CALLON PETROLEUM CO
Form 10-K
March 15, 2012
UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549
Form 10-K
for the year ended
December 31, 2011

[X]	Annual report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934 For the fiscal year ended December 31, 2011, 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 (State or other jurisdiction of incorporation or organization)	64-0844345 (I.R.S. Employer Identification No.)
200 North Canal Street Natchez, Mississippi (Address of principal executive offices)	39120 (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 [X] No [ ]

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of 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 $260.1 million as of June 30, 2011.

As of March 14, 2012, 39,410,094 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, 2011) relating to the Annual Meeting of Stockholders to be held on May 10, 2012, 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 quantities, present value and 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-K 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 respond to low natural gas prices;
- 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;
- 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, 2011 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.
- Bbl or Bbls: barrel or barrels of oil or natural gas liquids.
- 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. The ratio of one barrel of oil or NGL to six Mcf of natural gas is commonly used in the industry and represents the approximate energy equivalence of oil or NGLs to natural gas, and does not represent the economic equivalency of oil and NGLs to natural gas. The sales price of a barrel of oil or NGLs is considerably higher than the sales price of six Mcf of natural gas.
- Boe/d: Boe per day.
- BLM: Bureau of Land Management.
- BOEM: Bureau of Ocean Energy Management, Regulation and Enforcement; formerly the Minerals Management Service ("MMS").
- Btu: a British thermal unit, a measure of heating value. One Mcf of natural gas generally contains one MMBtu of energy.
- BSEE: Bureau of Safety and Environmental Enforcement.
- EPA: Environmental Protection Agency.
- GHG: greenhouse gases.
- LIBOR: London Interbank Offered Rate.
- Mbbls: thousand barrels of oil.
- Mboe: thousand boe.
- Mboe/d: Mboe per day.
- Mcfe: thousand cubic feet of natural gas equivalents.
- Mcf/d: Mcf per day.
- MMbbls: million barrels of oil.
- MMboe: million boe.
- MMBtu: million Btu.
- MMcf: million cubic feet of natural gas.
- MMcf/d: MMcf per day.
- MMS: Minerals Management Service.
- NGL or NGLs: natural gas liquids, such as ethane, propane, butanes and natural gasoline that are extracted from natural gas production streams.
- NYMEX: New York Mercantile Exchange.
- OCS: outer continental shelf.
- Oil: includes crude oil and condensate.
- ONRR: Office of Natural Resources Revenue.
- PDPs: proved developed producing reserves.
- PDNPs: proved developed non-producing reserves.
- PUDs: proved undeveloped reserves.
- Reserve life: a measurement of the time it will take to produce our proved reserves calculated by dividing our estimate net equivalent reserves at December 31, 2011 by our production during 2011 on an equivalent basis.
- SEC: United States Securities and Exchange Commission.
- 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.

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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 natural 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.

In 2009, the Company began to shift its operational focus from exploration, development and production in the Gulf of Mexico to the acquisition and development of onshore properties located in the Permian Basin in Texas and the Haynesville Shale area in Louisiana. As of December 31, 2011, we had estimated net proved reserves of 10.1 MMbbls and 35.1 Bcf, or 15.9 MMboe. Of these reserves and on an MMboe basis, approximately 61% were located onshore in the Permian Basin and Haynesville Shale plays, compared with approximately 50% located onshore at December 31, 2010.

Well count information is presented gross unless otherwise indicated.

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 natural 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 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:

- Our offshore properties generate substantial cash flow, which we can deploy in the acquisition, exploration and development of onshore properties. Since 2009, we have invested nearly $150 million onshore primarily using offshore cash flows.

- We are replacing Gulf of Mexico Shelf high decline-rate, natural gas production with longer reserve life, liquids-rich production from our onshore drilling programs.

- We have positioned ourselves for further growth by:

Acquiring 14,470 additional net Permian Basin exploration acres in early 2012, which represents a 152% increase over our Permian acreage position at year-end 2011.

Initiating a horizontal oil drilling program on a portion of our Permian acreage scheduled to begin drilling during the second quarter of 2012.

- We have increased reserve life 79% to 8.6 years at year-end 2011 from 4.8 years at year-end 2008.

- Our management team is experienced in oil and natural gas acquisitions, exploration, development and production in the areas in which we focus our operations.

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- On December 31, 2011, our total liquidity position was approximately $88.8 million, including $43.8 million of available cash and $45.0 million of unused borrowing base available under our senior secured credit facility. The borrowing base has increased by 50% over the base at December 31, 2010.

Recent Developments

Subsequent to December 31, 2011, we completed two acreage acquisitions in the northern Midland Basin in Borden County. The northern portion of the Midland Basin has had limited drilling activity compared with the southern portion of the Basin (where our other Permian Basin properties are located), which increases the risk associated with drilling activities on the acquired acreage. Together, these acquisitions included a total of approximately 16,020 gross (14,470, net) acres, and significantly increased our acreage position in the Permian Basin by 152% to a total of 24,010 acres compared to 9,540 acres held year-end 2011. For additional information regarding these acquisitions, please refer to the Onshore Properties portion of this Item 1.

Exploration and Development Activities

During 2011, capital expenditures on an accrual basis for exploration and development costs related to oil and natural gas properties included these expenditures (in millions):

36 wells drilled on the Permian Basin acreage of which 23 wells were producing at year-end	$ 85.3
Leasehold acquisitions and seismic	2.9
Costs incurred on offshore properties	1.8
Plugging and abandonment costs in the Gulf of Mexico	2.6
Capitalized interest	0.7
Capitalized general and administrative costs allocated directly to exploration and development projects	11.9
Total capital expenditures	$ 105.2

With our continued operational focus onshore, primarily in the Permian Basin, we expect that substantially all of our 2012 capital expenditures will be focused on the acquisition, development and operation of onshore properties in the United States, with 10% of capital expenditures directed towards our offshore properties including an up-dip recompletion of the Habanero #2 well. Our projected 2012 capital expenditures budget is discussed in Management's Discussion and Analysis and Results of Operations, which is included in Part II, Item 7 of this filing.

Acquisitions and Divestitures

In addition to the previously discussed 16,020 gross (14,470, net) northern Permian Basin acres we acquired in February 2012, during the second quarter of 2011, we acquired for $2.2 million approximately 1,215 gross (480, net), unevaluated acres in the Pecan Acres field, located in Midland County and in proximity to our Carpe Diem field. Pecan Acres provides 26 gross (10, net) drilling locations, and we are currently operating a rig drilling vertical wells at Pecan Acres. We have drilled and stimulated two Pecan Acres wells, which are currently flowing back after stimulation. Also at Pecan Acres, we have drilled a third well and are currently drilling a fourth, with plans to fracture stimulate these wells in March 2012. During 2012, we plan to drill an additional six wells at Pecan Acres.

Also during 2011, we sold for $2.8 million our Mystic Bayou field, located in south Louisiana. In addition to the proceeds, the acquirer assumed approximately $0.9 million of ARO related to the properties.

Oil and Natural Gas Properties

As of December 31, 2011, our estimated net proved reserves totaled 15.9 MMBoe and included 10.1 MMBbls and 35.1 Bcf, with a pre-tax present value, discounted at 10%, of $309.9 million. Pre-tax present value is a non-US GAAP financial measure, which we reconcile to the US GAAP standardized measure of $270.4 million in note (d) to the table below. Oil constitutes approximately 63% of our total estimated equivalent net proved reserves and approximately 44% of our total estimated equivalent proved developed reserves.

The following table sets forth certain information about our estimated net proved reserves prepared by our independent petroleum reserve engineers by major field and for all other properties combined at December 31, 2011:

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	Operator	Estimated Net Proved Reserves Oil (MBbls)	Natural Gas (MMcf)	Total (MBoe) (a)	Pre-tax Discounted Present Value ($000) (b)(c)(d)
Onshore:					
Permian Basin	Callon	5,631	11,783	7,595	$48,932
Haynesville Shale	Callon	—	12,382	2,064	3,114
Total Onshore		5,631	24,165	9,659	$52,046
Gulf of Mexico Deepwater:					
Mississippi Canyon 538/582 “Medusa”	Murphy	3,810	2,719	4,263	$213,421
Garden Banks Block 341 “Habanero”	Shell	610	4,574	1,373	46,606
Total Gulf of Mexico Deepwater		4,420	7,293	5,636	$260,027
Gulf of Mexico Shelf and Other:					
West Cameron Block 295	Apache	7	1,253	216	$3,563
East Cameron Block 2	Apache	10	639	116	2,398
East Cameron Block 257	Dynamic Offshore	—	754	126	946
Other (c)	Various	7	1,014	175	(9,090)
Total Gulf of Mexico Shelf and Other		24	3,660	633	$(2,183)
Total Net Proved Reserves		10,075	35,118	15,928	$309,890

(a) We convert Mcf to Boe using a conversion ratio of six Mcf to one Bbl. This ratio, which is typical in the industry and represents the approximate energy equivalent of an Mcf to a Bbl, does not reflect to market price equivalence of an Mcf of natural gas compared with a Bbl of oil or NGLs. On an market price equivalence basis, a barrel of oil or NBLs 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, 2011, 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, 2011, in accordance with accounting for asset retirement obligations rules. The negative Pre-Tax Present Value of the “Other” reflects plugging and abandonment obligations exceeding the future net cash flows, with most of such obligations 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, 2011 was $270.4 million inclusive of the $39.5 million discounted estimated future income taxes relating to such future net revenues. The projected per Mcf natural gas price of $5.60 used in the 2011 reserve estimates has been adjusted to reflect the Btu content, transportation charges and other fees specific to the individual properties. The projected per barrel oil price of $98.98 used in the 2011 reserve estimates has been adjusted to reflect all wellhead deductions and premiums on a property-by-property basis, including transportation costs, location differentials and crude quality.

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Onshore Properties

Onshore proved reserves accounted for approximately 61% of year-end 2011 proved reserves on a Boe basis as compared to 50% of 2010 reserves on a Boe basis, demonstrating our strategy of using our offshore cash flow to explore and develop our onshore properties.

Permian Basin

Our primary target in the southern Midland Basin area of the Permian Basin has been the Wolfberry play, which is located on our properties in Crockett, Ector, Midland, and Upton counties, Texas, and which we believe to be a proven, low-risk oil play that includes the Sprayberry, Dean, and Wolfcamp formations. Certain of our southern Midland Basin properties also include the Atoka and Strawn formations. As of December 31, 2011, we owned approximately 9,540 net acres in the Permian Basin. Following two recent acquisitions of acreage on which we will target different formations and as discussed below, the Company increased its ownership within the Basin to approximately 24,010 net acres.

As of December 31, 2011, approximately 48% of the Company's proved reserves were attributable to properties in the Permian Basin. Also as of December 31, 2011, our Permian Basin properties were producing 1,335 Boe/d from 65 wells, of which 31 were placed onto production (and one well taken offline) during 2011. This 2011 exit-rate production represents a 143% increase over the 2010 exit rate of 550 Boe/d producing from 35 wells. Average net production from the Company's Permian Basin properties increased 135% to 965 Boe/d in 2011 from 411 Boe/d in 2010.

Subsequent to December 31, 2011, we significantly expanded our Permian Basin acreage position by acquiring approximately 16,020 gross (14,470, net) exploratory acres in the northern portion of the Midland Basin in Borden County. The northern portion of the Midland Basin has had limited drilling activity compared with the southern portion of the Basin, and therefore has increased risk associated with drilling activities on the acquired acreage. The acquisition costs were funded from existing cash balances. The Company has an average 90% working interest across the contiguous acreage positions and is the operator.

For additional information regarding our Permian Basin properties, including our 2012 capital expenditures program and future development plans for the region, please refer to the Properties discussion within Management's Discussion and Analysis, which is located in Part II, Item 7 of this filing.

Haynesville Shale

Callon holds a 69% working interest in a 624 gross (430, net) acre portion of the Haynesville Shale natural gas unit located in southern Bossier Parish, Louisiana. Initial production from the George R. Mills Well No. 1H, our only well on the property, commenced on September 3, 2010. As of December 31, 2011, the well has produced 2.1 Bcf, and we have an additional six gross (four, net) drilling locations on the acreage. Approximately 13% of our year-end 2011 proved reserves were attributable to our Haynesville Shale property. The Company's one producing Haynesville Shale natural gas well was shut-in for 35 days during the fourth quarter of 2011 due to well interference from an offsetting well. Production was restored in mid-March 2012 following a successful workover.

For additional information regarding the Company's Haynesville Shale property, please refer to the Properties discussion within Management's Discussion and Analysis, which is located in Part II, Item 7 of this filing.

Gulf of Mexico Deepwater Properties

Medusa, Mississippi Canyon Blocks 538/582

Our Medusa deepwater 1999 discovery, 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. Since the field entered production in 2003, cumulative gross volumes have approximated 55 MMBoe.

During 2011, the Medusa field produced 641 MBoe net to Callon from eight wells which accounted for 35% of our total production. Six of the field's wells continue to produce from their initial completions as of December 31, 2011. We project that 1.7 MMBoe of net PDNPs can be accessed by recompletions in the existing wells. These up-hole recompletions in existing wellbores are expected to occur as existing completions deplete to a level that is uneconomic to justify continued production. We anticipate developing another 1.2 MMBoe of net PUDs by drilling an additional well in late 2013. As of December 31, 2011, the current projected economic life of the field is expected to run through 2025.

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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 Part II, Item 7 of this filing under Off-Balance Sheet Arrangements.

Habanero, Garden Banks Block 341

The Habanero field, in which we own an 11.25% working interest, 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. The field is operated by Shell Deepwater Development Inc., which owns a 55% working interest, with the remaining working interest owned by Murphy. Since the field entered production in 2003, cumulative gross volumes have approximated 29 MMBoe.

During 2011, Habanero produced 197 MBoe net to Callon from two wells accounting for 11% of our total production. Our plans include in the fourth quarter of 2012 the development of PUDs by a sidetrack of the Habanero #2 well. As of December 31, 2011, the Company expects to reach the economic life of the field in 2019.

For additional information regarding the Company's Deepwater properties, please refer to the Properties discussion within Management's Discussion and Analysis, which is located in Part II, Item 7 of this filing.

Gulf of Mexico Shelf and Other Properties

We own interests in 18 producing wells in 11 oil and natural gas fields in the shelf area of the Gulf of Mexico. These wells produced 551 MBoe net to our interest in 2011, which accounted for 30% of our total production. For additional information regarding the Company's Shelf and other properties, please refer to the Properties discussion within Management's Discussion and Analysis, which is located in Part II, Item 7 of this filing.

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, 2010 and 2011 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, including NGLs, 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 net 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.

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	Years Ended December 31,		
	2011	2010	2009
Proved developed:			
Oil (MBbls)	5,069	4,503	4,346
Natural Gas (MMcf)	11,605	12,715	12,301
MBoe	7,003	6,622	6,396
Proved undeveloped:			
Oil (MBbls)	5,006	3,645	2,133
Natural Gas (MMcf)	23,513	20,241	6,802
MBoe	8,925	7,019	3,266
Total proved:			
Oil (MBbls)	10,075	8,149	6,479
Natural Gas (MMcf)	35,118	32,957	19,103
MBoe	15,928	13,641	9,663
Estimated pre-tax future net cash flows [a]	$568,798	$379,448	$216,702
Pre-tax discounted present value [a] [b]	$309,890	$205,532	$137,368
Standardized measure of discounted future net cash flows[a] [b]	$270,357	$198,916	$135,921

(a) Includes a reduction for estimated plugging and abandonment costs that is reflected as a liability on our balance sheet at December 31, 2011, in accordance with accounting for asset retirement obligations rules.

(b) 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, 2011 was $270.4 million inclusive of the $39.5 million discounted estimated future income taxes relating to such future net revenues. The natural gas Mcf prices of $5.60 used in the 2011 reserve estimates have been adjusted to reflect the Btu content, transportation charges and other fees specific to the individual properties. The projected oil prices of $98.98 used in the 2011 reserve estimates have been adjusted to reflect all wellhead deductions and premiums on a property-by-property basis, including transportation costs, location differentials and crude quality.

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

Annually, the Company reviews its PUDs to ensure an appropriate plan exists for development. Except as noted below, reserves 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 basis for our development plans are (i) allocation of capital to projects in our 2012 capital budget and (ii) in subsequent years, on the basis of capital allocation in our 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.

The following table summarizes the Company's recorded PUDs:

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	PUDs (MBoe) at December 31,		
	2011	2010	2009
Permian Basin	4,861	2,928	932
Haynesville Shale	1,730	1,757	—
Total Onshore PUDs	6,591	4,685	932
Medusa	1,186	1,186	1,186
Habanero	1,148	1,148	1,148
Total Deepwater PUDs	2,334	2,334	2,334
Total Shelf and other PUDs	—	—	—
Total PUDs	8,925	7,019	3,266

Our 2,334 MBoe of deepwater PUDs have been classified as PUDs for more than five years, though we expect to develop these PUDs within the next two years. Our decision to classify these reserves as PUDs was primarily based on (1) our ongoing development activities in the area, (2) our historical record of completing development of comparable long-term projects, (3) the amount of time which we have maintained the leases or booked reserves without significant development activities and (4) the extent to which we have followed previously adopted development plans. Our discussions with the field's operator have resulted in the modification of certain development plans for both Medusa and Habanero to drill or sidetrack PUDs within a shorter period of time than originally estimated. The Company currently forecasts that one of the two producing wells in the Habanero field will deplete in 2012, and the field operator has provided notice that the well will be sidetracked to a location with PUD reserves of 1,148 Mboe in the fourth quarter of 2012. Within the Medusa field and to access the PUD reserves of 1,186 MBoe, the Company expects to drill a new well in 2013. During 2011, the Company did not convert any offshore PUDs to PDPs.

The Company's plans to develop its onshore, Permian Basin PUDs include a multi-year drilling program, which is expected to be completed on existing acreage within five years. Similarly, the Company plans to resume drilling on its Haynesville field, and expects to convert its existing PUDs within the next four years.

The Company's PUDs increased 27% to 8,925 MBoe from 7,019 MBoe at December 31, 2011 and 2010, respectively. Additions during the year added 2,988 MBoe to the Company's PUDs, offset by 1,082 MBoe primarily comprised of transfers to PDPs as a result of our development program. None of these additions to our PUD reserves were offset by amounts no longer deemed to be economic PUDs at year-end. Revisions to PUDs were not material in 2011. Of our year-end 2010 PUD reserves, 13% were converted to proved developed producing reserves by year end 2011, at a total cost of $28.5 million, net.

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 has over 30 years of industry experience including 25 years as a manager and 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. Huddleston's reserve report letter 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.

The 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 natural gas reserves.

Production Volumes, Average Sales Prices and Average Production Costs

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

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	Years Ended December 31,		
	2011	2010	2009
	(in thousands, except per unit data)		
Production			
Natural gas and NGLs (Mcf)	5,081	4,892	5,740
Oil (MBbl)	996	859	1,012
Total (MBoe)	1,843	1,674	1,969
Revenues			
Natural gas and NGL sales	$26,682	$24,639	27,417
Oil sales	100,962	65,243	73,842
Total revenues	$127,644	$89,882	$101,259
Lease Operating Expenses			
Production costs	$17,929	$16,094	$16,778
Severance/production taxes	1,826	816	528
Gathering	592	802	1,141
Total lease operating expenses	$20,347	$17,712	$18,447
Realized prices			
Natural gas ($/Mcf, including realized gains (losses) on derivatives) (a)	$5.25	$5.04	$4.78
Natural gas ($/Mcf, excluding realized gains (losses) on derivatives) (a)	5.25	4.91	4.45
Oil ($/Bbl, including realized gains (losses) on derivatives) (b)	101.34	75.97	73.00
Oil ($/Bbl, excluding realized gains (losses) on derivatives) (b)	101.72	75.97	55.84
Operating costs per Boe - Total Consolidated			
Production costs	$9.73	$9.61	$8.52
Severance/production taxes	0.99	0.49	0.27
Gathering	0.32	0.48	0.58
DD&A	26.42	19.00	16.99
Interest	6.36	7.95	9.70
Total operating costs per Boe	$43.82	$37.53	$36.06

(a) Natural gas prices exceeded the related NYMEX prices, which are quoted on an MMBtu basis, primarily due to the value of the NGLs in our liquids-rich natural gas stream, primarily from our Permian Basin and deepwater production.

(b) Oil prices for production from our two deepwater fields reflect a premium over NYMEX pricing based on Mars WTI differential for Medusa production and Argus Bonita WTI differential for Habanero production.

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, 2011, the Company was in the process of drilling two development wells (which are excluded from the table below) and had nine development oil wells (which are included in the table below) awaiting fracture stimulation including seven first-time well stimulations.

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	Years ended December 31,					
	2011		2010		2009	
	Gross	Net	Gross	Net	Gross	Net
Development:						
Oil	36	32.77	20	19.37	—	—
Natural Gas	—	—	1	0.69	—	—
Non-productive	—	—	—	—	—	—
Total	36	32.77	21	20.06	—	—
Exploration: (a)						
Oil	—	—	—	—	—	—
Natural Gas	—	—	—	—	—	—
Non-productive	—	—	—	—	—	—
Total	—	—	—	—	—	—

(a) Our wells have been drilled within the productive boundaries of statistical plays, and are therefore classified as development well.

The following table sets forth productive wells as of December 31, 2011:

	Oil Wells		Natural Gas Wells	
	Gross	Net	Gross	Net
Working interest	75	60.70	12	5.52
Royalty interest	3	0.10	5	0.13
Total	78	60.80	17	5.65

A well is categorized as an oil well or a natural gas well based upon the ratio of oil to natural gas reserves on a Mcfe basis. However, some of our wells produce both oil and natural gas.

For the periods reflected, the following table sets forth by major field(s) net production volumes and estimated proved reserves:

	Year ended December 31,								
	2011			2010			2009		
	Production Volumes (MBoe)	% of Total Proved Reserves		Production Volumes (MBoe)	% of Total Proved Reserves		Production Volumes (MBoe)	% of Total Proved Reserves	
Offshore - Gulf of Mexico:									
Medusa	641	27	%	593	33	%	751	51	%
Habanero	197	8	%	233	10	%	370	16	%
Shelf and other	551	4	%	616	7	%	829	17	%
Total offshore:	1,389	39	%	1,442	50	%	1,950	84	%
Onshore:									
Permian Basin	353	48	%	150	33	%	19	16	%
Haynesville natural gas shale	101	13	%	82	17	%	—	—	%
Total onshore:	454	61	%	232	50	%	19	16	%
Total	1,843	100	%	1,674	100	%	1,969	100	%

Leasehold Acreage

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

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2011.

	Developed		Undeveloped		Total	
	Gross	Net	Gross	Net	Gross	Net
Louisiana	2,519	965	901			