Company to fully draw its available $30 million borrowing base at the beginning of the year, a 100 basis point change in the variable interest rate would increase the Company's annual interest expense by $0.3 million. For additional information, see Note 6 to the Consolidated Financial Statements additional information regarding the Company's credit facility and other borrowings at December 31, 2010.

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ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

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, 2010 and 2009, 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, 2010. 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, 2010 and 2009, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2010, in conformity with U.S. generally accepted accounting principles.

As discussed in Note 2 to the financial statements, effective January 1, 2010, the Company changed its accounting for its subsidiary, Callon Entrada Company, as a result of adopting the amended accounting pronouncement related to the consolidation of variable interest entities. 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, 2010, 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 14, 2011, expressed an unqualified opinion thereon.

/s/Ernst & Young LLP

New Orleans, Louisiana
March 14, 2011

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

	December, 31 2010	December, 31 2009
ASSETS		
Current assets:		
Cash and cash equivalents	$17,436	$3,635
Accounts receivable	10,728	20,798
Accounts receivable - BOEMRE royalty recoupment	-	51,534
Fair market value of derivatives	-	145
Other current assets	2,180	1,572
Total current assets	30,344	77,684
Oil and gas properties, full-cost accounting method:		
Evaluated properties	1,316,677	1,593,884
Less accumulated depreciation, depletion and amortization	(1,155,915)	(1,488,718)
Net oil and gas properties	160,762	105,166
Unevaluated properties excluded from amortization	8,106	25,442
Total oil and gas properties	168,868	130,608
Other property and equipment, net	3,370	2,508
Restricted investments	4,044	4,065
Investment in Medusa Spar LLC	10,424	11,537
Other assets, net	1,276	1,589
Total assets	$218,326	$227,991
LIABILITIES AND STOCKHOLDERS' EQUITY (DEFICIT)		
Current liabilities:		
Accounts payable and accrued liabilities	$17,702	$12,887
Asset retirement obligations	2,822	4,002
Fair market value of derivatives	937	-
9.75% Senior Notes, net of $0 and $232 discount, respectively	-	15,820
Subtotal	21,461	32,709
Callon Entrada non-recourse credit facility (See Note 3)	-	84,847
Total current liabilities	21,461	117,556
13% Senior Notes		
Principal outstanding	137,961	137,961
Deferred credit, net of accumulated amortization of $3,964 and $294, respectively	27,543	31,213
Total 13% Senior Notes (See Note 6)	165,504	169,174
Senior secured revolving credit facility	-	10,000
Asset retirement obligations	13,103	10,648
Other long-term liabilities	2,448	1,467
Total liabilities	202,516	308,845
Stockholders' equity (deficit):		

Preferred Stock, $.01 par value, 2,500,000 shares authorized;	-	-
Common Stock, $.01 par value, 60,000,000 shares authorized; 28,984,125 and 28,742,926 shares outstanding at December 31, 2010 and December 31, 2009, respectively	290	287
Capital in excess of par value	248,160	243,898
Other comprehensive loss	(8,560)	(7,478)
Retained earnings (deficit)	(224,080)	(317,561)
Total stockholders' equity (deficit)	15,810	(80,854)
Total liabilities and stockholders' equity (deficit)	$218,326	$227,991

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

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CALLON PETROLEUM COMPANY
CONSOLIDATED STATEMENTS OF OPERATIONS
(In thousands, except per share amounts)

	For the year ended December 31, 2010	2009	2008
Operating revenues:			
Oil sales	$65,243	$73,842	$82,963
Gas sales	24,639	27,417	58,349
BOEMRE royalty recoupment	-	40,886	-
Total operating revenues	89,882	142,145	141,312
Operating expenses:			
Lease operating expenses	17,712	18,447	19,208
Depreciation, depletion and amortization	31,805	33,443	64,054
General and administrative	16,507	13,355	9,565
Accretion expense	2,446	3,149	4,172
Acquisition expense	233	298	-
Derivative expense	-	-	498
Impairment of oil and gas properties	-	-	485,498
Total operating expenses	68,703	68,692	582,995
Income (loss) from operations	21,179	73,453	(441,683)
Other (income) expenses:			
Interest expense	13,312	19,089	23,986
Callon Entrada non-recourse credit facility interest expense (See Note 3)	-	7,072	2,719
Loss on early extinguishment of debt	339	-	11,871
9.75% Senior Notes restructuring expenses	-	1,024	-
Interest on BOEMRE royalty recoupment	(91)	(7,681)	-
Other (income) expense	(166)	190	(1,379)
Total other expenses	13,394	19,694	37,197
Income (loss) before income taxes	7,785	53,759	(478,880)
Income tax benefit	(174)	-	(39,725)
Income (loss) before equity in earnings of Medusa Spar LLC	7,959	53,759	(439,155)
Equity in earnings of Medusa Spar LLC	427	660	262
Net income (loss) available to common shares	$8,386	$54,419	$(438,893)
Net income (loss) per common share:			
Basic	$0.29	$2.47	$(20.68)
Diluted	$0.28	$2.45	$(20.68)
Shares used in computing net income per common share:			
Basic	28,817	22,072	21,222

Diluted	29,476	22,200	21,222

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	Accumulated Other Comprehensive Income (Loss)	Retained Earnings (Deficit)	Total Stockholders' Equity (Deficit)
Balances at 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 plans	-	1	(1,153)	-	-	(1,152)
Tax benefits related to share-based compensation plans	-	-	2,050	-	-	2,050
Restricted stock	-	1	3,575	-	-	3,576
Warrants	-	5	(5)	-	-	-
Balances at 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 plans	-	1	205	-	-	206
Restricted stock	-	1	4,432	-	-	4,433
Common stock issued for Note exchange	-	69	11,458	-	-	11,527
Balances at December 31, 2009	$-	$287	$243,898	$ (7,478)	$(317,561)	$ (80,854)
Deconsolidation of subsidiary (See Note 3)	-	-	-	-	85,095	85,095
Comprehensive income:						
Net income	-	-	-	-	8,386	

Other comprehensive loss	-	-	-	(1,082)	-	
Total comprehensive income						7,304
Shares issued pursuant to employee benefit plans	-	1	192	-	-	193
Restricted stock	-	2	4,070	-	-	4,072
Balances at December 31, 2010	$-	$290	$248,160	$ (8,560)	$(224,080)	$ 15,810

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)

	For the year ended December 31,		
	2010	2009	2008
Cash flows from operating activities:			
Net income	$8,386	$54,419	$(438,893)
Adjustments to reconcile net income to cash provided by operating activities:			
Depreciation, depletion and amortization	32,629	34,274	64,862
Impairment of oil and gas properties	-	-	485,498
Accretion expense	2,446	3,149	4,172
Amortization of non-cash debt related items	397	2,816	4,185
Amortization of deferred credit	(3,670)	(294)	-
Equity in earnings of Medusa Spar LLC	(427)	(660)	(262)
Deferred income tax expense	1,503	18,816	(167,848)
Valuation allowance	(1,503)	(18,816)	128,123
Non-cash interest expense for Callon Entrada non-recourse credit agreement	-	3,693	-
Non-cash charge for early debt extinguishment	179	-	5,598
Non-cash charge related to compensation plans	3,107	2,335	1,550
Excess tax benefits from share-based payment arrangements	-	-	(2,050)
Payments to settle asset retirement obligations	(2,486)	(6,657)	(4,178)
Changes in current assets and liabilities:			
Accounts receivable	59,527	(45,573)	(22,215)
Other current assets	(209)	(468)	5,489
Current liabilities	907	(27,260)	22,987
Change in gas balancing receivable	347	279	630
Change in gas balancing payable	(300)	(312)	156
Change in other long-term liabilities	(115)	(12)	2,708
Change in other assets, net	(776)	(31)	(1,458)
Cash provided by operating activities	99,942	19,698	89,054
Cash flows from investing activities:			
Capital expenditures	(59,908)	(29,133)	(172,358)
Acquisitions	(995)	(15,756)	-
Proceeds from sale of mineral interests	-	-	167,349
Investment in restricted assets related to plugging and abandonment	(375)	-	-
Distribution from Medusa Spar LLC	1,540	1,700	498
Cash used in investing activities	(59,738)	(43,189)	(4,511)
Cash flows from financing activities:			
Increases in debt	-	20,337	94,435
Payments on debt	(10,000)	(10,337)	(216,000)
Redemption of remaining 9.75% senior notes	(16,052)	-	-

Equity issued related to employee stock plans	-	-	(1,152)
Excess tax benefits from share-based payment arrangements	-	-	2,050
Proceeds from exercise of employee stock options	(40)	-	-
Cash (used in) provided by financing activities	(26,092)	10,000	(120,667)
Net change in cash and cash equivalents	14,112	(13,491)	(36,124)
Cash and cash equivalents:			
Balance, beginning of period	3,635	17,126	53,250
Less: Cash held by subsidiary deconsolidated at January 1, 2010	(311)	-	-
Balance, end of period	$17,436	$3,635	$17,126

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

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Callon Petroleum Company
Notes to the Consolidated Financial Statements
(All amounts in thousands, except per-share and per-hedge data)

NOTE 1 – Description of Business and Presentation

Callon Petroleum Company has been engaged in the exploration, development, acquisition and production of oil and gas properties since 1950. The 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 unle the context requires otherwise. The Company's properties are geographically concentrated onshore in Louisiana and Texas and the offshore waters of the Gulf of Mexico.

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. and Mississippi Marketing, Inc. Fiscal years prior to 2010, CPOC also included Callon Entrada Company ("Callon Entrada"), which as discussed in Note 3 was deconsolidated from the Company's Consolidated Financial Statements effective January 1, 2010. All intercompany accounts and transactions have been eliminated. Certain prior year amounts have been reclassified to conform to presentation in the current year. To the extent these amounts are material, we have either footnoted them within the Company's disclosures or have noted the items within this footnote. The Company reclassified on its 2009 and 2008 Consolidated Statements of Cash Flow $6,657 and $4,178, respectively, between "Payments to settle asset retirement obligations" and "Capital expenditures."

NOTE 2 – Summary of Significant Accounting Policies

A. 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.

B. Cash and Cash Equivalents

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

C. 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 $339 and $65 at December 31, 2010 and 2009, respectively. During 2010, the Company recorded $274 of bad debt expense in general and administrative expenses. For 2009 and 2008, the Company recorded no provisions for bad debt to expense.

D. 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 $396 and $743 as of December 31, 2010 and 2009, respectively. Gas balancing payables were $870 and $1,171 as of December 31, 2010 and 2009, respectively.

E. 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,		
	2010	2009	2008
Shell Trading Company	44%	45%	33%
Plains Marketing, L.P.	20%	23%	23%
Louis Dreyfus Energy Services	13%	15%	16%
Other	23%	17%	28%
Total	100%	100%	100%

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.

F. Oil and Gas Properties

The Company uses the full-cost method of accounting for its exploration and development activities. Under this method of accounting, the cost of both successful and unsuccessful exploration and development activities are capitalized as property and equipment. 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 also include any internal costs that are directly related to exploration and development activities, including salaries and benefits, but do not include any costs related to production, general corporate overhead or similar activities. The Company capitalized $11,829, $10,107 and $12,623 of these internal costs during 2010, 2009 and 2008, respectively.

When applicable, proceeds from the sale or disposition of oil and gas properties are accounted for as a reduction to capitalized costs unless a significant portion (greater than 25 percent) of the Company's reserve quantities in a particular country are sold, in which case a gain or loss is recognized in income.

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. Excluded from this amortization are costs associated with unevaluated properties, including capitalized interest on such costs. 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.

Under the full cost method of accounting, the Company compares, at the end of each financial reporting period, the present value of estimated future net cash flows from proved reserves (excluding cash flows related to estimated abandonment costs), to the net capitalized costs of proved oil and gas properties net of related deferred taxes. The Company refers to this comparison as a “ceiling test.” If the net capitalized costs of proved oil and gas properties exceed the estimated discounted (at 10%) future net cash flows from proved reserves, the Company is required to write-down the value of its oil and gas properties to the value of the discounted cash flows. Historically, estimated future net cash flows from proved reserves were calculated based on period-end hedge adjusted commodity prices, and the impact of price increases subsequent to the period end could be considered. In December 2008, the Securities and Exchange Commission (“SEC”) issued a final rule, “Modernization of Oil and Gas Reporting,” which adopted revisions to the SEC’s oil and gas reporting requirements. The revisions, which became effective for the Company’s financial statements as of December 31, 2009, replaced the single-day year-end pricing with a twelve-month average pricing assumption. Additionally, consideration of the impact of subsequent price increases after period end is no longer allowed. The changes to prices used in the reserves calculation under the new rule are used in both disclosures and accounting impairment tests. In January 2010, the Financial Accounting Standards Board (“FASB”) issued its final standard on oil and gas reserve estimation and disclosures aligning its requirements with the SEC’s final rule. The new rules were considered a change in accounting principle that is inseparable from a change in accounting estimate, which did not require retroactive revision. See Note 13 for additional information regarding the Company’s oil and gas properties.

Upon the acquisition or discovery of oil and gas properties, the Company estimates by using available geological, engineering and regulatory data the future net costs to dismantle, abandon and restore the property. 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") rules, 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.

G. 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 Company adopted the new requirements effective for its year-end financial statements and our Annual Report on Form 10-K for the year ended December 31, 2009. The adoption had no material impact on the Company's financial statements.

H. Other Property and Equipment

The Company depreciates its other property and equipment using the straight-line method over estimated useful lives of three to 20 years. Depreciation expense of $446, $423 and $437 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, 2010, 2009 and 2008, respectively. The accumulated depreciation on other property and equipment was $12,047 and $11,828 as of December 31, 2010 and 2009, respectively.

I. 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 obligations and reported as accretion expense within operating expenses in the consolidated statements of operations. See Note 14 for additional information.

J. Derivatives

Settlements of oil and gas derivative contracts are 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 current and non-current portion of derivative contracts are carried at fair value in the consolidated balance sheet under the caption “Fair Market Value of Derivatives” and “Other Assets, net / Other long-term liabilities” respectively. 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. The Company’s derivative contracts are designated as cash flow hedges, and are recorded at fair market value with the changes in fair value recorded net of tax through other comprehensive income (loss) (“OCI”) in stockholders’ equity (deficit). The cash settlements on contracts for future production are recorded as an increase or decrease in oil and gas sales. Both changes in fair value and cash settlements of ineffective derivative contracts are recognized as derivative expense (income). See Notes 7 and 8 for additional information.

K. 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 12 for additional information.

L. Share-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 $2,050 of excess tax benefits classified as a financing cash inflow for the year ended December 31, 2008 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 year ended December 31, 2009, and no cash proceeds from the exercise of stock options for the years ended December 31, 2010 or 2008 due to the fact that all options were exercised through net-share settlements. See Note 10 for additional information.

M. Statements of Cash Flows

During the three year period ended December 31, 2010, the Company paid no federal income taxes. During the years ended December 31, 2010, 2009 and 2008, the company made cash interest payments of $18,579, $19,811 and $26,970, respectively.

N. Off-Balance Sheet Investment in Medusa Spar LLC

The Company holds a 10% ownership interest in Medusa Spar LLC (“LLC”), which is accounted for under the equity method of accounting for investments. The LLC owns a 75% undivided ownership interest in the deepwater spar production facilities at the Company’s Medusa Field in the Gulf of Mexico. The LLC earns a tariff based upon production volume throughput from the Medusa area. Callon is obligated to process through the spar production facilities its share of production from the Medusa Field and any future discoveries in the area. The balance of Medusa Spar LLC is owned by Oceaneering International, Inc. and Murphy Oil Corporation.

O. Consolidation of Variable Interest Entities (“VIE”)

In June 2009, the Financial Accounting Standards Board (“FASB”) issued an accounting standard which became effective for the Company on January 1, 20101, and which amended US GAAP as follows:

- 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;
- to require ongoing reassessment of whether an enterprise is the primary beneficiary of a VIE, rather than only when specific events occur;
- to eliminate the quantitative approach previously required for determining the primary beneficiary of a VIE;
- to amend certain guidance for determining whether an entity is a VIE;
- to add an additional reconsideration event when changes in facts and circumstances pertinent to a VIE occur;
- to eliminate the exception for troubled debt restructuring regarding VIE reconsideration; and
- to require advanced disclosures that will provide users of financial statements with more transparent information about an enterprise’s involvement in a VIE.

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. Therefore, effective January 1, 2010, Callon Entrada was deconsolidated from the consolidated financial statements of the Company. For additional information, see Note 3 "Deconsolidation of Callon Entrada."

P. Earnings per Share ("EPS")

The Company's basic EPS amounts have been computed based on the weighted-average number of shares of common stock outstanding for the period. Diluted EPS reflects the potential dilution, using the treasury-stock method, which assumes that options were exercised and restricted stock was fully vested. Diluted EPS also includes the impact of unvested share appreciation plans. For awards in which the share price goals have already been achieved, shares are included in diluted EPS using the treasury-stock method. For those awards in which the share price goals have not been achieved, the number of contingently issuable shares included in the diluted EPS is based on the number of shares, if any, using the treasury-stock method, that would be issuable if the market price of the Company's stock at the end of the reporting period exceeded the share price goals under the terms of the plan.

Q. Treasury Stock

The Company applies the weighted-average-cost method of accounting for treasury stock transactions and held 29 treasury shares as of December 31, 2010.

R. Recent Accounting Pronouncements

In January 2010, the Financial Accounting Standards Board issued guidance which added new requirements for fair value disclosures about transfers into and out of Levels 1 and 2 and separate disclosures about purchases, sales, issuances and settlements relating to Level 3 measurements. The guidance also clarified existing requirements regarding the level of disaggregation as well as inputs and valuation techniques used to measure fair value. The guidance is effective for the first reporting period beginning after December 31, 2009, except for the requirement to provide the Level 3 activity of purchases, sales, issuances, and settlements on a gross basis, which are effective for fiscal years beginning after December 31, 2010. The adoption of this guidance had no material impact on the Company's fair value disclosures. See Note 8 for additional information.

NOTE 3 - Deconsolidation of Callon Entrada

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 $155,000, and reimbursed the Company $12,600 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 Callon Entrada, a wholly owned subsidiary of the Company, up to $150,000 plus interest expense incurred up to $12,000, for its share of the development costs for the Entrada project. Based on the terms of the credit agreement with CIECO Energy (Entrada) LLC ("CIECO Entrada"), the debt was to be repaid solely from assets, primarily production, from the Entrada field. All assets of Callon Entrada, and its stock, are pledged to CIECO Entrada under the Callon Entrada credit agreement, and neither Callon nor its subsidiaries (other than Callon Entrada) guaranteed the Callon Entrada credit facility.

Prior to January 1, 2010 and prior to the issuance of revised accounting rules regarding the consolidating of VIEs, the Company was required to consolidate the financial statements and results of operations of Callon Entrada, and as such, Callon Entrada's non-recourse principal and interest due under the credit facility was reflected in a separate line item in Callon's 2009 consolidated financial statements.

Based on the Company's re-evaluation under the revised accounting rules, which are detailed in Note 2, the Company 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, as a result, Callon Entrada was deconsolidated from the Company's consolidated financial statements as of January 1, 2010. Key events considered in this analysis include the following:

Default on non-recourse debt and CIECO's acceleration rights exercised: As a result of abandoning the Entrada project in November 2008, prior to completion, Callon Entrada's only source of payment is the proceeds from the sale of equipment purchased but not used for the Entrada project. 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, and to invoke its rights to the surplus equipment related to the Entrada project, including the proceeds from the sale of the equipment and the ability to control the decisions related to the sale of the equipment. Based on the advice of legal counsel, Callon believes that it and its other subsidiaries are not otherwise obligated to repay the principal, accrued interest or any other amounts which may become due under the Callon Entrada credit facility. 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 above. While as of January 1, 2010 Callon Entrada had been deconsolidated from these financial statements such that no principal or interest were recorded as outstanding on the Consolidated Balance Sheet at December 31,2010 under this facility, at December 31, 2009, $78,435 of principal and $6,412 of interest were outstanding under this facility.

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Abandonment obligations satisfied: Callon guaranteed Callon Entrada's payment of all amounts to plug and abandon the 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 Bureau of Ocean Energy Management, Regulation and Enforcement ("BOEMRE," formerly the Minerals Management Service) confirmed to Callon during September 2009 that Callon had satisfied all if its abandonment obligations related to this project.

No ability to control future actions of Callon Entrada: As of December 31, 2009, the wind down of the Entrada project was complete, all of the costs related to the Entrada project were paid, and subsequent to the lease expiration June 1, 2009, control of the property reverted to the BOEMRE. The sale of remaining equipment purchased for the Entrada project remains ongoing. The Company believes that the amount of future operating costs of Callon Entrada, for which the Company would be responsible for, is insignificant and is limited to minimal storage fees for the surplus equipment while the equipment is being liquidated. As of December 2010, Callon Entrada has collected $4,235 in sales proceeds from the sale of equipment, net to its interest, which has been applied to unpaid interest expense as required under the Callon Entrada credit facility.

As a result of the events described above, the Company lost its power to direct the only remaining activities that affect Callon Entrada's future economic performance. Below is a condensed balance sheet of Callon presented to demonstrate the effect of deconsolidation on the financial statements at January 1, 2010:

	Callon Consolidated at 12/31/09	Callon Entrada Deconsolidated	Callon Consolidated at 1/1/2010
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 non-recourse credit facility	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

See Note 19 for subsequent information regarding Callon Entrada.

NOTE 4 - Earnings 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 (in thousands, except per share amounts):

	For the year ended December 31,		
	2010	2009	2008
(a) Net income	$8,386	$54,419	$(438,893)
(b) Weighted average shares outstanding (1)	28,817	22,072	21,222
Dilutive impact of stock options	108	-	-
Dilutive impact of restricted stock	551	128	-
(c) Weighted average shares outstanding for diluted net income per share (1)	29,476	22,200	21,222
Basic net income per share (a¸b)	$0.29	$2.47	$(20.68)
Diluted net income per share (a¸c)	$0.28	$2.45	$(20.68)

(1) During February 2011, the Company completed an equity offering of an addition 10,100 share of common stock, which have been excluded from the above shares outstanding as of December 31, 2010. See Note 19.

The following were excluded from the diluted EPS calculation because their effect would be anti-dilutive:

Stock options	122	978	161

Because the Company reported a loss for the year ended December 31, 2008, the following were excluded from the dilution calculation: 161, 328 and 129 for stock options, warrants and restricted stock, respectively.

NOTE 5 – Other Comprehensive Income (Loss)

A summary of the Company's comprehensive income (loss) is detailed below (in thousands, net of tax):

	For the year ended December 31,		
	2010	2009	2008
Net income	$ 8,386	$ 54,419	$ (438,893)
Other comprehensive income (loss):			
Change in fair value of derivatives	(1,082)	(21,635)	17,540
Total comprehensive income (loss)	$ 7,304	$ 32,784	$ (421,353)

NOTE 6 - Borrowings

The Company's borrowings consisted of the following at:

	December 31, 2010		December 31, 2009	
Principal components:				
Credit Facility	$	-	$	10,000
9.75% Senior Notes due 2010, principal		-		16,052
13% Senior Notes due 2016, principal		137,961		137,961
Callon Entrada Credit Facility; non-recourse (1)		-		84,847
Total principal outstanding		137,961		248,860
Non-cash components:				
9.75% Senior Notes, due 2010 Unamortized discount		-		(232)
13% Senior Notes due 2016 Unamortized deferred credit		27,543		31,213
Total carrying value of borrowings	$	165,504	$	279,841

(1) Liability was eliminated as part of the deconsolidation of Callon Entrada. See Note 3 for additional information.

Senior Secured Revolving Credit Facility (the “Credit Facility”)

In January 2010, the Company amended its Credit Facility agreement to include Regions Bank as the sole arranger and administrative agent. The third amended and restated Credit Facility, which matures on September 25, 2012, provides for a $100,000 facility and had an initial borrowing base of $20,000, which is reviewed and re-determined on a semi-annual basis during the second and fourth quarters. The Credit Facility bears interest at 4% above a defined base rate, and in no event will the interest rate be less than 6%. As of December 31, 2010, the interest rate on the facility was 6%. In addition, a commitment fee of 0.5% per annum on the unused portion of the borrowing base, is payable quarterly. During October 2010, Regions Bank approved a $30,000 borrowing base, which represents a $10,000 or 50% increase over the Company’s previous $20,000 borrowing base with Regions Bank, and is secured by mortgages covering the Company’s major oil fields. The next borrowing base review is scheduled for the second quarter of 2011.

Simultaneously with the January 2010 execution of the third amended and restated Credit Facility, the Company repaid the $10,000 outstanding draw under the second amended and restated Credit Facility, which was outstanding as of December 31, 2009. No balance on this facility was outstanding at December 31, 2010.

9.75% Senior Notes (“Old Notes”) (Due December 2010)

During the fourth quarter of 2009, Callon commenced an exchange offer for any and all of its outstanding Old Notes. Holders of approximately 92% of the Old Notes tendered their Notes in the exchange offer.   During March 2010, the Company announced its intention to redeem all remaining Old Notes by April 30, 2010 (the “Redemption Date”) at a redemption price of 101% of their principal amount, plus accrued and unpaid interest to the Redemption Date.

On April 30, 2010, the Company completed its publically announced plans to redeem for 101% of the face value the remaining $16,052 outstanding Old Notes for $16,343, which included the 1% call premium and $130 of accrued interest through the repurchase date. The Company also recognized $179 of additional interest expense related to the accelerated amortization of the Old Notes' remaining discount and debt issuance costs, which when added to the $160 call premium resulted in a $339 loss on early extinguishment of this debt. Since the April 30, 2010 redemption date, no Old Notes remain outstanding.

13% Senior Notes due 2016 ("Senior Notes") and Deferred Credit

As described above, during the fourth quarter of 2009, the Company exchanged approximately 92% of the principal amount, or $183,948, of the Old Notes for $137,961 of Senior Notes. The exchange resulted in a 25% reduction in the principal amount of the Old Notes tendered, and included a 3.25% increase in the coupon rate from 9.75% to 13%. In addition, holders of the tendered notes received 3,794 shares of common stock and 311 shares of Convertible Preferred Stock which was valued on November 24, 2009 in the amount of $11,527 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 Senior Notes' 13% interest coupon is payable on the last day of each quarter.

Upon issuing the Senior Notes during November 2009, the Company reduced the carrying amount of the Old Notes by the fair value of the common and preferred stock issued in the amount of $11,527. The $31,507 difference between the adjusted carrying amount of the Old Notes and the face value of the Senior Notes was recorded as a deferred credit, which is being amortized as a reduction in interest expense over the life of the Senior Notes at an 8.5% effective interest rate. The following table summarizes the Company's deferred credit balance at December 31, 2010:

Gross Carrying Amount	Accumulated Amortization at December 31, 2010	Carrying Value at December 31, 2010	Amortization Recorded during 2010 as a Reduction of Interest Expense	Estimated Amortization Expected to be Recorded during 2011(1)
$31,507	$ 3,964	$27,543	$ 3,670	$ 9,162

(1) As discussed below, the Company initiated the redemption of $31,000 face value of its 13% Senior Notes, which is expected to be completed on March 19, 2011. As a result of the early redemption of this debt, the Company will recognize accelerated amortization of $6,004 for a proportionate share of the deferred credit, thereby increasing the full-year expected amortization to the amount reflected in the table. Deferred credit amortization expected to be recorded as a reduction in interest expense during 2012, 2013, 2014, 2015 and thereafter is $3,350, $3,647, $3,971, $4,323 and $3,098, respectively.

Following the completion of an equity offering during February, 2011, the Company provided the formal notice to holders of its Senior Notes, as required by the terms of the Senior Notes, to call $31,000 of face value of the Notes. See Note 19 for additional information.

Certain of the Company's subsidiaries guarantee the Company's obligations under the Senior 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 Senior Notes and the Company's Credit Facility contains various covenants including restrictions on additional indebtedness and payment of cash dividends. In addition, Callon's Credit Facility contains covenants for maintenance of certain financial ratios. The Company was in compliance with these covenants at December 31, 2010.

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NOTE 7 – Derivative Instruments and Hedging Activities

Objectives and Strategies for Using Derivative Instruments

The Company is exposed to fluctuations in crude oil and natural gas prices on the majority of its production. Consequently, the Company believes it is prudent to manage the variability in cash flows on a portion of its crude oil and natural gas production. The Company utilizes primarily collars and swap derivative financial instruments to manage fluctuations in cash flows resulting from changes in commodity prices. The Company does not use these instruments for trading purposes.

Counterparty Risk

The use of derivative transactions exposes the Company to counterparty credit risk, or the risk that a counterparty will be unable to meet its commitments. To reduce the Company's risk in this area, counterparties to the Company's commodity derivative instruments predominantly include a large, well-known financial institution and a large, well-known oil and gas company. The Company monitors counterparty creditworthiness on an ongoing basis; however, it cannot predict sudden changes in counterparties' creditworthiness. In addition, even if such changes are not sudden, the Company may be limited in its ability to mitigate an increase in counterparty credit risk. Should one of these counterparties not perform, the Company may not realize the benefit of some of its derivative instruments under lower commodity prices.

The Company executes commodity derivative transactions under master agreements that have netting provisions that provide for offsetting payables against receivables. In general, if a party to a derivative transaction incurs an event of default, as defined in the applicable agreement, the other party will have the right to demand the posting of collateral, demand a transfer or terminate the arrangement.

Settlements and Financial Statement Presentation

Settlements of oil and gas derivative contracts are 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 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. For additional information, including the balance sheet presentation of derivative instrument asset and liability balances, See Note 8 for additional information.

The Company's derivative contracts are designated as cash flow hedges, and are recorded at fair market value with the changes in fair value recorded net of tax through other comprehensive income (loss) ("OCI") in stockholders' equity (deficit). The cash settlements on contracts for future production are recorded as an increase or decrease in oil and gas sales. Both changes in fair value and cash settlements of ineffective derivative contracts are recognized as derivative expense (income).

Listed in the table below are the outstanding oil and gas derivative contracts, consisting entirely of collars, as of December 31, 2010:

Product	Volumes per Month	Quantity Type	Average Floor Price per Hedge	Average Ceiling Price per Hedge	Period
Oil	10	Bbls	$75.00	$101.85	Jan11 - Dec11
Oil	5	Bbls	$80.00	$102.00	Jan11 - Dec11

Oil	10	Bbls	$75.00	$94.50	Jan11 - Dec11

The tables below present the effect of the Company's derivative financial instruments on the consolidated statements of operations as an increase (decrease) to oil and gas sales:

	For the year ended December 31,		
	2010	2009	2008
Amount of Gain (Loss) Reclassified from OCI into Income (1)	$632	$19,242	$(9,909)
Amount of Gain Recognized in Income (2)	-	-	498

(1) Effective portion
(2) Ineffective Portion and amount Excluded from Effectiveness Testing

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NOTE 8 – Fair Value Measurements

Fair value is defined within the accounting rules as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. The rules established a fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value. As presented in the tables below, this hierarchy consists of three broad levels:

Level 1 Valuations consist of unadjusted quoted prices in active markets for identical assets and liabilities and has the highest priority;

Level 2 Valuations rely on quoted prices in markets that are not active or observable inputs over the full term of the asset or liability;

Level 3 Valuations are based on prices or third party or internal valuation models that require inputs that are significant to the fair value measurement and are less observable and thus have the lowest priority.

Fair Value of Financial Instruments

Cash, Cash Equivalents, and Short-Term Investments. The carrying amounts for these instruments approximate fair value due to the short-term nature or maturity of the instruments.

Debt. The Company's debt is recorded at the carrying amount on its Consolidated Balance Sheet. The fair value of Callon's fixed-rate debt is based upon estimates provided by an independent investment banking firm. The carrying amount of floating-rate debt approximates fair value because the interest rates are variable and reflective of market rates.

The following table summarizes the respective carrying and fair values at:

	December 31,			
	2010		2009	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Credit Facility	$-	$-	$10,000	$10,000
9.75% Senior Notes due 2010, net of unamortized discount	-	-	15,820	15,249
13% Senior Notes due 2016 (a)	165,504	140,030	169,174	103,471
Callon Entrada Credit Facility; non-recourse	-	-	84,847	-
Total	$165,504	$140,030	$279,841	$128,720

(a) 2010 Fair value is calculated only in relation to the $137,961 face value outstanding of the 13% Senior Notes. The remaining $27,543, which the Company has recorded as a deferred credit, is excluded from the fair value calculation, and will be recognized in earnings as a reduction of interest expense over the remaining amortization period. See Note 6 for additional information.

Assets and Liabilities Measured at Fair Value on a Recurring Basis

Certain assets and liabilities are reported at fair value on a recurring basis (unless otherwise noted below) in Callon's Consolidated Balance Sheet. The following methods and assumptions were used to estimate the fair values:

Commodity Derivative Instruments. Callon's derivative policy allows for commodity derivative instruments to consist of collars and natural gas and crude oil basis swaps, though at December 31, 2010 the Company's portfolio included only collars. The fair value of these derivatives is derived using a valuation model that utilizes market-corroborated inputs that are observable over the term of the derivative contract, and the values are corroborated by quotes obtained from counterparties to the agreements. The Company's fair value calculations also incorporate an estimate of the counterparties' default risk for derivative assets and an estimate of the Company's default risk for derivative liabilities. Prior to the fourth quarter of 2010, the Company considered many of the inputs to fall with Level 3 of the accounting guidance. During its year-end review of the valuation calculation, the Company determined that the inputs now primarily fall within Level 2 of the fair-value hierarchy based on the wide availability of quoted market prices for similar commodity derivative contracts. This transfer from a Level 3 classification to a Level 2 classification is reflected in the reconciliation performed below. See Note 7 for additional information regarding the Company's derivative instruments.

The following tables present the Company's assets and liabilities measured at fair value on a recurring basis for each hierarchy level:

As of December 31, 2010	Balance Sheet Presentation	Level 1	Level 2	Level 3	Total
Assets					
Derivative financial instruments - current Portion	Fair market value of derivatives	$-	$-	$-	$-
Derivative financial instruments - non-current	Other assets, net	-	-	-	-
Liabilities					
Derivative financial instruments - current Portion	Fair market value of derivatives	$-	$937	$-	$937
Derivative financial instruments - non-current	Other long-term liabilities	-	-	-	-
Total		$-	$(937)	$-	$(937)

The derivative fair values above are based on analysis of each contract. Derivative assets and liabilities with the same counterparty are presented here on a gross basis, even where the legal right of offset exists. See Note 7 for a discussion of net amounts recorded in the Consolidated Balance Sheet at December 31, 2010.

The following table presents the Company's Level 3 assets and liabilities measured at fair value on a recurring basis using significant, unobservable inputs:

	Derivatives
Balance at January 1, 2010	$145
Total gains or losses (realized or unrealized):	
Included in earnings	632
Included in other comprehensive (income) loss	(1,082)
Purchases, issuances and settlements	(632)
Transfers (in) and out of Level 3 (a)	937
Balance at December 31, 2010	$-
Change in unrealized gains (losses) included in earnings relating to derivatives still held as of December 31, 2010	$-

(a) As discussed above, during its year-end review of its commodity derivatives instrument valuation calculation, the Company determined that the inputs now primarily fall within Level 2 of the fair-value hierarchy based on the wide availability of quoted market prices for similar commodity derivative contracts.

Assets and Liabilities Measured at Fair Value on a Nonrecurring Basis

Certain assets and liabilities are reported at fair value on a nonrecurring basis in Callon's Consolidated Balance Sheet. The following methods and assumptions were used to estimate the fair values:

Asset Retirement Obligations Incurred in Current Period. Callon estimates the fair value of AROs based on discounted cash flow projections using numerous estimates, assumptions and judgments regarding such factors as (1) the existence of a legal obligation for an ARO, (2) amounts and timing of settlements, (3) the credit-adjusted risk-free rate to be used and (4) inflation rates. AROs incurred for the year ended December 31, 2010 and resulting in fair value measurement, including upward revisions to ARO liabilities of $1,608, were Level 3 fair value measurements. See Note 14 for a summary of changes in the Company's ARO liability.

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NOTE 9 – 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. 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 $690, $640 and $747 in the years 2010, 2009 and 2008, respectively.

1996 Stock Incentive Plan (the "1996 Plan")

The 1996 Plan, first adopted by the Board of Directors on August 23, 1996 and approved by the shareholders during 1997 and as amended, authorized and reserved for issuance 2,200 shares of common stock for issuance upon exercise of vested stock options and vesting of other share-based equity awards. Unvested options under this plan are subject to various accelerated vesting and forfeiture provisions subject to the occurrence of certain events, and unexercised, vested options expire 10 years from the date of grant. Equity awards under the plan generally vest over time or subject to attaining a specified metric, but vesting of awards may be immediate or cliff vest at a specified date. The Company recognizes expense on the grant date for all immediately vesting awards, while it recognizes expense ratably over the requisite service (i.e. vesting) period for both cliff and ratably vesting awards. For performance-based awards, the Company recognizes expense based on its analysis of the performance criteria, and records or reverses expense as necessary based on its analysis.

During 2010, the Company awarded 120 restricted stock units to non-employee members of the Board of Directors of the Company, which cliff vest on May 7, 2011. Other activity within the 1996 Plan during 2010 included the expiration of 278 vested, unexercised stock options, the forfeiture of 4.3 restricted stock units due to an employee departure from the Company, and the vesting of 152.5 restricted stock units awarded in prior years. As of December 31, 2010, the 1996 Plan had 329.5 shares remaining and eligible for future issuance.

2002 Stock Incentive Plan (the "2002 Plan")

The 2002 Plan, adopted by the Board of Directors on February 14, 2002, authorized and reserved for issuance 350 shares of common stock for issuance upon exercise of vested stock options and vesting of other share-based equity awards. The 2002 Plan is considered a "broadly-based plan" and did not require shareholder approval. Unvested options under this plan are subject to various accelerated vesting and forfeiture provisions subject to the occurrence of certain events, and unexercised, vested options expire 10 years from the date of grant. Equity awards under the plan generally vest over time or subject to attaining a specified metric, but vesting of awards may be immediate or cliff vest at a specified date. The Company recognizes expense on the grant date for all immediately vesting awards, while it recognizes expense ratably over the requisite service (i.e. vesting) period for both cliff and ratably vesting awards. For performance-based awards, the Company recognizes expense based on its analysis of the performance criteria, and records or reverses expense as necessary based on its analysis.

During 2010, the Company awarded 10 restricted stock units which vest one-third on each anniversary date following the award date. Other activity within the 2002 Plan during 2010 included the exercise of 1.3 stock options and the vesting of 3.5 restricted stock units awarded in prior years. As of December 31, 2010, the 2002 Plan had 27.5 shares remaining and available for future issuance.

2006 Stock Incentive Plan (the "2006 Plan")

The 2006 Plan, adopted by the Board of Directors on March 9, 2006 and approved by the shareholders at the May 4, 2006 annual meeting, authorized and reserved for issuance 500 shares of common stock for issuance upon exercise of vested stock options and vesting of other share-based equity awards. Unvested options under this plan are subject to various accelerated vesting and forfeiture provisions subject to the occurrence of certain events, and unexercised, vested options expire 10 years from the date of grant. Equity awards under the plan generally vest over time or subject to attaining a specified metric, but vesting of awards may be immediate or cliff vest at a specified date. The Company recognizes expense on the grant date for all immediately vesting awards, while it recognizes expense ratably over the requisite service (i.e. vesting) period for both cliff and ratably vesting awards. For performance-based awards, the Company recognizes expense based on its analysis of the performance criteria, and records or reverses expense as necessary based on its analysis.

During 2010, the Company did not grant any new awards under this plan. Other activity during 2010 included the forfeiture of 64 restricted stock units for failure to reach the minimum performance metric, forfeiture of 5.5 restricted stock units due to an employee departure from the Company and the vesting 21.3 restricted stock units awarded in prior years. As of December 31, 2010, the 2006 Plan had 110.5 shares remaining and available for future issuance.

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2009 Stock Incentive Plan (the "2009 Plan")

The 2009 Plan, adopted by the Board of Directors on March 5, 2009 and approved by shareholders on April 30, 2009, authorizes and reserves for issuance 1,250 shares of common stock for issuance upon exercise of vested stock options and vesting of other share-based equity awards. Unvested options under this plan are subject to various accelerated vesting and forfeiture provisions subject to the occurrence of certain events, and unexercised, vested options expire 10 years from the date of grant. Equity awards under the plan generally vest over time or subject to attaining a specified metric, but vesting of awards may be immediate or cliff vest at a specified date. The Company recognizes expense on the grant date for all immediately vesting awards, while it recognizes expense ratably over the requisite service (i.e. vesting) period for both cliff and ratably vesting awards. For performance-based awards, the Company recognizes expense based on its analysis of the performance criteria, and records or reverses expense as necessary based on its analysis.

During 2010, the Company awarded 49.5 restricted stock units which vest one-third on each anniversary date following the award date and 805.5 restricted stock units which cliff vest on May 7, 2013. Other activity during 2010 included the forfeiture of 90 restricted stock units due to an employee departure from the Company. As of December 31, 2010, the 2009 Plan had 313.2 shares remaining and available for future issuance.

Stock Incentive Award for Inducement of Employment

On June 1, 2009, under an exception available by the New York Stock Exchange as an inducement of employment, the Company awarded to its new Executive Vice President and Chief Operating Officer ("COO") 200 restricted stock units of which one-half were to vest on June 1, 2012 based on achieving certain metrics and one-half was to vest on June 1, 2013 subject to the COO being employed by the Company on that date. The vesting of the portion of the award subject to achieving a specified metric was contingent upon the Company's relative ranking amongst a Company-selected peer group of other public oil and gas companies, and was subject to a 0% - 150% adjustment. The Company also awarded the COO 500 stock options with vesting determined by the Company's stock price achieving certain levels. These stock options were approved to cliff vest in one-third increments upon the stock price reaching specified levels. Following the COO's resignation from Callon during September 2010 to join another oil and gas company as its Chief Executive Officer, the COO forfeited all of his restricted and performance-based shares and 333 of the unvested performance-based stock options. Prior to his departure, the Company achieved the first of three performance metrics specified in the performance-based stock options agreement resulting in the vesting of these 167 options, for which the Company recorded approximately $180 of compensation expense.

On April 1, 2010, under an exception available by the New York Stock Exchange as an inducement of employment, the Company awarded 50 shares of restricted stock to its new Senior Vice President of Operations. The restricted stock was approved to cliff vest on January 1, 2011, and had been fully expensed at December 31, 2010.

Other Incentive Awards

During 2009, the Company awarded 121.5 restricted stock units that cliff vest in August, 2012 and allow for automatic early vesting upon a qualifying retirement. Vesting units under this award will be settled in cash based on the closing price of the Company's common stock on the date of vesting. This award is accounted for as a liability award, and is recorded on the Company's consolidated balance sheet at its fair value, with changes in fair value of the award recorded as adjustment to compensation expense.

During 2010, the Company awarded 94.5 restricted stock units that cliff vest in May, 2012. Subsequent to the issuance, 15 of these restricted stock units were forfeited following an employee departure from the Company. Upon vesting, these units will be paid in cash based on the closing stock price of the Company's common stock on the vesting date. This award is accounted for as a liability award, and is recorded on the Company's consolidated balance sheet for the ratable portion of its fair value, with changes in fair value of the award recorded as adjustment to compensation expense.

During 2010, the Company awarded 400 restricted stock units that cliff vest in December, 2012, which will ultimately be settled in cash. Subsequent to the issuance, 50 of these performance-based restricted stock units were forfeited following an employee departure from the Company. The number of units that will ultimately vest will be based on a calculation that compares the Company's total shareholder return the same calculated return of a group of peer companies as selected by the Company, and the number of units that vest can range between 0% and 150% of the remaining 350 restricted stock units. Because this award is payable in cash, the entire award is accounting for as a liability, and is recorded on the Company's consolidated balance sheet for the ratable portion of its fair value, which changes in fair value of the award recorded as adjustments to compensation expense.

Tabular disclosures related to the share-based awards are presented below in Note 10.

NOTE 10 - Share-Based Compensation

As discussed in Note 9, "Employee Benefit Plans," 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 share-based compensation. Shares available for future stock option or restricted stock grants to employees and directors under existing plans were 781 at December 31, 2010. The Company recorded non-cash share-based compensation expense of $5,701, $4,821 and $4,699 during the years ended December 31, 2010, 2009 and 2008, respectively. The portion of this non-cash share-based compensation expense that was included in general and administrative expense totaled $3,107, $2,335 and $2,633 for the same years respectively, and the portion capitalized to oil and gas properties was $2,594, $2,486 and $2,066, respectively. Non-cash share-based compensation included:

	For the year ended December 31,		
	2010	2009	2008
Non-cash compensation expense for options	$206	$144	$93
Non-cash compensation expense for restricted stock	3,898	4,302	4,389
Non-cash compensation expense for share-based units	1,396	182	-
Non-cash compensation expense for 401(k) contributions in shares	201	193	217
Total non-cash compensation expense	$5,701	$4,821	$4,699

The following table presents unrecognized compensation expense expected to be recognized in future periods:

	As of December 31,		
	2010	2009	2008
Unrecognized compensation costs related to unvested options	$ 57	$ 649	$ 179
Unrecognized compensation costs related to equity-based unvested restricted stock units	3,353	3,201	6,869
Unrecognized compensation costs related to liability-based unvested restricted stock units	2,676	-	-

	2011	2012	2013	2014	Thereafter	Total
Future share-based compensation expense expected to be recognized for options	$ 57	$ -	$ -	$ -	$ -	$ 57
Future share-based compensation expense expected to be recognized for equity-based unvested restricted stock units	1,751	1,193	409	-	-	3,353
Future share-based compensation expense expected to be recognized for liability-based unvested restricted stock units	1,311	1,311	54	-	-	2,676

Liability-based restricted stock unit awards accounted are recorded on the Company's consolidated balance sheet at December 31, 2010, 2009 and 2008 for $1,578, $182 and $0, respectively. This liability is marked to fair value each reporting period with changes in the fair value recognized in compensation expense.

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 either 2010 or 2008.

	For the year ended December 31, 2010	2009	2008
Dividend yield	n/a	0.0 %	n/a
Expected volatility	n/a	136.0 %	n/a
Risk-free interest rate	n/a	3.9 %	n/a
Expected life of option (in years)	n/a	9	n/a
Weighted-average grant-date fair value	n/a	$1.23	n/a
Forfeiture rate	n/a	0.0 %	n/a

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 year-ended December 31, 2010		2009		2008	
	Shares	Wtd Avg Ex Price per Option	Shares	Wtd Avg Ex Price per Option	Shares	Wtd Avg Ex Price per Option
Outstanding, beginning of year	978	$6.37	513	$10.27	755	$10.00
Granted (at market)	-	-	500	2.76	-	-
Exercised	(168)	2.77	-	-	(239)	9.34
Forfeited	(335)	2.78	(15)	14.44	(3)	15.97
Expired	(278)	10.61	(20)	9.99	-	-
Outstanding, end of year	198	$9.57	978	$6.37	513	$10.27
Exercisable, end of year	184	$8.99	465	$9.93	488	$9.91
Weighted-average remaining contract life per unit:						
Outstanding options at end of period in years	3.06		5.75		2.92	
Outstanding exercisable at end of period in years	2.86		1.78		2.68	

	As of December 31, 2010	2009	2008
Aggregate intrinsic value of options outstanding & exercisable	$ -	$ -	$ -
Aggregate intrinsic value of options exercised during the year	175	-	4,100
Fair value of shares vesting during the year	207	58	145

Restricted Stock Units

The following table represents unvested restricted stock activity for the year ended December 31, 2010:

	Number of Shares	Weighted average Grant-Date Fair Value per Share	Period over which expense is expected to be recognized
Outstanding at the beginning of the period	927	$7.01	
Granted	1,430	5.21	
Vested	(177)	8.62	
Forfeited	(409)	6.75	
Outstanding at the end of the period	1,771	$5.46	1.9 years

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NOTE 11 – Equity Transactions

During the fourth quarter of 2009, the Company commenced an exchange offer for any and all of its outstanding 9.75% 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 tendered their notes in the exchange offer, and 6,902 shares of common stock were issued to the tendering notes holders after the Convertible Preferred Stock was converted into common shares.

During February 2011, the Company received $73,720 in net proceeds through the public offering of 10,100 shares of its common stock, which included the issuance of 1,100 shares pursuant to the underwriters' over-allotment option. See Note 19 for additional information.

NOTE 12 – Income Taxes

The following table presents Callon's net unrecognized tax benefits relating to its reported net losses and other temporary differences from operations:

	For the year ended December 31	
	2010	2009
Deferred tax asset:		
Federal net operating loss carryforward	$79,680	$94,125
Statutory depletion carryforward	6,140	4,895
Alternative minimum tax credit carryforward	208	383
Asset retirement obligations	4,018	3,704
Other	16,807	34,170
Deferred tax asset before valuation allowance	106,853	137,277
Less: Valuation allowance	(85,222)	(116,676)
Total deferred tax asset	21,631	20,601
Deferred tax liability:		
Oil and gas properties	21,631	9,555
Other	-	11,046
Total deferred tax liability	21,631	20,601
Net deferred tax asset	$-	$-

As of January 1, 2010 and as previously disclosed in Note 3, Callon Entrada has been deconsolidated from the Company's consolidated financial statements, resulting in a $30,330 decrease in deferred tax assets and a corresponding reduction in the valuation allowance.

For the years ended December 31, 2010 and 2009, the Company recorded a full valuation allowance against its net deferred tax assets. Consequently, the Company's effective tax rate will be affected in future periods to the extent these deferred tax assets are recognized. The Company continues to assess whether or not deferred tax assets can be recognized based on current and expected future operating results and other factors.

If not utilized, the Company's federal net operating loss carryforwards of $227,657 will expire in 2012 through 2030, of which $20,919 is scheduled to expire over the next five-years including $1,422 and $19,497 in 2012 and 2014, respectively. To the extent the Company experiences a Section 382 Ownership Change as a result of the equity offering completed in February 2011 (discussed in Note 19) or any other potential triggering event, the Company's ability to utilize these potential NOL carrybacks and realize this potential refund, as well as certain of its other tax attributes, may be limited.

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The Company's state net operating loss carryforwards in the amount of $171,380 as of December 31, 2010 will expire in 2011 through 2030 of which $55,748 is scheduled to expire over the next five-years including $1,415, $1,599, $23,792, $16,327 and $12,615 from 2011 through 2015, respectively. 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 December 31, 2010. 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 1999 through 2009 remain open to examination by the federal and state taxing jurisdictions to which the Company is subject.

In addition, the net operating loss ("NOL") carryback provision of the Internal Revenue Code was amended on November 6, 2009, as part of The Worker, Homeownership and Business Assistance Act of 2009 (the "WHB Act"). The WHB Act allows businesses with net operating losses ("NOLs") for 2008 and 2009 to carry back losses for up to five years and suspends the 90% limitation on the use of any alternative minimum tax NOL deduction attributable to carrybacks of the applicable NOL. There would be no limit on the NOL carrybacks for the first four preceding years of the carryback period, but for the fifth preceding year, the NOL carryback would be limited to fifty percent of a company's taxable income in that year. In applying the new five-year NOL carryback rule, the Company was able to file for a refund claim to recover approximately $174.

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.

	For the years ended December 31,		
Component of Income Tax Rate Reconciliation	2010	2009	2008
Income tax expense computed at the statutory federal income tax rate	35 %	35 %	(35)%
Change in valuation allowance	(21)%	(34)%	27 %
Percentage depletion carryforward	(15)%	0 %	0 %
Other	3 %	(1)%	0 %
Effective income tax rate	2 %	0 %	(8)%

	For the years ended December 31,		
Components of Income Tax Expense	2010	2009	2008
Current income tax expense (benefit)	$(174)	$-	$-
Deferred income tax (benefit) expense	1,503	18,816	(167,848)
Valuation allowance	(1,503)	(18,816)	128,123
Total income tax (benefit) expenses	$(174)	$-	$(39,725)

During 2010, the Company reduced the valuation allowance by the amount of estimated taxable income generated for the year.

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NOTE 13 – 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.

	For the year ended December 31,		
	2010	2009	2008
Capitalized costs incurred:			
Evaluated Properties-			
Beginning of period balance	$1,593,884	$1,581,698	$1,349,904
Deconsolidation of Subsidiary January 1, 2010	(364,589)	-	-
Property acquisition costs	10,676	23,748	6,126
Exploration costs	14,739	-	2,578
Development costs	61,967	(11,562)	223,090
End of period balance	$1,316,677	$1,593,884	$1,581,698
Unevaluated Properties (excluded from amortization):			
Beginning of period balance	$25,442	$32,829	$70,176
Additions	3,561	6,140	6,409
Capitalized interest	2,000	3,213	6,496
Transfers to evaluated	(22,897)	(16,740)	(50,252)
End of period balance	$8,106	$25,442	$32,829
Accumulated depreciation, depletion and amortization:			
Beginning of period balance	$1,488,718	$1,455,275	$738,374
Provision charged to expense	31,786	33,443	549,552
Deconsolidation of Subsidiary January 1, 2010	(364,589)	-	-
Sale of mineral interests	-	-	167,349
End of period balance	$1,155,915	$1,488,718	$1,455,275

Unevaluated property costs, primarily including lease acquisition costs incurred at federal and state lease sales, unevaluated drilling costs, seismic, capitalized interest and certain overhead costs related to exploration and development being excluded from the amortizable evaluated property base, consisted of $3,331 incurred in 2010, $1,621 in 2009, and $3,154 incurred in 2008 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. The Company’s unevaluated property balance of $8,106 at December 31, 2010 reflects a $17,336 decline compared to the December 31, 2009, and primarily relates to the evaluation of the Company’s Gulf of Mexico shelf prospect lease inventory following the Company’s continued shift away from offshore exploration to onshore activities.

Depletion per unit-of-production (Boe) amounted to $19.00, $16.99 and $33.45 for the years ended December 31, 2010, 2009, and 2008, respectively. Lease operating expense, or production costs, per unit-of-production (Boe) amounted to $10.58, $9.37, and $10.03 for the years ended December 31, 2010, 2009, and 2008, 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 based on the preceding 12-months' average oil and gas prices based on closing prices on the first day of each month and require a write-down if the "ceiling" is exceeded. 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 $485,498 impairment of oil and gas properties as a result of the ceiling test calculation.

NOTE 14 – Asset Retirement Obligations

The following table summarizes the activity for the Company's asset retirement obligations:

	For the year ended December 31,	
	2010	2009
Asset retirement obligations at beginning of the period	$14,650	$42,194
Accretion expense	2,446	3,149
Liabilities incurred	608	9
Liabilities settled	(3,035)	(8,194)
Revisions to estimate	1,256	(22,508)
Asset retirement obligations at end of period	15,925	14,650
Less: current asset retirement obligations	(2,822)	(4,002)
Long-term asset retirement obligations at the end of the period	$13,103	$10,648

At December 31, 2010, the Company had $4,443 restricted investment assets, including $399 and $4,044 recorded as current and non-current, respectively. These assets, which primarily include short-term U.S. Government securities, are held in abandonment trusts dedicated to pay future abandonment costs for several of the Company's oil and gas properties.

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NOTE 15 – Supplemental Oil and Gas Reserve Data (unaudited)

The Company's proved oil and gas reserves at December 31, 2010, 2009 and 2008 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 within the continental United States and offshore within the Gulf of Mexico, are as follows:

	Reserve Quantities For the year ended December 31,		
	2010	2009	2008
Proved developed and undeveloped reserves:			
Crude Oil (MBbls):			
Beginning of period	6,479	6,027	24,531
Revisions to previous estimates	423	(356)	(9,026)
Change in ownership	-	563	-
Purchase of reserves in place	-	1,257	-
Sale of reserves in place	-	-	(8,536)
Extensions and discoveries	2,106	-	-
Production	(859)	(1,012)	(942)
End of period	8,149	6,479	6,027
Natural Gas (MMcf):			
Beginning of period	19,103	18,651	116,454
Revisions to previous estimates	354	3,632	(49,526)
Change in ownership	-	420	-
Purchase of reserves in place	-	2,140	-
Sale of reserves in place	-	-	(42,542)
Extensions and discoveries	18,392	-	105
Production	(4,892)	(5,740)	(5,840)
End of period	32,957	19,103	18,651
Proved developed reserves:			
Crude Oil (MBbls):			
Beginning of period	4,346	4,663	4,723
End of period	4,503	4,346	4,663
Natural Gas (MMcf):			
Beginning of period	12,301	13,463	22,340
End of period	12,715	12,301	13,463

Proved undeveloped reserves:			
Crude Oil (MBbls):			
Beginning of period	2,133	1,364	19,808
End of period	3,645	2,133	1,364
Natural Gas (MMcf):			
Beginning of period	6,802	5,188	94,114
End of period	20,241	6,802	5,189

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Notes to the Consolidated Financial Statements
(All amounts in thousands, except per-share, per note, per-hedge and per unit data)

Standardized Measure

The following tables present the standardized measure of future net cash flows related to estimated proved oil and gas reserves together with changes therein, including a reduction for estimated plugging and abandonment costs that are also reflected as a liability on the balance sheet at December 31, 2010. You should not assume that the future net cash flows or the discounted future net cash flows, referred to in the tables below, represent the fair value of our estimated oil and gas reserves. Prior to December 31, 2009, the Company was required to determine estimated future net cash flows using period-end market prices for oil and gas without considering hedge contracts in place at the end of the period. Effective December 31, 2009, the SEC issued a final rule which changed prices used in reserves calculations. Prices are no longer based on a single-day, period-end price. Rather, they are based on either the preceding 12-months' average price based on closing prices on the first day of each month, or prices defined by existing contractual arrangements. The 2010 average 12-month oil and gas prices net of differentials were $78.07 per barrel of oil and $5.10 per Mcf of gas. The 2009 average 12-month oil and gas prices net of differentials were $57.40 per barrel of oil and $4.75 per Mcf of gas. The 2008 year-end oil and gas prices net of differentials were $36.80 per barrel of oil and $6.36 per Mcf of gas. Future production and development costs are based on current costs with no escalations. Estimated future cash flows net of future income taxes have been discounted to their present values based on a 10% annual discount rate.

Gas production from our deepwater and Permian Basin properties has a high BTU content of separator gas. The natural gas Mcf price of $5.10 used in the 2010 reserve estimate reflects estimated revenues from our natural gas and associated natural gas liquids.

	Standardized Measure		
	For the year ended December 31,		
	2010	2009	2008
Future cash inflows	$804,111	$462,607	$340,485
Future costs -			
Production	(277,793)	(195,735)	(192,819)
Development and net abandonment	(146,870)	(50,170)	(34,111)
Future net inflows before income taxes	379,448	216,702	113,555
Future income taxes	(24,719)	(2,809)	(565)
Future net cash flows	354,729	213,893	112,990
10% discount factor	(155,813)	(77,972)	(26,685)
Standardized measure of discounted future net cash flows	$198,916	$135,921	$86,305

	Changes in Standardized Measure		
	For the year ended December 31,		
	2010	2009	2008 (1)
Standardized measure at the beginning of the period	$135,921	$86,305	$1,133,989
Sales and transfers, net of production costs	(72,171)	(82,674)	(122,104)
Net change in sales and transfer prices, net of production costs	126,571	94,435	(111,140)
Net change due to purchases and sales of in place reserves	621	45,009	(558,652)
Extensions, discoveries, and improved recovery, net of future production and development costs incurred	23,739	--	162,566
Changes in future development cost	(68,960)	6,194	33,652
Revisions of quantity estimates	23,295	39,242	(786,001)

Accretion of discount	10,597	5,797	159,147
Net change in income taxes	(5,170)	(2,368)	457,483
Changes in production rates, timing and other	24,473	(56,019)	(282,635)
Aggregate change	62,995	49,616	(1,047,684)
Standardized measure at the end of period	$198,916	$135,921	$86,305

(1) 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 2010 with estimated net proved reserves of 13,642 MBoe, representing a 41% increase over 2009 year-end estimated net proved reserves of 9,663 MBoe. The increase is primarily due to the Company's development of a portion of its Permian Basin and Haynesville Shale properties, on which it drilled a total of 20 oil wells and one natural gas well, respectively.

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 7,019 MBoe of PUDs at December 31, 2010, representing a 115% increase over the 3,266 MBoe of PUDs at December 31, 2009. Of its 2010 PUDs, 1,186 MBoe and 1,148 MBoe 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 Habanero field will be depleted in 2014 and 2013 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 2010.

During 2009, the Company acquired 711 MBbls and 1.3 Bcf, or 928 MBoe, of PUDs in its ExL acquisition. Callon's development plan for these PUDs began during 2010, and is expected to convert all PUDs to PDPs by 2014. The remaining 100 MBoe 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 BOEMRE imposed thresholds. As a result of court decisions, the BOEMRE is no longer enforcing its price thresholds. At year end 2008, the Company had no PUDs located onshore. See Note 16 for additional information related to the royalty relief.

Notes to the Consolidated Financial Statements
(All amounts in thousands, except per-share, per note, per-hedge and per unit data)

NOTE 16 - Bureau of Ocean Energy Management, Regulation and Enforcement (“BOEMRE”) Royalty Recoupment

During 2009, the Company recorded a receivable attributable to a recoupment of royalty payments previously made to the BOEMRE on our deepwater property, Medusa. Following the decisions resulting from several court cases brought by another oil and gas company, the court ruled that the BOEMRE was not entitled to receive these royalty payments. Accordingly, in November 2009 the Company filed for a recoupment of royalties paid to the BOEMRE in the amount of $44,787 from inception-to-date production at the Company’s Medusa field. At December 31, 2009, Callon accrued the royalty recoupment of $44,787 and estimated interest of $7,681. The Company received the recoupment of principal in January 2010, and received $7,927 of interest during the second quarter of 2010, which included additional accrued interest through the repayment date. In addition, the Company is no longer required to make any future royalty payments to the BOEMRE related to its Medusa production.

Royalty recoupment of $2,967 related to 2009 production was recorded as oil and gas sales during the fourth quarter of 2009. For years prior to 2009, royalty recoupment of $40,886 was included in operating revenues as BOEMRE royalty recoupment. Interest income related to the recoupment was recorded as a component of other income and expense.

NOTE 17 – 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 are not expected to 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

NOTE 18 – Summarized Quarterly Financial Information (unaudited)

2010	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Total revenues	$ 23,385	$ 21,569	$ 20,485	$ 24,443
Income from operations	7,040	5,463	4,655	4,021

Net income (loss)	3,923	2,130	1,602	731
Net income (loss) per common share - basic	0.14	0.07	0.06	0.03
Net income (loss) per common share - diluted	0.13	0.07	0.05	0.02

2009	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	
Total revenues	$ 24,815	$ 25,025	$ 21,320	$ 70,985	(a)
Income from operations	8,506	5,731	5,799	53,417	(b)
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	

(a) Includes Medusa royalty recoupment of $43.9 million, net of override, due from the MMS. See Note 17.

(b) Includes Medusa royalty recoupment of $43.9 million, net of override, and estimated interest due from the MMS. See Note 17.

NOTE 19 – Subsequent Events

Equity Offering and Announced Senior Notes Redemption

During February, 2011, the Company received $73,720 in net proceeds through the public offering of 10,100 shares of its common stock, which included the issuance of 1,100 shares pursuant to the underwriters' over-allotment option. The Company intends to use approximately $35,000 of the proceeds to repurchase a portion of its 13% Senior Notes, with the remaining proceeds intended for general corporate purposes including the accelerated development of the Company's Permian Basin and other onshore assets. Immediately following the completion of the equity offering, the Company provided the public notice required by the terms of the Senior Notes to call $31,000 of face value of the Notes. The Company expects to complete the redemption of these notes by March 19, 2011, which will result in a gain on the early extinguishment of debt of $1,974. The gain represents the difference between the $35,030 paid for $37,004 carrying value of the Notes, which included the $31,000 face value of the notes plus $6,004 of accelerated deferred credit amortization, offset by the $4,030 charge related to the 13% call premium required by the terms of the call option.

Arbitration Results

Prior to abandonment of the Entrada project, the Company's joint interest owner in the Entrada Project failed to fund two loan requests totaling $40,000 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 joint interest partner also failed to fund its working interest share of a settlement payment to terminate a drilling contract for the Entrada Project. The Company and its joint interest partner in the Entrada project arbitrated the matter during 2010. During February, 2011, the arbitration panel reviewing the Company's claims against the joint interest owner delivered its final decision in which it ruled that the company was not entitled to recover any damages. The Company determination that the arbitration ruling represented a recognizable subsequent event, and as such, recorded a charge as of December 31, 2010 to write off its $6,597 receivable related to certain joint interest billings not being recovered from a joint interest partner. Under the full cost method of accounting, these costs are capitalized to the Company's full cost pool.

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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

Disclosure Controls and Procedures. Under the supervision and with the participation of our management, including our Chief Executive Officer ("CEO") and Chief Financial Officer ("CFO"), we evaluated the effectiveness of our disclosure controls and procedures (as such term is defined in Rule 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934) as of December 31, 2010. Based upon that evaluation, our CEO and CFO concluded that our disclosure controls and procedures are effective as of December 31, 2010.

Management's Report on Internal Control over Financial Reporting. 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) and 15d-15(f). Under the supervision and with the participation of our management, including our CEO and CFO, we conducted an evaluation of the effectiveness of our internal control over financial reporting as of December 31, 2010 based on the framework in Internal Control – Integrated Framework published by the Committee of Sponsoring Organizations (COSO) of the Treadway Commission. Based on that evaluation, management concluded that our internal control over financial reporting was effective as of December 31, 2010.

Because of its inherent limitations, internal control over financial reporting can provide only reasonable assurance that the objectives of the control system are met and may not prevent or detect misstatements. In addition, any evaluation of the effectiveness of internal controls over financial reporting in future periods is subject to risk that those internal controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

The Company's independent registered public accounting firm has issued an attestation report regarding its assessment of the Company's internal control over financial reporting as of December 31, 2010, which appears on page 73. Additionally, the financial statements for each of the years covered in this Annual Report on Form 10-K have been audited by an independent registered public accounting firm, Ernst & Young LLP whose report is presented page 43 of this Annual Report on Form 10-K.

Changes in Internal Control over Financial Reporting. 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.

ITEM 9A (T). Controls and Procedures

See Item 9A.

ITEM 9B. Other Information

Submissions of Matters to a Vote of the Security Holders

None.

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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, 2010, 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, 2010, 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, 2010 and 2009, 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, 2010 and our report dated ––––March 14, 2011, expressed an unqualified opinion thereon.

/s/Ernst & Young LLP

New Orleans, Louisiana
March 14, 2011

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 12, 2011 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 12, 2011 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 12, 2011 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 12, 2011 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 12, 2011 which will be filed with the Securities and Exchange Commission and is incorporated herein by reference.

PART IV.
ITEM 15. Exhibits

Exhibit			Description
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 42 through 71.		
		Report of Independent Registered Public Accounting Firm Consolidated Balance Sheets as of December 31, 2010 and 2009 Consolidated Statements of Operations for each of the three years in the period ended December 31, 2010 Consolidated Statements of Stockholders' Equity (Deficit) for each of the three years in the Period Ended December 31, 2010 Consolidated Statements of Cash Flows for each of the three years in the period ended December 31, 2010 Notes to Consolidated Financial Statements	
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.		
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 Amendment to the Certificate of Incorporation of the Company
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		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 T3, 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		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)
10.6		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)
10.7		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)
10.8	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)
10.9	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)
10.1	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)
10.11	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)
10.12	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)
10.13	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)
10.14	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)
10.15	Callon Petroleum Company 2010 Phantom Share Plan, adopted May 4, 2010 (incorporated by reference to Exhibit 10.1 of the Company's current Report on Form 8-K filed on May 7, 2010)
10.16	Form of Callon Petroleum Company Phantom Share Award Agreement, adopted May 4, 2010 (incorporated by reference to Exhibit 10.2 of the Company's current Report on Form 8-K filed on May 7 , 2010)
10.17	Deferred Compensation Plan for Outside Directors; Callon Petroleum Company (effective as of January 1, 2011)

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 of Chief Executive and Financial Officers pursuant to Rule 13(a)-14(b)	
99	Additional Exhibits	
99.1		Reserve Report Summary prepared by Huddleston and Co. as of December 31, 2010.
*	Not applicable 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.

Date:	March 14, 2011	/s/ Fred L. Callon Fred L. Callon (principal executive officer, director)
Date:	March 14, 2011	/s/ B. F. Weatherly B. F. Weatherly (principal financial officer, director)
Date:	March 14, 2011	/s/ Rodger W. Smith Rodger W. Smith (principal accounting officer)
Date:	March 14, 2011	/s/ L. Richard Flury L. Richard Flury (director)
Date:	March 14, 2011	/s/ John C. Wallace John C. Wallace (director)
Date:	March 14, 2011	/s/ Richard O. Wilson Richard O. Wilson (director)
Date:	March 14, 2011	/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.

Date:	March 14, 2011	/s/ B. F. Weatherly B. F. Weatherly, Executive Vice President and Chief Financial Officer (Principal Financial Officer)

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