CABOT OIL & GAS CORP
Form 10-K
February 28, 2012

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D. C. 20549

FORM 10-K

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

For the fiscal year ended December 31, 2011

Commission file number 1-10447

CABOT OIL & GAS CORPORATION

(Exact name of registrant as specified in its charter)

Delaware	**04-3072771**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification Number)

Three Memorial City Plaza 840 Gessner Road, Suite 1400 Houston, Texas 77024
(Address of principal executive offices including ZIP code)

(281) 589-4600
(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, par value $.10 per share	New York Stock Exchange

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

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ý No o

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

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months and (2) has been subject to such filing requirements for the past 90 days. Yes ý No o

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ý No o

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K ý.

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

Large accelerated filer ý	Accelerated filer o	Non-accelerated filer o (Do not check if a smaller reporting company)	Smaller reporting company o

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

The aggregate market value of Common Stock, par value $.10 per share ("Common Stock"), held by non-affiliates as of the last business day of registrant's most recently completed second fiscal quarter (based upon the closing sales price on the New York Stock Exchange on June 30, 2011) was approximately $6.9 billion.

As of February 17, 2012, there were 209,826,622 shares of Common Stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Proxy Statement for the Annual Meeting of Stockholders to be held May 1, 2012 are incorporated by reference into Part III of this report.

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The statements regarding future financial and operating performance and results, strategic pursuits and goals, market prices, future hedging activities, and other statements that are not historical facts contained in this report are forward-looking statements. The words "expect," "project," "estimate," "believe," "anticipate," "intend," "budget," "plan," "forecast," "predict," "may," "should," "could," "will" and similar expressions are also intended to identify forward-looking statements. These statements involve risks and uncertainties, including, but not limited to, market factors, market prices (including geographic basis differentials) of natural gas and oil, results of future drilling and marketing activity, future production and costs, legislative and regulatory initiatives, electronic, cyber or physical security breaches and other factors detailed in this document and in our other Securities and Exchange Commission filings. See "Risk Factors" in Item 1A for additional information about these risks and uncertainties. If one or more of these risks or uncertainties materialize, or if underlying assumptions prove incorrect, actual outcomes may vary materially from those included in this document. See "Forward-Looking Information" for further details.

GLOSSARY OF CERTAIN OIL AND GAS TERMS

The following are abbreviations and definitions of certain terms commonly used in the oil and gas industry and included within this Annual Report on Form 10-K:

Abbreviations

Bbl. One stock tank barrel, or 42 U.S. gallons liquid volume, used in reference to oil or other liquid hydrocarbons.

Bcf. One billion cubic feet of natural gas.

Bcfe. One billion cubic feet of natural gas equivalent.

Mbbls. One thousand barrels of oil or other liquid hydrocarbons.

Mcf. One thousand cubic feet of natural gas.

Mcfe. One thousand cubic feet of natural gas equivalent.

Mmbtu. One million British thermal units.

Mmcf. One million cubic feet of natural gas.

Mmcfe. One million cubic feet of natural gas equivalent.

NGL. Natural gas liquids.

NYMEX. New York Mercantile Exchange.

Definitions

Developed reserves. Developed reserves are reserves that can be expected to be recovered: (i) Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and (ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

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

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Differential. An adjustment to the price of oil or gas from an established spot market price to reflect differences in the quality and/or location of oil or gas.

Dry Hole. Exploratory or development well that does not produce oil or gas in commercial quantities.

Exploitation activities. The process of the recovery of fluids from reservoirs and drilling and development of oil and gas properties.

Exploratory well. A well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir. Generally, an exploratory well is any well that is not a development well, an extension well, or a service well.

Extension well. An extension well is a well drilled to extend the limits of a known reservoir.

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

Oil. Crude oil and condensate.

Operator. The individual or company responsible for the exploration, development and/or production of an oil or gas well or lease.

Production costs. Costs incurred to operate and maintain wells and related equipment and facilities, including depreciation and applicable operating costs of support equipment and facilities, which become part of the cost of oil and gas produced.

Proved properties. Properties with proved reserves.

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

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

Recompletion. An operation whereby a completion in one zone is abandoned in order to attempt a completion in a different zone within the existing wellbore.

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

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oil and gas or related substances to market, and all permits and financing required to implement the project.

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

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

Royalty interest. An interest in an oil and gas lease that gives the owner of the interest the right to receive a portion of the production from the leased acreage (or of the proceeds of the sale thereof), but generally does not require the owner to pay any portion of the costs of drilling or operating the wells on the leased acreage. Royalties may be either landowner's royalties, which are reserved by the owner of the leased acreage at the time the lease is granted, or overriding royalties, which are usually reserved by an owner of the leasehold in connection with a transfer to a subsequent owner.

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

Standardized measure. The present value, discounted at 10% per year, of estimated future net revenues from the production of proved reserves, computed by applying sales prices used in estimating proved oil and gas reserves to the year-end quantities of those reserves in effect as of the dates of such estimates and held constant throughout the productive life of the reserves (except for consideration of future price changes to the extent provided by contractual arrangements in existence at year-end), and deducting the estimated future costs to be incurred in developing, producing and abandoning the proved reserves (computed based on year-end costs and assuming continuation of existing economic conditions). Future income taxes are calculated by applying the appropriate year-end statutory federal and state income tax rate with consideration of future tax rates already legislated, to pre-tax future net cash flows, net of the tax basis of the properties involved and utilization of available tax carryforwards related to proved oil and gas reserves.

Undeveloped reserves. Undeveloped reserves are reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required. Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence exists that establishes reasonable certainty of economic producibility at greater distances. Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances justify a longer time. Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, or by other evidence using reliable technology establishing reasonable certainty.

Unproved properties. Properties with no proved reserves.

Working interest. An interest in an oil and gas lease that gives the owner of the interest the right to drill for and produce oil and gas on the leased acreage and requires the owner to pay a share of the costs of drilling and production operations.

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PART I

ITEMS 1 and 2. BUSINESS AND PROPERTIES

Cabot Oil & Gas Corporation is an independent oil and gas company engaged in the development, exploitation and exploration of oil and gas properties. Our primary areas of operation include Appalachia, east and south Texas, and Oklahoma. Our assets are concentrated in areas with known hydrocarbon resources, which are conducive to multi-well, repeatable drilling programs. We operate in one segment, natural gas and oil development, exploitation and exploration, exclusively in the continental United States. We have regional offices located in Houston, Texas and Pittsburgh, Pennsylvania.

OVERVIEW

On an equivalent basis, our production in 2011 increased by 44% from 2010. We produced 187.5 Bcfe, or 513.7 Mmcfe per day, in 2011, as compared to 130.6 Bcfe, or 357.9 Mmcfe per day, in 2010. Natural gas production increased by 53.4 Bcf, or 43%, to 178.8 Bcf in 2011 from 125.5 Bcf in 2010, primarily due to increased production in the Marcellus shale associated with our increased drilling program and upgrades to the Lathrop compressor station in Susquehanna County, Pennsylvania, which included the commissioning of new compression during 2011. Partially offsetting the production increase in northeast Pennsylvania were decreases in production primarily in east and south Texas due to normal production declines, the sale of oil and gas properties in Colorado, Utah and Wyoming and a shift from gas to oil projects. Crude oil/condensate/NGL production increased by 584 Mbbls, or 68%, from 859 Mbbls in 2010 to 1,443 Mbbls in 2011 primarily due to an increase in production resulting from our Eagle Ford oil shale drilling program in south Texas.

Our average realized natural gas price for 2011 was $4.46 per Mcf, 22% lower than the $5.69 per Mcf price realized in 2010. Our average realized crude oil price for 2011 was $90.49 per Bbl, 8% lower than the $97.91 per Bbl price realized in 2010. These realized prices include realized gains and losses resulting from commodity derivatives. For information about the impact of these derivatives on realized prices, refer to "Results of Operations" in Item 7.

Our proved reserves totaled approximately 3,033 Bcfe at December 31, 2011, of which 96% were natural gas. This reserve level was up by 12% from 2,701 Bcfe at December 31, 2010 on the strength of results from our drilling program. In 2011, we had a net upward revision of 21.6 Bcfe, which was primarily due to an upward performance revision of 214.9 Bcfe, primarily in the Dimock field in northeast Pennsylvania, partially offset by a downward revision of 189.8 Bcfe of proved undeveloped reserves that are no longer in our five-year development plan and a downward revision of 3.6 Bcfe associated with decreased reserve commodity pricing. For information about other changes in our proved reserves, refer to the Supplemental Oil and Gas Information to the Consolidated Financial Statements included in Item 8.

For the year ended December 31, 2011, we drilled 161 gross wells (96.0 net) with a success rate of over 99% compared to 113 gross wells (87.1 net) with a success rate of 98% for the prior year. In 2012, we plan to drill approximately 120 to 130 gross wells, focusing our capital program in the Marcellus shale in northeast Pennsylvania, the Eagle Ford oil shale in south Texas and the Marmaton oil play in Oklahoma.

Our 2011 total capital and exploration spending was $905.5 million compared to $891.5 million in 2010. This increase in spending was substantially driven by an expanded Marcellus shale horizontal drilling program and increases in our drilling programs in the Eagle Ford oil shale in south Texas and the Marmaton oil play in Oklahoma. In both 2011 and 2010, we allocated our planned program for capital and exploration expenditures among our various operating areas based on return expectations, availability of services and human resources. We plan to continue such method of allocation in 2012.

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Funding of the program is expected to be provided by operating cash flow, existing cash and, if required, borrowings under our credit facility. In 2012, we plan to spend between $750 and $790 million on capital and exploration activities.

While we consider acquisitions from time to time, we remain focused on pursuing drilling opportunities that provide more predictable results on our accumulated acreage position. Additionally, we intend to maintain spending discipline and manage our balance sheet in an effort to ensure sufficient liquidity, including cash resources and available credit. We believe these strategies are appropriate for our portfolio of projects in the current commodity pricing environment and will continue to add shareholder value over the long-term.

DIVESTITURES

In October 2011, we sold certain proved oil and gas properties located in Colorado, Utah and Wyoming to Breitburn Energy Partners, L.P. for $285.0 million. We received $283.2 million in cash proceeds, after closing adjustments, and recognized a $4.2 million gain on sale of assets.

In May 2011, we sold certain of our unproved Haynesville and Bossier Shale oil and gas properties in east Texas to a third party. We received approximately $47.0 million in cash proceeds and recognized a $34.2 million gain on sale of assets.

In 2011, we sold various other unproved properties and other assets for total proceeds of $73.5 million and recognized an aggregate gain of $25.0 million.

In December 2010, we sold our existing Pennsylvania gathering infrastructure of approximately 75 miles of pipeline and two compressor stations to Williams Field Services (Williams), a subsidiary of Williams Partners L.P., for $150 million. Under the terms of the purchase and sale agreement, we were obligated to construct pipelines to connect certain of our 2010 program wells, complete the construction of the Lathrop compressor station and complete taps into certain pipeline delivery points. These obligations were completed in 2011. As of December 31, 2010, we recognized a $49.3 million gain on sale of assets, which included the accrual of $17.9 million associated with the obligations described above. We also entered into a 25-year firm gathering contract with Williams that requires Williams to complete construction of approximately 32 miles of high pressure pipeline, 65 miles of trunklines and two compressor stations in Susquehanna County, Pennsylvania in 2011 and 2012. Additionally, Williams will connect all of our drilling program wells, which will connect our production to five interstate pipeline delivery options.

In 2010, we sold various other proved and unproved properties and other assets for total proceeds of $32.2 million and recognized an aggregate gain of $16.3 million.

In April 2009, we sold substantially all of our Canadian proved oil and gas properties to Tourmaline Oil Corporation (Tourmaline) in exchange for cash and common shares of Tourmaline. In November 2010, we sold our investment in Tourmaline for $61.3 million and recognized a $40.7 million gain on sale of assets.

DESCRIPTION OF PROPERTIES

Our properties are primarily located in Appalachia, east and south Texas and Oklahoma. Our activities in Appalachia are concentrated primarily in northeast Pennsylvania and in West Virginia. There are multiple producing intervals in Appalachia that includes the Devonian (including Marcellus), Big Lime, Weir and Berea shale formations at depths primarily ranging from approximately 950 to 7,800 feet, with an average depth of approximately 4,375 feet. Principal producing intervals in east Texas are in the Cotton Valley, Haynesville, Bossier, and James Lime formations and the principal producing intervals in south Texas are in the Eagle Ford, Frio, Vicksburg and Wilcox formations, with total depths ranging from approximately 2,650 to 19,650 feet, with an average depth of approximately

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11,150 feet. Our activities in Oklahoma include the Marmaton, Chase, Morrow and Chester formations in the Anadarko Basin at depths ranging from approximately 2,350 to 18,630 feet, with an average depth of approximately 10,490 feet. We also hold undeveloped acreage in the Rocky Mountains, located in Montana and Nevada.

Ancillary to our exploration, development and production operations, we operate a number of gas gathering and transmission pipeline systems, made up of approximately 3,105 miles of pipeline with interconnects to three interstate transmission systems and five local distribution companies and numerous end users as of the end of 2011. The majority of our pipeline infrastructure is located in West Virginia and is regulated by the Federal Energy Regulatory Commission (FERC) for interstate transportation service and the West Virginia Public Service Commission (WVPSC) for intrastate transportation service. As such, the transportation rates and terms of service of our pipeline subsidiary, Cranberry Pipeline Corporation, are subject to the rules and regulations of the FERC and the WVPSC. Our natural gas gathering and transmission pipeline systems in West Virginia enable us to connect new wells quickly and to transport natural gas from the wellhead directly to interstate pipelines, local distribution companies and industrial end users. Control of our gathering and transmission pipeline systems also enables us to purchase, transport and sell natural gas produced by third parties. In addition, we can engage in development drilling without relying upon third parties to transport our natural gas and incur only the incremental costs of pipeline and compressor additions to our system.

We also have two natural gas storage fields located in West Virginia with a combined working capacity of approximately 4 Bcf. We use these storage fields to take advantage of the seasonal variations in the demand for natural gas typically associated with winter natural gas sales, while maintaining production at a nearly constant rate throughout the year. The pipeline systems and storage fields are fully integrated with our operations.

MARKETING

The principal markets for our natural gas are in the northeastern and midwestern United States and the industrialized Gulf Coast area. In the northeastern United States, we sell natural gas to industrial customers, local distribution companies and gas marketers both on and off our pipeline and gathering system. In the Gulf Coast area and the midwestern United States, we sell natural gas to intrastate pipelines, natural gas processors and marketing companies. Properties in the Gulf Coast area are connected to various processing plants in Texas and Louisiana with multiple interstate and intrastate deliveries, affording us access to multiple markets.

Approximately 35-40% of our natural gas sales volume in 2011 was sold at index-based prices under contracts with terms of one year or greater. Our remaining natural gas sales volume was sold under contracts with terms less than one year. Spot market sales are made at index-based prices under month-to-month contracts, while industrial and utility sales generally are made under year-to-year contracts.

In 2011, we produced and marketed approximately 490.0 Mmcf per day of natural gas and 4.0 Mbbls of crude oil/condensate/NGL per day at market responsive prices. Average daily production in 2011 was 513.7 Mmcfe. Natural gas and crude oil/condensate/NGL production for 2011 was 178.8 Bcf and 1,443 Mbbls, respectively.

In February 2012, we entered into a Precedent Agreement with Constitution Pipeline Company, LLC, a wholly owned subsidiary of Williams Partners L.P., to develop and construct a large diameter pipeline to transport our production in northeast Pennsylvania to both the New England and New York markets. Under the terms of the agreement, we will own 500,000 Mcf per day of capacity on the newly constructed pipeline and acquire a 25% equity interest in the project, subject to certain terms and conditions yet to be determined and regulatory approval.

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RISK MANAGEMENT

From time to time, when we believe that market conditions are favorable, we use certain derivative financial instruments to manage price risks associated with our production. While there are many different types of derivatives available, we utilized natural gas and crude oil swap agreements and crude oil collar agreements for portions of our 2011 production to attempt to manage price risk more effectively. During 2011, we also entered into crude oil swaps to hedge our price exposure on our 2012 production, natural gas swaps to hedge our price exposure on our 2011 and 2012 production and natural gas collars to hedge our price exposure on our 2013 production. In addition, we also have natural gas basis swaps covering a portion of anticipated 2012 production, which do not qualify for hedge accounting. In 2010 and 2009, we utilized collars and swaps to hedge our price exposure on our production.

The collar arrangements are put and call options used to establish floor and ceiling commodity prices for a fixed volume of production during a certain time period. They provide for payments to counterparties if the index price exceeds the ceiling and payments from the counterparties if the index price falls below the floor. The price swaps call for payments to, or receipts from, counterparties based on whether the market price of natural gas or crude oil for the period is greater or less than the fixed price established for that period when the swap is put in place.

For 2011, swaps covered 42% of natural gas production and 20% of crude oil production at a weighted-average price of $5.30 per Mcf and $106.20 per Bbl, respectively, and collars covered 26% of crude oil production at a weighted-average price of $90.88 per Bbl.

As of December 31, 2011, we had the following outstanding commodity derivatives:

Commodity and Derivative Type	Weighted-Average Contract Price	Volume	Contract Period
Derivatives Designated as Hedging			
Natural Gas Swaps	$5.22 per Mcf	95,998 Mmcf	Jan. 2012 - Dec. 2012
Natural Gas Collars	$6.20 Ceiling/ $5.15 Floor per Mcf	17,729 Mmcf	Jan. 2013 - Dec. 2013
Crude Oil Swaps	$98.28 per Bbl	732 Mbbl	Jan. 2012 - Dec. 2012
Derivatives Not Designated as Hedging Instruments			
Natural Gas Basis Swaps	$(0.27) per Mcf	17,042 Mmcf	Jan. 2012 - Dec. 2012

We will continue to evaluate the benefit of employing derivatives in the future. Please read "Management's Discussion and Analysis of Financial Condition and Results of Operations" and "Quantitative and Qualitative Disclosures about Market Risk" for further discussion concerning our use of derivatives.

RESERVES

Our reserve estimates were based on decline curve extrapolations, material balance calculations, volumetric calculations, analogies, or combinations of these methods for each well, reservoir or field. The proved reserve estimates presented herein were prepared by our petroleum engineering staff and audited by Miller and Lents, Ltd., independent petroleum engineers. Miller and Lents made independent estimates for 100% of the proved reserves estimated by us and concluded the following: In their judgment we have an effective system for gathering data and documenting information required to estimate our proved reserves and project our future revenues. Further, Miller and Lents has concluded (1) the reserves estimation methods employed by us were appropriate, and our classification of such reserves was appropriate to the relevant SEC reserve definitions, (2) our reserves estimation processes were comprehensive and of sufficient depth, (3) the data upon which we relied were adequate and of sufficient quality, and (4) the results of our estimates and projections are, in the aggregate, reasonable. For additional information regarding estimates of proved reserves, the audit of such estimates by Miller

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and Lents, Ltd., and other information about our oil and gas reserves, see the Supplemental Oil and Gas Information to the Consolidated Financial Statements included in Item 8. A copy of the audit letter by Miller and Lents, Ltd., dated January 31, 2012, has been filed as an exhibit to this Form 10-K.

Our reserves are sensitive to natural gas and crude oil sales prices and their effect on the economic productive life of producing properties. Our reserves are based on 12-month average oil and gas index prices, calculated as the unweighted arithmetic average for the first day of the month price for each month during 2011, 2010 and 2009, respectively. Increases in commodity prices may result in a longer economic productive life of a property or result in more economically viable proved undeveloped reserves to be recognized. Decreases in prices may result in negative impacts of this nature.

Internal Control

Our corporate reservoir engineers report to the Vice President of Engineering and Technology, who maintains oversight and compliance responsibility for the internal reserve estimation process and provides oversight for the annual audit of our year-end reserves by our independent third party engineers, Miller and Lents, Ltd. Our corporate reservoir engineering group consists of four petroleum/chemical engineers, with petroleum/chemical engineering degrees and between one and 29 years of industry experience, between one and 29 years of reservoir engineering/management experience, and between one and 13 years managing our reserves. All four engineers are members of the Society of Petroleum Engineers.

Qualifications of Third Party Engineers

The technical person primarily responsible for the audit of our reserve estimates at Miller and Lents, Ltd. meets the requirements regarding qualifications, independence, objectivity, and confidentiality set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers. Miller and Lents, Ltd. is an independent firm of petroleum engineers, geologists, geophysicists, and petro physicists; they do not own an interest in our properties and are not employed on a contingent fee basis.

For additional information about the risks inherent in our estimates of proved reserves, see "Risk Factors Our proved reserves are estimates. Any material inaccuracies in our reserve estimates or underlying assumptions could cause the quantities and net present value of our reserves to be overstated or understated" in Item 1A.

Proved Undeveloped Reserves

At December 31, 2011 we had 1,233.1 Bcfe of proved undeveloped reserves, which represents an increase of 256.2 Bcfe compared with December 31, 2010. For 2011, total capital related to the development of proved undeveloped reserves was $284.5 million, resulting in the conversion of 228.7 Bcfe of reserves to proved developed. During 2011, we had 556.3 Bcfe of proved undeveloped reserve additions and 161.7 Bcfe of positive proved undeveloped reserve performance revisions, primarily in the Dimock field in northeast Pennsylvania. These increases were partially offset by sales of proved undeveloped reserves of 43.3 Bcfe located in Colorado, Utah, Wyoming and east Texas and the removal of 189.8 Bcfe of proved undeveloped reserves associated with drilling locations, primarily in east Texas, West Virginia and Oklahoma, no longer anticipated to be developed within the next five years primarily due to a continued shift in our drilling program.

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Historical Reserves

The following table presents our estimated proved reserves for the periods indicated.

	As of December 31,		
	2011	**2010**	**2009**
Natural Gas *(Mmcf)*			
Proved Developed Reserves	**1,734,088**	1,681,451	1,288,169
Proved Undeveloped Reserves	**1,175,828**	962,707	724,993
	2,909,916	2,644,158	2,013,162
Crude Oil & Liquids *(Mbbl)*			
Proved Developed Reserves	**10,922**	7,129	6,082
Proved Undeveloped Reserves(1)	**9,548**	2,362	1,701
	20,470	9,491	7,783
Natural Gas Equivalent *(Mmcfe)*(2)	**3,032,735**	2,701,102	2,059,858
Reserve Life *(in years)*(3)	**16.2**	20.7	20.0

(1) *Proved undeveloped reserves for 2011 include 132.4 Bcfe of reserves drilled but awaiting completion.*

(2) *Natural gas equivalents are determined using a ratio of 6 Mcf of natural gas to 1 Bbl of crude oil, condensate or natural gas liquids.*

(3) *Reserve life index is equal to year-end reserves divided by annual production for the year ended December 31, 2011, 2010 and 2009, respectively.*

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Production, Sales Price and Production Costs

The following table presents historical information about our production volumes for natural gas and crude oil (including condensate and natural gas liquids), average natural gas and crude oil realized sales prices, and average production costs per equivalent, including our Dimock field located in northeast Pennsylvania, which contains more than 15% of our total proved reserves.

	Year Ended December 31,		
	2011	**2010**	**2009**
Production Volumes			
Natural Gas *(Bcf)*			
Dimock Field	**119.3**	49.5	36.3
Total	**178.8**	125.5	98.0
Crude Oil/Condensate/NGL *(Mbbl)*			
Dimock Field			
Total	**1,443**	859	845
Equivalents *(Bcfe)*			
Dimock Field	**119.3**	49.5	36.3
Total	**187.5**	130.7	103.0
Natural Gas Average Sales Price *($/Mcf)*[1]			
Dimock Field	**$ 3.85**	$ 4.48	$ 4.19
Total	**4.46**	5.69	7.61
Crude Oil Average Sales Price *($/Bbl)*[1]			
Dimock Field	**$**	$	$
Total	**90.49**	97.91	85.52
Average Production Costs *($/Mcfe)*			
Dimock Field	**$ 0.08**	$ 0.08	$ 0.03
Total	**0.47**	0.89	1.08

(1) *Represents the average realized sales price for all production volumes and royalty volumes sold during the periods shown, net of related costs (principally purchased gas royalty). Includes realized impact of derivative instruments.*

Acreage

Our interest in both developed and undeveloped properties is primarily in the form of leasehold interests held under customary mineral leases. These leases provide us the right, in general, to develop oil and/or natural gas on the properties. Their primary terms range in length from approximately three to 10 years. These properties are held for longer periods if production is established.

The following table summarizes our gross and net developed and undeveloped leasehold and mineral fee acreage at December 31, 2011. Acreage in which our interest is limited to royalty and overriding royalty interests is excluded.

	Developed		Undeveloped		Total	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
Leasehold Acreage	1,139,459	956,384	846,643	698,787	1,986,102	1,655,171
Mineral Fee Acreage	133,622	112,234	61,744	52,242	195,366	164,476
Total	**1,273,081**	**1,068,618**	**908,387**	**751,029**	**2,181,468**	**1,819,647**

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Total Net Undeveloped Acreage Expiration

Our net undeveloped acreage expiring over the next three years as of December 31, 2011 is 128,463, 197,514 and 51,518 for the years ending December 31, 2012, 2013 and 2014, respectively. These amounts assume no future successful development or renewal of undeveloped acreage.

Well Summary

The following table presents our ownership in productive natural gas and oil wells at December 31, 2011. This summary includes natural gas and oil wells in which we have a working interest.

	Gross	Net
Natural Gas	5,091	4,325.9
Crude Oil	226	176.1
Total[(1)(2)]	**5,317**	**4,502.0**

(1) *Total excludes 55 (52.3 net) service wells.*

(2) *Total percentage of gross operated wells is 89.0%.*

Drilling Activity

We drilled wells, participated in the drilling of wells, or acquired wells as indicated in the table below.

	Year Ended December 31,					
	2011		2010		2009	
	Gross	Net	Gross	Net	Gross	Net
Development Wells						
Productive	**149**	**86.0**	96	74.3	124	103.6
Dry			1	1.0	5	4.0
Extension Wells						
Productive	**7**	**5.5**	12	8.3	7	7.0
Dry						
Exploratory Wells						
Productive	**4**	**3.5**	3	2.5	5	2.5
Dry	**1**	**1.0**	1	1.0	2	1.5
Total	**161**	**96.0**	113	87.1	143	118.6
Wells Acquired					1	1.0

At December 31, 2011, 12 wells (7.6 net) were being drilled or awaiting completion.

OTHER BUSINESS MATTERS

Competition

Competition in our primary producing areas is intense. Price, contract terms and quality of service, including pipeline connection times and distribution efficiencies, affect competition. We believe that in the Appalachia area our extensive acreage position, existing natural gas gathering and pipeline systems in West Virginia and our access to gathering and pipeline infrastructure in Pennsylvania, along with services and equipment that we have secured for the upcoming years and storage fields in West Virginia, enhance our competitive position over other producers who do not have similar systems or

services in place. We also actively compete against other companies with substantially larger financial and other resources.

Major Customer

In 2011, we did not have any one customer account for more than 10% of our total sales. In 2010, one customer accounted for approximately 11% of our total sales. In 2009, two customers accounted for approximately 13% and 11%, respectively, of our total sales. We do not believe that the loss of any of these customers would have a material adverse effect on us because alternative customers are readily available.

Seasonality

Demand for natural gas has historically been seasonal, with peak demand and typically higher prices occurring during the colder winter months.

Regulation of Oil and Natural Gas Exploration and Production

Exploration and production operations are subject to various types of regulation at the federal, state and local levels. This regulation includes requiring permits to drill wells, maintaining bonding requirements to drill or operate wells, and regulating the location of wells, the method of drilling and casing wells, the surface use and restoration of properties on which wells are drilled, and the plugging and abandoning of wells. Our operations are also subject to various conservation laws and regulations. These include the regulation of the size of drilling and spacing units or proration units, the density of wells that may be drilled in a given field and the unitization or pooling of oil and natural gas properties. Some states allow the forced pooling or integration of tracts to facilitate exploration while other states rely on voluntary pooling of lands and leases. In addition, state conservation laws establish maximum rates of production from oil and natural gas wells, generally prohibiting the venting or flaring of natural gas and imposing certain requirements regarding the ratability of production. The effect of these regulations is to limit the amounts of oil and natural gas we can produce from our wells, and to limit the number of wells or the locations where we can drill. Because these statutes, rules and regulations undergo constant review and often are amended, expanded and reinterpreted, we are unable to predict the future cost or impact of regulatory compliance. The regulatory burden on the oil and gas industry increases its cost of doing business and, consequently, affects its profitability. We do not believe, however, we are affected differently by these regulations than others in the industry.

Natural Gas Marketing, Gathering and Transportation

Federal legislation and regulatory controls have historically affected the price of the natural gas we produce and the manner in which our production is transported and marketed. Under the Natural Gas Act of 1938 (NGA), the FERC regulates the interstate sale for resale of natural gas and the transportation of natural gas in interstate commerce, although facilities used in the production or gathering of natural gas in interstate commerce are generally exempted from FERC jurisdiction. Effective January 1, 1993, the Natural Gas Wellhead Decontrol Act deregulated natural gas prices for all "first sales" of natural gas, which definition covers all sales of our own production. In addition, as part of the broad industry restructuring initiatives described below, the FERC has granted to all producers such as us a "blanket certificate of public convenience and necessity" authorizing the sale of gas for resale without further FERC approvals. As a result, all of our produced natural gas may now be sold at market prices, subject to the terms of any private contracts that may be in effect. In addition, under the provisions of the Energy Policy Act of 2005 (2005 Act), the NGA has been amended to prohibit any forms of market manipulation in connection with the purchase or sale of natural gas. Pursuant to the 2005 Act, the FERC established new regulations that are intended to increase natural gas pricing transparency through, among other things, requiring market participants to report their gas

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sales transactions annually to the FERC, and new regulations that require certain non-interstate pipelines to post daily scheduled volume information and design capacity for certain points on their systems. The 2005 Act also significantly increased the penalties for violations of the NGA and the FERC's regulations. In 2010, the FERC issued Penalty Guidelines for the determination of civil penalties in an effort to add greater fairness, consistency and transparency to its enforcement program.

Our natural gas sales prices nevertheless continue to be affected by intrastate and interstate gas transportation regulation, because the prices we receive for our production are affected by the cost of transporting the gas to the consuming market. Through a series of comprehensive rulemakings, beginning with Order No. 436 in 1985 and continuing through Order No. 636 in 1992 and Order No. 637 in 2000, the FERC has adopted regulatory changes that have significantly altered the transportation and marketing of natural gas. These changes were intended by the FERC to foster competition by, among other things, transforming the role of interstate pipeline companies from wholesale marketers of gas to the primary role of gas transporters, and by increasing the transparency of pricing for pipeline services. The FERC has also established regulations governing the relationship of pipelines with their marketing affiliates, which essentially require that designated employees function independently of each other, and that certain information not be shared. The FERC has also implemented standards relating to the use of electronic data exchange by the pipelines to make transportation information available on a timely basis and to enable transactions to occur on a purely electronic basis.

In light of these statutory and regulatory changes, most pipelines have divested their gas sales functions to marketing affiliates, which operate separately from the transporter and in direct competition with all other merchants, and most pipelines have also implemented the large-scale divestiture of their gas gathering facilities to affiliated or non-affiliated companies. Interstate pipelines thus now generally provide unbundled, open and nondiscriminatory transportation and transportation-related services to producers, gas marketing companies, local distribution companies, industrial end users and other customers seeking such services. Sellers and buyers of gas have gained direct access to the particular pipeline services they need, and are better able to conduct business with a larger number of counterparties. We believe these changes generally have improved our access to markets while, at the same time, substantially increasing competition in the natural gas marketplace.

Certain of our pipeline systems and storage fields in West Virginia are regulated for safety compliance by the U.S. Department of Transportation (DOT) and the West Virginia Public Service Commission. In 2002, Congress enacted the Pipeline Safety Improvement Act of 2002 (2002 Act), which contains a number of provisions intended to increase pipeline operating safety. The DOT's final regulations implementing the act became effective February 2004. Among other provisions, the regulations require that pipeline operators implement a pipeline integrity management program that must at a minimum include an inspection of gas transmission and non-rural gathering pipeline facilities in certain locations within ten years, and at least every seven years thereafter. On March 15, 2006, the DOT revised these regulations to define more clearly the categories of gathering facilities subject to DOT regulation, establish new safety rules for certain gathering lines in rural areas, revise the current regulations applicable to safety and inspection of gathering lines in non-rural areas, and adopt new compliance deadlines. The initial baseline assessments under our integrity management program for our pipeline system in West Virginia are 96% complete and are expected to be fully complete by the December 2012 deadline. Clarification from the DOT published in 2009 brought to light the need for further baseline assessments of cased pipeline crossings covered under our integrity management program. Reassessment of our West Virginia pipeline system is scheduled to start in 2013 based on the 7 year reassessment requirement.

In December 2006, Congress enacted the Pipeline Inspection, Protection, Enforcement and Safety Act of 2006 (PIPES Act), which reauthorized the programs adopted under the 2002 Act, proposed enhancements for state programs to reduce excavation damage to pipelines, established increased federal enforcement of one-call excavation programs, and established a new program for review of

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pipeline security plans and critical facility inspections. Pursuant to the PIPES Act, the DOT issued regulations on May 5, 2011 that would, with limited exceptions, subject all low-stress hazardous liquids pipelines, regardless of location or size, to the DOT's pipeline safety regulations.

In December 2011, Congress passed the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011. The act increases the maximum civil penalties for pipeline safety administrative enforcement actions; requires the DOT to study and report on the expansion of integrity management requirements, the sufficiency of existing gathering line regulations to ensure safety, and the use of leak detection systems by hazardous liquid pipelines; requires pipeline operators to verify their records on maximum allowable operating pressure; and imposes new emergency response and incident notification requirements.

On December 3, 2009, the DOT adopted a regulation requiring gas and hazardous liquid pipelines that use supervisory control and data acquisition (SCADA) systems and have at least one controller and control room to develop written control room management procedures by August 1, 2011 and implement the procedures by February 1, 2013. The DOT expedited the program implementation deadline to October 1, 2011 for most of the requirements, except for certain provisions regarding adequate information and alarm management, which have a program implementation deadline of August 1, 2012. Effective January 1, 2011, natural gas and hazardous liquid pipelines became subject to updated reporting requirements with DOT. On August 25, 2011, the DOT issued an Advanced Notice of Proposed Rulemaking in which it explained that the DOT is considering changes to the pipeline safety regulations, including expanding its regulation of gas gathering lines.

We cannot predict what new or different regulations the FERC and other regulatory agencies may adopt, or what effect subsequent regulations may have on our activities. Similarly, it is impossible to predict what proposals, if any, that affect the oil and natural gas industry might actually be enacted by Congress or the various state legislatures and what effect, if any, such proposals might have on us. Similarly, and despite the recent trend toward federal deregulation of the natural gas industry, whether or to what extent that trend will continue, or what the ultimate effect will be on our sales of gas, cannot be predicted.

Federal Regulation of Petroleum

Our sales of oil and natural gas liquids are not regulated and are at market prices. The price received from the sale of these products is affected by the cost of transporting the products to market. Much of that transportation is through interstate common carrier pipelines. Effective January 1, 1995, the FERC implemented regulations generally grandfathering all previously approved interstate transportation rates and establishing an indexing system for those rates by which adjustments are made annually based on the rate of inflation, subject to certain conditions and limitations. These regulations may tend to increase the cost of transporting oil and natural gas liquids by interstate pipeline, although the annual adjustments may result in decreased rates in a given year. Every five years, the FERC must examine the relationship between the annual change in the applicable index and the actual cost changes experienced in the oil pipeline industry. In December 2010, to implement this required five-year re-determination, the FERC established an upward adjustment in the index to track oil pipeline cost changes and determined that the Producer Price Index for Finished Goods plus 2.65 percent should be the oil pricing index for the five-year period beginning July 1, 2011. Another FERC matter that may impact our transportation costs relates to a policy that allows a pipeline structured as a master limited partnership or similar non-corporate entity to include in its rates a tax allowance with respect to income for which there is an "actual or potential income tax liability," to be determined on a case by case basis. Generally speaking, where the holder of a partnership unit interest is required to file a tax return that includes partnership income or loss, such unit-holder is presumed to have an actual or potential income tax liability sufficient to support a tax allowance on that partnership income. We currently do not transport any of our oil or natural gas liquids on a pipeline structured as a master limited partnership.

We are not able to predict with certainty the effect upon us of these periodic reviews by the FERC of the pipeline index, or of the application of the FERC's policy on income tax allowances.

Environmental Regulations

General. Our operations are subject to extensive federal, state and local laws and regulations relating to the generation, storage, handling, emission, transportation and discharge of materials into the environment. Permits are required for the operation of our various facilities. These permits can be revoked, modified or renewed by issuing authorities. Governmental authorities enforce compliance with their regulations through fines, injunctions or both. Government regulations can increase the cost of planning, designing, installing and operating, and can affect the timing of installing and operating, oil and gas facilities. Although we believe that compliance with environmental regulations will not have a material adverse effect on us, risks of substantial costs and liabilities related to environmental compliance issues are part of oil and gas production operations. No assurance can be given that significant costs and liabilities will not be incurred. Also, it is possible that other developments, such as stricter environmental laws and regulations, and claims for damages to property or persons resulting from oil and gas production could result in substantial costs and liabilities to us.

The transition zone and shallow-water areas of the U.S. Gulf Coast are ecologically sensitive. Environmental issues have led to higher drilling costs and a more difficult and lengthy well permitting process. U.S. laws and regulations applicable to our operations include those controlling the discharge of materials into the environment, requiring removal and cleanup of materials that may harm the environment, requiring consistency with applicable coastal zone management plans, or otherwise relating to the protection of the environment.

Solid and Hazardous Waste. We currently own or lease, and have in the past owned or leased, numerous properties that were used for the production of oil and gas for many years. Although operating and disposal practices that were standard in the industry at the time may have been utilized, it is possible that hydrocarbons or other wastes may have been disposed of or released on or under the properties currently owned or leased by us. State and federal laws applicable to oil and gas wastes and properties have become stricter over time. Under these increasingly stringent requirements, we could be required to remove or remediate previously disposed wastes (including wastes disposed or released by prior owners and operators) or clean up property contamination (including groundwater contamination by prior owners or operators) or to perform plugging operations to prevent future contamination.

We generate some hazardous wastes that are already subject to the Federal Resource Conservation and Recovery Act (RCRA) and comparable state statutes. The Environmental Protection Agency (EPA) has limited the disposal options for certain hazardous wastes. It is possible that certain wastes currently exempt from treatment as hazardous wastes may in the future be designated as hazardous wastes under RCRA or other applicable statutes. We could, therefore, be subject to more rigorous and costly disposal requirements in the future than we encounter today.

Superfund. The Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA), also known as the "Superfund" law, and comparable state laws and regulations impose liability, without regard to fault or the legality of the original conduct, on certain persons with respect to the release of hazardous substances into the environment. These persons include the current and past owners and operators of a site where the release occurred and any party that treated or disposed of or arranged for the treatment or disposal of hazardous substances found at a site. Under CERCLA, such persons may be subject to joint and several strict liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources

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and for the costs of certain health studies. CERCLA also authorizes the EPA, and in some cases, private parties, to undertake actions to clean up such hazardous substances, or to recover the costs of such actions from the responsible parties. In addition, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment. In the course of business, we have used materials and generated wastes and will continue to use materials and generate wastes that may fall within CERCLA's definition of hazardous substances. We may also be an owner or operator of sites on which hazardous substances have been released. As a result, we may be responsible under CERCLA for all or part of the costs to clean up sites where such substances have been released.

Oil Pollution Act. The Federal Oil Pollution Act of 1990 (OPA) and resulting regulations impose a variety of obligations on responsible parties related to the prevention of oil spills and liability for damages resulting from such spills in waters of the United States. The term "waters of the United States" has been broadly defined to include inland water bodies, including wetlands and intermittent streams. The OPA assigns joint and several strict liability to each responsible party for oil removal costs and a variety of public and private damages. We believe that we substantially comply with the Oil Pollution Act and related federal regulations.

Clean Water Act. The Federal Water Pollution Control Act (Clean Water Act) and resulting regulations, which are primarily implemented through a system of permits, also govern the discharge of certain contaminants into waters of the United States. Sanctions for failure to comply strictly with the Clean Water Act are generally resolved by payment of fines and correction of any identified deficiencies. However, regulatory agencies could require us to cease construction or operation of certain facilities or to cease hauling wastewaters to facilities owned by others that are the source of water discharges. We believe that we substantially comply with the Clean Water Act and related federal and state regulations.

Clean Air Act. Our operations are subject to the Federal Clean Air Act and comparable local and state laws and regulations to control emissions from sources of air pollution. Federal and state laws require new and modified sources of air pollutants to obtain permits prior to commencing construction. Major sources of air pollutants are subject to more stringent, federally imposed requirements including additional permits. Federal and state laws designed to control toxic air pollutants might require installation of additional controls. Payment of fines and correction of any identified deficiencies generally resolve penalties for failure to comply strictly with air regulations or permits. Regulatory agencies could also require us to cease construction or operation of certain facilities or to install additional controls on certain facilities that are air emission sources. We believe that we substantially comply with the emission standards under local, state, and federal laws and regulations.

Hydraulic Fracturing. Many of our exploration and production operations depend on the use of hydraulic fracturing to enhance production from oil and gas wells. This technology involves the injection of fluids usually consisting mostly of water but typically including small amounts of several chemical additives as well as sand into a well under high pressure in order to create fractures in the rock that allow oil or gas to flow more freely to the wellbore. Most of our wells would not be economical without the use of hydraulic fracturing to stimulate production from the well. Due to concerns raised relating to potential impacts of hydraulic fracturing on groundwater quality, legislative and regulatory efforts at the federal level and in some states have been initiated to render permitting and compliance requirements more stringent for hydraulic fracturing or prohibit the activity altogether. Such efforts could have an adverse effect on oil and natural gas production activities. For additional information about hydraulic fracturing and related environmental matters, please read "Item 1A. Risk Factors Federal and state legislation and regulatory initiatives related to hydraulic fracturing could result in increased costs and operating restrictions or delays."

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Greenhouse Gas. In response to recent studies suggesting that emissions of carbon dioxide and certain other gases may be contributing to global climate change, the U.S. Congress has considered legislation to reduce emissions of greenhouse gases from sources within the United States between 2012 and 2050. In addition, almost one-half of the states have already taken legal measures to reduce emissions of greenhouse gases, primarily through the planned development of greenhouse gas emission inventories and/or regional greenhouse gas cap and trade programs. The EPA has also begun to regulate carbon dioxide and other greenhouse gas emissions under existing provisions of the Clean Air Act. Please read "Item 1A. Risk Factors Climate change and climate change legislation and regulatory initiatives could result in increased operating costs and decreased demand for oil and gas."

Employees

As of December 31, 2011, we had 529 active employees. We recognize that our success is significantly influenced by the relationship we maintain with our employees. Overall, we believe that our relations with our employees are satisfactory. The Company and its employees are not represented by a collective bargaining agreement.

Website Access to Company Reports

We make available free of charge through our website, www.cabotog.com, our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and all amendments to those reports as soon as reasonably practicable after such material is electronically filed with or furnished to the Securities and Exchange Commission (SEC). Information on our website is not a part of this report. In addition, the SEC maintains an Internet site at www.sec.gov that contains reports, proxy and information statements and other information filed by the Company. The public may read and copy materials that we file with the SEC at the SEC's Public Reference Room located at 100 F Street, NE, Washington, DC 20549. Information regarding the operation of the Public Reference Room can be obtained by calling the SEC at 1-800-SEC-0330.

Corporate Governance Matters

The Company's Corporate Governance Guidelines, Corporate Bylaws, Code of Business Conduct, Corporate Governance and Nominations Committee Charter, Compensation Committee Charter and Audit Committee Charter are available on the Company's website at www.cabotog.com, under the "Governance" section of "Investor Info." Requests can also be made in writing to Investor Relations at our corporate headquarters at Three Memorial City Plaza, 840 Gessner Road, Suite 1400, Houston, Texas, 77024.

ITEM 1A. RISK FACTORS

Natural gas and oil prices fluctuate widely, and low prices for an extended period of time are likely to have a material adverse impact on our business.

Our revenues, operating results, financial condition and ability to borrow funds or obtain additional capital depend substantially on prevailing prices for natural gas and, to a lesser extent, oil. Lower commodity prices may reduce the amount of natural gas and oil that we can produce economically. Historically, natural gas and oil prices and markets have been volatile, with prices fluctuating widely, and they are likely to continue to be volatile. Natural gas prices have decreased from an average price of $4.39 per Mmbtu in 2010 to an average price of $4.04 per Mmbtu in 2011. Natural gas prices were $3.36 per Mmbtu in December 2011 and have continued to decline to $2.68 per Mmbtu in February 2012. Natural gas prices represent the first of the month Henry Hub index price per Mmbtu. Oil prices have increased from an average price of $77.32 per barrel in 2010 to an average price of $94.01 per barrel in 2011. Depressed prices in the future would have a negative impact on our

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future financial results. Because our reserves are predominantly natural gas, changes in natural gas prices have a more significant impact on our financial results.

Prices for natural gas and oil are subject to wide fluctuations in response to relatively minor changes in the supply of and demand for natural gas and oil, market uncertainty and a variety of additional factors that are beyond our control. These factors include:

- the level of consumer product demand;
- weather conditions;
- political conditions in natural gas and oil producing regions, including the Middle East;
- the ability of the members of the Organization of Petroleum Exporting Countries to agree to and maintain oil price and production controls;
- the price of foreign imports;
- actions of governmental authorities;
- pipeline availability and capacity constraints;
- inventory storage levels;
- domestic and foreign governmental regulations;
- the price, availability and acceptance of alternative fuels; and
- overall economic conditions.

These factors and the volatile nature of the energy markets make it impossible to predict with any certainty the future prices of natural gas and oil. If natural gas prices decline significantly for a sustained period of time, the lower prices may adversely affect our ability to make planned expenditures, raise additional capital or meet our financial obligations.

Drilling natural gas and oil wells is a high-risk activity.

Our growth is materially dependent upon the success of our drilling program. Drilling for natural gas and oil involves numerous risks, including the risk that no commercially productive natural gas or oil reservoirs will be encountered. The cost of drilling, completing and operating wells is substantial and uncertain, and drilling operations may be curtailed, delayed or cancelled as a result of a variety of factors beyond our control, including:

- unexpected drilling conditions, pressure or irregularities in formations;

- equipment failures or accidents;
- adverse weather conditions;
- compliance with governmental requirements; and
- shortages or delays in the availability of drilling rigs or crews and the delivery of equipment.

Our future drilling activities may not be successful and, if unsuccessful, such failure will have an adverse effect on our future results of operations and financial condition. Our overall drilling success rate or our drilling success rate for activity within a particular geographic area may decline. We may ultimately not be able to lease or drill identified or budgeted prospects within our expected time frame, or at all. We may not be able to lease or drill a particular prospect because, in some cases, we identify a prospect or drilling location before seeking an option or lease rights in the prospect or location.

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Similarly, our drilling schedule may vary from our capital budget. The final determination with respect to the drilling of any scheduled or budgeted wells will be dependent on a number of factors, including:

- the results of exploration efforts and the acquisition, review and analysis of the seismic data;
- the availability of sufficient capital resources to us and the other participants for the drilling of the prospects;
- the approval of the prospects by other participants after additional data has been compiled;
- economic and industry conditions at the time of drilling, including prevailing and anticipated prices for natural gas and oil and the availability of drilling rigs and crews;
- our financial resources and results; and
- the availability of leases and permits on reasonable terms for the prospects.

These projects may not be successfully developed and the wells, if drilled, may not encounter reservoirs of commercially productive natural gas or oil.

Our proved reserves are estimates. Any material inaccuracies in our reserve estimates or underlying assumptions could cause the quantities and net present value of our reserves to be overstated or understated.

Reserve engineering is a subjective process of estimating underground accumulations of natural gas and crude oil that cannot be measured in an exact manner. The process of estimating quantities of proved reserves is complex and inherently imprecise, and the reserve data included in this document are only estimates. The process relies on interpretations of available geologic, geophysical, engineering and production data. The extent, quality and reliability of this technical data can vary. The process also requires certain economic assumptions, some of which are mandated by the SEC, such as natural gas and oil prices. Additional assumptions include drilling and operating expenses, capital expenditures, taxes and availability of funds.

Results of drilling, testing and production subsequent to the date of an estimate may justify revising the original estimate. Accordingly, initial reserve estimates often vary from the quantities of natural gas and crude oil that are ultimately recovered, and such variances may be material. Any significant variance could reduce the estimated quantities and present value of our reserves.

You should not assume that the present value of future net cash flows from our proved reserves is the current market value of our estimated natural gas and oil reserves. In accordance with SEC requirements, we base the estimated discounted future net cash flows from our proved reserves on the 12-month average oil and gas index prices, calculated as the unweighted arithmetic average for the first day of the month price for each month and costs in effect on the date of the estimate, holding the prices and costs constant throughout the life of the properties. Actual future prices and costs may differ materially from those used in the net present value estimate, and future net present value estimates using then current prices and costs may be significantly less than the current estimate. In addition, the 10% discount factor we use when calculating discounted future net cash flows for reporting requirements in compliance with the Financial Accounting Standards Board (FASB) in Accounting Standards Codification 932 may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with us or the natural gas and oil industry in general.

Our future performance depends on our ability to find or acquire additional natural gas and oil reserves that are economically recoverable.

In general, the production rate of natural gas and oil properties declines as reserves are depleted, with the rate of decline depending on reservoir characteristics. Unless we successfully replace the reserves that we produce, our reserves will decline, eventually resulting in a decrease in natural gas and

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oil production and lower revenues and cash flow from operations. Our future natural gas and oil production is, therefore, highly dependent on our level of success in finding or acquiring additional reserves. We may not be able to replace reserves through our exploration, development and exploitation activities or by acquiring properties at acceptable costs. Low natural gas and oil prices may further limit the kinds of reserves that we can develop economically. Lower prices also decrease our cash flow and may cause us to decrease capital expenditures.

Our reserve report estimates that production from our proved developed reserves as of December 31, 2011 will increase at an estimated rate of 6% during 2012 and then decline at estimated rates of 30%, 22% and 16% during 2013, 2014 and 2015, respectively. Future development of proved undeveloped and other reserves currently not classified as proved developed producing will impact these rates of decline. Because of higher initial decline rates from newly developed reserves, we consider this pattern fairly typical.

Exploration, development and exploitation activities involve numerous risks that may result in dry holes, the failure to produce natural gas and oil in commercial quantities and the inability to fully produce discovered reserves.

Acquired properties may not be worth what we pay due to uncertainties in evaluating recoverable reserves and other expected benefits, as well as potential liabilities.

Successful property acquisitions require an assessment of a number of factors beyond our control. These factors include exploration potential, future natural gas and oil prices, operating costs, and potential environmental and other liabilities. These assessments are complex and inherently imprecise. Our review of the properties we acquire may not reveal all existing or potential problems. In addition, our review may not allow us to fully assess the potential deficiencies of the properties. We do not inspect every well, and even when we inspect a well we may not discover structural, subsurface, or environmental problems that may exist or arise. We may not be entitled to contractual indemnification for pre-closing liabilities, including environmental liabilities, and our contractual indemnification may not be effective. Often, we acquire interests in properties on an "as is" basis with limited remedies for breaches of representations and warranties. If an acquired property is not performing as originally estimated, we may have an impairment which could have a material adverse effect on our financial position and results of operations.

The integration of the properties we acquire could be difficult, and may divert management's attention away from our existing operations.

The integration of the properties we acquire could be difficult, and may divert management's attention and financial resources away from our existing operations. These difficulties include:

- the challenge of integrating the acquired properties while carrying on the ongoing operations of our business; and
- the possibility of faulty assumptions underlying our expectations.

The process of integrating our operations could cause an interruption of, or loss of momentum in, the activities of our business. Members of our management may be required to devote considerable amounts of time to this integration process, which will decrease the time they will have to manage our existing business. If management is not able to effectively manage the integration process, or if any significant business activities are interrupted as a result of the integration process, our business could suffer.

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We face a variety of hazards and risks that could cause substantial financial losses.

Our business involves a variety of operating risks, including:

- well site blowouts, cratering and explosions;
- equipment failures;
- pipe or cement failures and casing collapses, which can release natural gas, oil, drilling fluids or hydraulic fracturing fluids;
- uncontrolled flows of natural gas, oil or well fluids;
- fires;
- formations with abnormal pressures;
- handling and disposal of materials, including drilling fluids and hydraulic fracturing fluids;
- pollution and other environmental risks; and
- natural disasters.

Any of these events could result in injury or loss of human life, loss of hydrocarbons, significant damage to or destruction of property, environmental pollution, regulatory investigations and penalties, suspension or impairment of our operations and substantial losses to us.

Our operation of natural gas gathering and pipeline systems also involves various risks, including the risk of explosions and environmental hazards caused by pipeline leaks and ruptures. The location of pipelines near populated areas, including residential areas, commercial business centers and industrial sites, could increase these risks. As of December 31, 2011, we owned or operated approximately 3,105 miles of natural gas gathering and pipeline systems. As part of our normal maintenance program, we have identified certain segments of our pipelines that we believe periodically require repair, replacement or additional maintenance.

We may not be insured against all of the operating risks to which we are exposed.

We maintain insurance against some, but not all, of these risks and losses. We do not carry business interruption insurance. In addition, pollution and environmental risks generally are not fully insurable. The occurrence of an event not fully covered by insurance could have a material adverse effect on our financial position, results of operations and cash flows.

We have limited control over the activities on properties we do not operate.

Other companies operate some of the properties in which we have an interest. Non-operated wells represented approximately 11.0% of our total owned gross wells, or approximately 3.1% of our owned net wells, as of December 31, 2011. We have limited ability to influence or control the operation or future development of these non-operated properties or the amount of capital expenditures that we are required to fund with respect to them. The failure of an operator of our wells to adequately perform operations, an operator's breach of the applicable agreements or an operator's failure to act in ways that are in our best interest could reduce our production and revenues. Our dependence on the operator and other working interest owners for these projects and our limited ability to influence or control the operation and future development of these properties could materially adversely affect the realization of our targeted returns on capital in drilling or acquisition activities and lead to unexpected future costs.

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Terrorist activities and the potential for military and other actions could adversely affect our business.

The threat of terrorism and the impact of military and other action have caused instability in world financial markets and could lead to increased volatility in prices for natural gas and oil, all of which could adversely affect the markets for our operations. Future acts of terrorism could be directed against companies operating in the United States. The U.S. government has issued public warnings that indicate that energy assets might be specific targets of terrorist organizations. These developments have subjected our operations to increased risk and, depending on their ultimate magnitude, could have a material adverse effect on our business.

Our ability to sell our natural gas and oil production could be materially harmed if we fail to obtain adequate services such as transportation and processing.

The sale of our natural gas and oil production depends on a number of factors beyond our control, including the availability and capacity of transportation and processing facilities. We deliver our natural gas and oil production primarily through gathering systems and pipelines that we do not own. The lack of available of capacity on these systems and facilities could reduce the price offered for our production or result in the shut-in of producing wells or the delay or discontinuance of development plans for properties. Third-party systems and facilities may be unavailable due to market conditions or mechanical or other reasons. Our failure to obtain these services on acceptable terms could materially harm our business.

Competition in our industry is intense, and many of our competitors have substantially greater financial and technological resources than we do, which could adversely affect our competitive position.

Competition in the natural gas and oil industry is intense. Major and independent natural gas and oil companies actively bid for desirable natural gas and oil properties, as well as for the equipment and labor required to operate and develop these properties. Our competitive position is affected by price, contract terms and quality of service, including pipeline connection times, distribution efficiencies and reliable delivery record. Many of our competitors have financial and technological resources and exploration and development budgets that are substantially greater than ours. These companies may be able to pay more for exploratory projects and productive natural gas and oil properties and may be able to define, evaluate, bid for and purchase a greater number of properties and prospects than our financial or human resources permit. In addition, these companies may be able to expend greater resources on the existing and changing technologies that we believe are and will be increasingly important to attaining success in the industry.

We may have hedging arrangements that expose us to risk of financial loss and limit the benefit to us of increases in prices for natural gas and oil.

From time to time, when we believe that market conditions are favorable, we use certain derivative financial instruments to manage price risks associated with our production. While there are many different types of derivatives available, we utilized natural gas and crude oil swap agreements and crude oil collar agreements for portions of our 2011 production to attempt to manage price risk more effectively. During 2011, we also entered into crude oil swaps to hedge our price exposure on our 2012 production, natural gas swaps to hedge our price exposure on our 2011 and 2012 production and natural gas collars to hedge our price exposure on our 2013 production. In addition, we also have natural gas basis swaps covering a portion of anticipated 2012 production, which do not qualify for hedge accounting.

The collar arrangements are put and call options used to establish floor and ceiling commodity prices for a fixed volume of production during a certain time period. They provide for payments to counterparties if the index price exceeds the ceiling and payments from the counterparties if the index price falls below the floor. The price swaps call for payments to, or receipts from, counterparties based on whether the market price of natural gas or crude oil for the period is greater or less than the fixed price established for that period when the swap is put in place. These hedging arrangements limit the benefit to us of increases in prices. In addition, these arrangements expose us to risks of financial loss in a variety of circumstances, including when:

- a counterparty is unable to satisfy its obligations;
- production is less than expected; or
- there is an adverse change in the expected differential between the underlying price in the derivative instrument and actual prices received for our production.

We will continue to evaluate the benefit of employing derivatives in the future. Please read "Management's Discussion and Analysis of Financial Condition and Results of Operations" in Item 7 and "Quantitative and Qualitative Disclosures about Market Risk" in Item 7A for further discussion concerning our use of derivatives.

The loss of key personnel could adversely affect our ability to operate.

Our operations are dependent upon a relatively small group of key management and technical personnel, and one or more of these individuals could leave our employment. The unexpected loss of the services of one or more of these individuals could have a detrimental effect on us. In addition, our drilling success and the success of other activities integral to our operations will depend, in part, on our ability to attract and retain experienced geologists, engineers and other professionals. Competition for experienced geologists, engineers and some other professionals is extremely intense. If we cannot retain our technical personnel or attract additional experienced technical personnel, our ability to compete could be harmed.

We are subject to complex laws and regulations, including environmental regulations, which can adversely affect the cost, manner or feasibility of doing business.

Our operations are subject to extensive federal, state and local laws and regulations, including tax laws and regulations and those relating to the generation, storage, handling, emission, transportation and discharge of materials into the environment. These laws and regulations can adversely affect the cost, manner or feasibility of doing business. Many laws and regulations require permits for the operation of various facilities, and these permits are subject to revocation, modification and renewal. Governmental authorities have the power to enforce compliance with their regulations, and violations could subject us to fines, injunctions or both. These laws and regulations have increased the costs of planning, designing, drilling, installing and operating natural gas and oil facilities. In addition, we may be liable for environmental damages caused by previous owners of property we purchase or lease. Risks of substantial costs and liabilities related to environmental compliance issues are inherent in natural gas and oil operations. It is possible that other developments, such as stricter environmental laws and regulations, and claims for damages to property or persons resulting from natural gas and oil production, would result in substantial costs and liabilities.

Federal and state legislation and regulatory initiatives related to hydraulic fracturing could result in increased costs and operating restrictions or delays.

Many of our exploration and production operations depend on the use of hydraulic fracturing to enhance production from oil and gas wells. This technology involves the injection of fluids usually consisting mostly of water but typically including small amounts of several chemical additives as well as sand into a well under high pressure in order to create fractures in the rock that allow oil or gas to flow more freely to the wellbore. Most of our wells would not be economical without the use of

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hydraulic fracturing to stimulate production from the well. Hydraulic fracturing operations have historically been overseen by state regulators as part of their oil and gas regulatory programs; however, the EPA has asserted federal regulatory authority over certain hydraulic fracturing activities involving diesel under the Safe Drinking Water Act and is developing guidance documents related to this newly asserted regulatory authority. As a result, we may be subject to additional permitting requirements for hydraulic fracturing operations as well as various restrictions on those operations. These permitting requirements and restrictions could result in delays in operations at well sites as well as increased costs to make wells productive. Moreover, legislation introduced in Congress would require the public disclosure of certain information regarding the chemical makeup of hydraulic fracturing fluids, and we voluntarily disclose on a well-by-well basis the chemicals we use in the hydraulic fracturing process at www.fracfocus.org.

In addition to these federal legislative proposals, some states in which we operate, such as Pennsylvania, West Virginia, Texas, Kansas, Louisiana and Montana, and certain local governments have adopted, and others are considering adopting, regulations that could restrict hydraulic fracturing in certain circumstances, including requirements regarding chemical disclosure, casing and cementing of wells, withdrawal of water for use in high-volume hydraulic fracturing of horizontal wells, baseline testing of nearby water wells, and restrictions on the type of additives that may be used in hydraulic fracturing operations. For example, the Railroad Commission of Texas adopted rules in December 2011 requiring disclosure of certain information regarding the components used in the hydraulic fracturing process. In addition, both the State of Pennsylvania and certain local governments in that state have adopted a variety of regulations limiting how and where fracturing can be performed. Moreover, in April 2011, the Pennsylvania Department of Environmental Protection (PaDEP) called on all Marcellus Shale natural gas drilling operators to voluntarily cease by May 19, 2011 delivering wastewater to those centralized treatment facilities that were grandfathered from the application of last year's Total Dissolved Solids regulations. Further, on July 22, 2011, the Pennsylvania Governor's Marcellus Shale Advisory Commission released its report setting forth 96 recommendations on a variety of issues related to natural gas development in Pennsylvania. These recommendations are related to infrastructure; public health, safety, and environmental protection; local impact and emergency response; and economic and workforce development. The Commission made the most recommendations in the area of public health, safety and environmental protection, including doubling penalties authorized for violations of the Oil and Gas Act; increasing bonding requirements; authorizing the PaDEP to suspend, revoke or deny permits on a quicker timeframe for violations or failure to correct violations; expanding a well operator's presumed liability for impaired water quality; amending well stimulation and completion reporting requirements to require disclosure of hazardous chemicals used in fracturing; and other issues related to fracturing operations. Some or all of these recommendations will likely be acted upon and may result in the adoption of new laws and regulations governing shale gas development in the Marcellus Shale in Pennsylvania that could result in substantial changes in the way natural gas activities are conducted in the area. If these types of conditions are imposed, we could be subject to increased costs and possibly limits on the productivity of certain wells.

Certain governmental reviews are either underway or being proposed that focus on environmental aspects of hydraulic fracturing practices. The White House Council on Environmental Quality is coordinating an administration-wide review of hydraulic fracturing practices, and a committee of the U.S. House of Representatives has conducted an investigation of hydraulic fracturing practices. Furthermore, a number of federal agencies are analyzing, or have been requested to review, a variety of environmental issues associated with hydraulic fracturing. The EPA has commenced a study of the potential environmental effects of hydraulic fracturing on drinking water and groundwater, with initial results expected to be available by late 2012 and final results by 2014. In addition, the U.S. Department of Energy is conducting an investigation into practices the agency could recommend to better protect the environment from drilling using hydraulic fracturing completion methods. Also, the U.S. Department of the Interior is considering disclosure requirements or other mandates for hydraulic fracturing on federal lands.

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Additionally, certain members of Congress have called upon the U.S. Government Accountability Office to investigate how hydraulic fracturing might adversely affect water resources, the U.S. Securities and Exchange Commission to investigate the natural gas industry and any possible misleading of investors or the public regarding the economic feasibility of pursuing natural gas deposits in shales by means of hydraulic fracturing, and the U.S. Energy Information Administration to provide a better understanding of that agency's estimates regarding natural gas reserves, including reserves from shale formations, as well as uncertainties associated with those estimates. These ongoing or proposed studies, depending on their degree of pursuit and any meaningful results obtained, could spur initiatives to further regulate hydraulic fracturing under the Safe Drinking Water Act or other regulatory mechanisms.

Further, on July 28, 2011, the EPA issued proposed rules that would subject oil and gas production, processing, transmission, storage and distribution operations to regulation under the New Source Performance Standards (NSPS) and National Emission Standards for Hazardous Air Pollutants (NESHAPS) programs. The EPA proposed rules also include NSPS standards for completions of hydraulically fractured gas wells. These standards include the reduced emission completion techniques developed in the EPA's Natural Gas STAR program along with the pit flaring of gas not sent to the gathering line. The standards would be applicable to newly drilled and fractured wells as well as existing wells that are refractured. Further, the proposed regulations under NESHAPS include maximum achievable control technology (MACT) standards for those glycol dehydrators and storage vessels at major sources of hazardous air pollutants not currently subject to MACT standards. We are currently evaluating the effect these proposed rules could have on our business. Final action on the proposed rules is expected by April 2012.

Climate change and climate change legislation and regulatory initiatives could result in increased operating costs and decreased demand for the oil and gas that we produce.

There is increasing attention in the United States and worldwide concerning the issue of climate change and the effect of greenhouse gases. In the United States, climate change action is evolving at the state, regional and federal levels. On December 17, 2010, the EPA amended the "Mandatory Reporting of Greenhouse Gases" final rule ("Reporting Rule") originally issued in September 2009. The Reporting Rule establishes a new comprehensive scheme requiring operators of stationary sources emitting more than established annual thresholds of carbon dioxide-equivalent greenhouse gases to inventory and report their greenhouse gases emissions annually on a facility-by-facility basis. In addition, on December 15, 2009, the EPA published a Final Rule finding that current and projected concentrations of six key greenhouse gases in the atmosphere threaten public health and the welfare of current and future generations. The EPA also found that the combined emissions of these greenhouse gases from new motor vehicles and new motor vehicle engines contribute to pollution that threatens public health and welfare. This Final Rule, also known as the EPA's Endangerment Finding, does not impose any requirements on industry or other entities directly. However, following issuance of the Endangerment Finding, EPA promulgated final motor vehicle GHG emission standards on April 1, 2010, the effect of which could reduce demand for motor fuels refined from crude oil. Also, according to the EPA, the final motor vehicle GHG standards will trigger construction and operating permit requirements for stationary sources. Thus, on June 3, 2010, EPA issued a final rule to address permitting of GHG emissions from stationary sources under the Clean Air Act's Prevention of Significant Deterioration ("PSD") and Title V programs. This final rule "tailors" the PSD and Title V programs to apply to certain stationary sources of GHG emissions in a multi step process, with the largest sources first subject to permitting. In addition, on November 8, 2010, EPA finalized new GHG reporting requirements for upstream petroleum and natural gas systems, which will be added to EPA's GHG Reporting Rule. Facilities containing petroleum and natural gas systems that emit 25,000 metric tons or more of CO_2 equivalent per year will now be required to report annual GHG emissions to EPA, with the first report due on September 28, 2012.

Internationally, in 2005, the Kyoto Protocol to the 1992 United Nations Framework Convention on Climate Change, which establishes a binding set of emission targets for greenhouse gases, became binding on all those countries that had ratified it. International discussions are currently underway to extend the Kyoto Protocol's expiration date of 2012 and to develop a treaty to replace the Kyoto Protocol after its expiration. While it is not possible at this time to predict how regulation that may be enacted to address greenhouse gases emissions would impact our business, the modification of existing laws or regulations or the adoption of new laws or regulations curtailing oil and gas exploration in the areas of the United States in which we operate could materially and adversely affect our operations by limiting drilling opportunities or imposing materially increased costs. In addition, existing or new laws, regulations or treaties (including incentives to conserve energy or use alternative energy sources) could have a negative impact on our business if such incentives reduce demand for oil and gas.

Moreover, some experts believe climate change poses potential physical risks, including an increase in sea level and changes in weather conditions, such as an increase in changes in precipitation and extreme weather events. To the extent that such unfavorable weather conditions are exacerbated by global climate change or otherwise, our operations may be adversely affected to a greater degree than we have previously experienced, including increased delays and costs. However, the uncertain nature of changes in extreme weather events (such as increased frequency, duration, and severity) and the long period of time over which any changes would take place make estimating any future financial risk to our operations caused by these potential physical risks of climate change extremely challenging.

Certain federal income tax law changes have been proposed that, if passed, would have an adverse effect on our financial position, results of operations, and cash flows.

Substantive changes to existing federal income tax laws have been proposed that, if adopted, would repeal many tax incentives and deductions that are currently used by U.S. oil and gas companies and would impose new taxes. The proposals include: elimination of the ability to fully deduct intangible drilling costs in the year incurred; increase in the taxation of foreign source income; repeal of the manufacturing tax deduction for oil and gas companies; and increase in the geological and geophysical amortization period for independent producers. Should some or all of these proposals become law, our taxes will increase, potentially significantly, which would have a negative impact on our net income and cash flows. This could also reduce our drilling activities in the U.S. Since none of these proposals have yet to become law, we do not know the ultimate impact these proposed changes may have on our business.

Provisions of Delaware law and our bylaws and charter could discourage change in control transactions and prevent stockholders from receiving a premium on their investment.

Our bylaws provide for a classified Board of Directors with staggered terms, and our charter authorizes our Board of Directors to set the terms of preferred stock. In addition, Delaware law contains provisions that impose restrictions on business combinations with interested parties. Our bylaws prohibit stockholder action by written consent and limit stockholder proposals at meetings of stockholders. Because of these provisions of our charter, bylaws and Delaware law, persons considering unsolicited tender offers or other unilateral takeover proposals may be more likely to negotiate with our Board of Directors rather than pursue non-negotiated takeover attempts. As a result, these provisions may make it more difficult for our stockholders to benefit from transactions that are opposed by an incumbent Board of Directors.

The personal liability of our directors for monetary damages for breach of their fiduciary duty of care is limited by the Delaware General Corporation Law and by our charter.

The Delaware General Corporation Law allows corporations to limit available relief for the breach of directors' duty of care to equitable remedies such as injunction or rescission. Our charter limits the

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liability of our directors to the fullest extent permitted by Delaware law. Specifically, our directors will not be personally liable for monetary damages for any breach of their fiduciary duty as a director, except for liability:

- for any breach of their duty of loyalty to the company or our stockholders;
- for acts or omissions not in good faith or that involve intentional misconduct or a knowing violation of law;
- under provisions relating to unlawful payments of dividends or unlawful stock repurchases or redemptions; and
- for any transaction from which the director derived an improper personal benefit.

This limitation may have the effect of reducing the likelihood of derivative litigation against directors, and may discourage or deter stockholders or management from bringing a lawsuit against directors for breach of their duty of care, even though such an action, if successful, might otherwise have benefited our stockholders.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 3. LEGAL PROCEEDINGS

Legal Matters

The information set forth under the heading "Legal Matters" in Note 7 of the Notes to Consolidated Financial Statements included in Item 8 of this Annual Report on Form 10-K is incorporated by reference in response to this item.

In August 2011, the Company received a subpoena from the New York Attorney General's Office requesting documents and information regarding the Company's shale and unconventional reservoir reserves calculations. The Company is providing documents and information responsive to the request and is cooperating with the Attorney General's Office in the matter.

Environmental Matters

The information set forth under the heading "Environmental Matters" in Note 7 of the Notes to Consolidated Financial Statements included in Item 8 of this Annual Report on Form 10-K is incorporated by reference in response to this item.

The Company has received a number of Notices of Violation from the Pennsylvania Department of Environmental Protection (PaDEP) relating to alleged violations, primarily with respect to the Pennsylvania Clean Streams Law, the Pennsylvania Oil and Gas Act and the Pennsylvania Solid Waste Management Act and the rules and regulations promulgated thereunder. The Company has responded to these Notices of Violation, has remediated the areas in question and is actively cooperating with the PaDEP. While the Company cannot predict with certainty whether these Notices of Violation will result in fines and/or penalties, if fines and/or penalties are imposed, the aggregate of these fines and/or penalties could result in monetary sanctions in excess of $100,000.

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ITEM 4. MINE SAFETY DISCLOSURE

Not applicable.

EXECUTIVE OFFICERS OF THE REGISTRANT

The following table shows certain information as of February 17, 2012 about our executive officers, as such term is defined in Rule 3b-7 of the Securities Exchange Act of 1934, and certain of our other officers.

Name	Age	Position	Officer Since
Dan O. Dinges	58	Chairman, President and Chief Executive Officer	2001
Scott C. Schroeder	49	Vice President, Chief Financial Officer and Treasurer	1997
G. Kevin Cunningham	58	Vice President, General Counsel	2010
Robert G. Drake	64	Vice President, Information Services and Operational Accounting	1998
Jeffrey W. Hutton	56	Vice President, Marketing	1995
Todd L. Liebl	54	Vice President, Land and Business Development	2012
Steven W. Lindeman	51	Vice President, Engineering and Technology	2011
Lisa A. Machesney	56	Vice President	1995
James M. Reid	60	Vice President, Regional Manager South Region	2009
Phillip L. Stalnaker	52	Vice President, Regional Manager North Region	2009
Todd M. Roemer	41	Controller	2010
Deidre L. Shearer	44	Managing Counsel and Corporate Secretary	2012

All officers are elected annually by our Board of Directors. All of the executive officers have been employed by Cabot Oil & Gas Corporation for at least the last five years, except for Mr. G. Kevin Cunningham, Mr. Todd L. Liebl, Mr. Todd M. Roemer and Ms. Deidre L. Shearer.

Mr. Cunningham joined the Company in November 2009 as Associate General Counsel and was appointed as General Counsel in September 2010 and promoted to Vice President in 2011. Before joining the Company, Mr. Cunningham was Regional Counsel-Southern Division at Chesapeake Energy from 2006 until November 2009. He is a graduate of the University of Texas School of Law and has worked at Fortune 500 E&P companies in both legal and business positions since 1982.

Mr. Liebl joined the Company in September 2008 as South Region Land Manager, promoted to Director of Land in June 2010, Director of Land and Business Development in February 2011 and Vice President in February 2012. Previously, Mr. Liebl held positions with Anadarko Petroleum and most recently Chesapeake Energy from April 2007 until he joined the Company. He holds a Bachelor of Business Administration degree in Petroleum Land Management from the University of Oklahoma.

Mr. Roemer joined the Company in February 2010 after a 14 year career in PricewaterhouseCoopers' energy practice. He is a graduate of the University of Houston Clear Lake with a Bachelor of Science degree in Accounting. Mr. Roemer is a Certified Public Accountant.

Ms. Shearer joined the Company in December 2011 and was appointed Managing Counsel and Corporate Secretary in February 2012. Prior to joining the Company, Ms. Shearer was Assistant General Counsel of KBR, Inc., from January 2007, where she was responsible for corporate governance and SEC and NYSE compliance matters. Ms. Shearer received her J.D. degree from The University of Texas School of Law in 1992 and was primarily in private practice until she joined KBR.

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PART II

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

Our common stock is listed and principally traded on the New York Stock Exchange under the ticker symbol "COG." The following table presents the high and low closing sales prices per share of our common stock during certain periods, as reported in the consolidated transaction reporting system. Cash dividends paid per share of the common stock are also shown. A regular dividend has been declared each quarter since we became a public company in 1990.

On January 3, 2012, the Board of Directors declared a 2-for-1 split of our common stock in the form of a stock dividend. The stock dividend was distributed on January 25, 2012 to shareholders of record on January 17, 2012. All common stock accounts and per share data, including cash dividends per share, have been retroactively adjusted to give effect to the 2-for-1 split of our common stock.

	High	Low	Dividends
2011			
First Quarter	**$ 26.70**	**$ 18.72**	**$ 0.015**
Second Quarter	**$ 33.16**	**$ 25.47**	**$ 0.015**
Third Quarter	**$ 38.56**	**$ 29.65**	**$ 0.015**
Fourth Quarter	**$ 44.30**	**$ 29.29**	**$ 0.015**
2010			
First Quarter	$ 23.12	$ 18.20	$ 0.015
Second Quarter	$ 20.26	$ 15.17	$ 0.015
Third Quarter	$ 16.81	$ 13.50	$ 0.015
Fourth Quarter	$ 18.93	$ 14.14	$ 0.015

As of February 1, 2012, there were 470 registered holders of the common stock.

ISSUER PURCHASES OF EQUITY SECURITIES

Our Board of Directors has authorized a share repurchase program under which we may purchase shares of common stock in the open market or in negotiated transactions. There is no expiration date associated with the authorization. During 2011, we did not repurchase any shares of common stock. All purchases executed to date have been through open market transactions. The maximum number of remaining shares that may be purchased under the plan as of December 31, 2011 was 9,590,600, after giving effect to the 2-for-1 stock split effected in January 2012.

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PERFORMANCE GRAPH

The following graph compares our common stock performance ("COG") with the performance of the Standard & Poors' 500 Stock Index and the Dow Jones US Exploration & Production Index for the period December 2006 through December 2011. The graph assumes that the value of the investment in our common stock and in each index was $100 on December 31, 2006 and that all dividends were reinvested.

Calculated Values*	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**
S&P 500	$ 100.00	$ 105.49	$ 66.46	$ 84.05	$ 96.71	$ 98.75
COG	$ 100.00	$ 133.54	$ 86.27	$ 145.14	$ 126.48	$ 254.16
Dow Jones US Exploration & Production	$ 100.00	$ 143.67	$ 86.02	$ 120.92	$ 141.16	$ 135.25

* *Year-end closing values.*

The performance graph above is furnished and not filed for purposes of Section 18 of the Securities Exchange Act of 1934 and will not be incorporated by reference into any registration statement filed under the Securities Act of 1933 unless specifically identified therein as being incorporated therein by reference. The performance graph is not soliciting material subject to Regulation 14A.

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ITEM 6. SELECTED FINANCIAL DATA

The following table summarizes our selected consolidated financial data for the periods indicated. This information should be read in conjunction with Management's Discussion and Analysis of Financial Condition and Results of Operations in Item 7, and the Consolidated Financial Statements and related Notes in Item 8.

	Year Ended December 31,				
(In thousands, except per share amounts)	**2011**	**2010**	**2009**	**2008**	**2007**
Statement of Operations Data					
Operating Revenues	**$ 979,864**	$ 863,104	$ 893,085	$ 956,746	$ 741,130
Impairment of Oil and Gas Properties and Other Assets		40,903	17,622	35,700	4,614
Gain / (Loss) on Sale of Assets[1]	**63,382**	106,294	(3,303)	1,143	13,448
Gain on Settlement of Dispute[2]				51,906	
Income from Operations	**306,850**	266,439	282,269	372,012	274,693
Net Income	**122,408**	103,386	148,343	211,290	167,423
Basic Earnings per Share[3]	**$ 0.59**	$ 0.50	$ 0.72	$ 1.05	$ 0.87
Diluted Earnings per Share[3]	**$ 0.58**	$ 0.49	$ 0.71	$ 1.04	$ 0.86
Dividends per Common Share[3]	**$ 0.06**	$ 0.06	$ 0.06	$ 0.06	$ 0.06
Balance Sheet Data					
Properties and Equipment, Net	**$ 3,934,584**	$ 3,762,760	$ 3,358,199	$ 3,135,828	$ 1,908,117
Total Assets	**4,331,493**	4,005,031	3,683,401	3,701,664	2,208,594
Current Portion of Long-Term Debt				35,857	20,000
Long-Term Debt	**950,000**	975,000	805,000	831,143	330,000
Stockholders' Equity	**2,104,768**	1,872,700	1,812,514	1,790,562	1,070,257

(1) *Gain on Sale of Assets in 2011 includes $34.2 million gain from the sale of certain Haynesville and Bossier Shale oil and gas properties and an aggregate gain of $29.2 million from the sale of various other properties during the year. Gain on Sale of Assets in 2010 includes $40.7 million from the sale of the Company's investment in Tourmaline, $49.3 million from the sale of our Pennsylvania gathering infrastructure and an aggregate gain of $16.3 million from the sale of various other properties during the year. Gain on Sale of Assets for 2007 includes $12.3 million related to the disposition of our remaining offshore portfolio and certain south Louisiana properties.*

(2) *Gain on Settlement of Dispute is associated with the Company's settlement of a dispute in the fourth quarter of 2008. The dispute settlement includes the value of cash and properties received.*

(3) *All Earnings per Share and Dividends per Common Share figures have been retroactively adjusted for the 2-for-1 split of our common stock effective January 25, 2012.*

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

The following discussion is intended to assist you in understanding our results of operations and our present financial condition. Our Consolidated Financial Statements and the accompanying Notes to the Consolidated Financial Statements included elsewhere in this Form 10-K contain additional information that should be referred to when reviewing this material.

As a result of our production growth and the commencement of various transportation and gathering agreements in 2011, we began separately reporting our transportation and gathering costs as a component of operating expenses in the Consolidated Statement of Operations. Previously reported transportation and gathering costs were reflected as a component of Natural Gas Revenues and have been reclassified to conform to current year presentation. Accordingly, previously reported operating revenues and operating expenses have increased with no impact on previously reported net income.

On January 3, 2012, the Board of Directors declared a 2-for-1 split of our common stock in the form of a stock dividend. The stock dividend was distributed on January 25, 2012 to shareholders of record as of January 17, 2012. All common stock accounts and per share data have been retroactively adjusted to give effect to the 2-for-1 split of our common stock.

Statements in this discussion may be forward-looking. These forward-looking statements involve risks and uncertainties, including those discussed below, which could cause actual results to differ from those expressed. Please read "Forward-Looking Information" for further details.

OVERVIEW

Cabot Oil & Gas Corporation is a leading independent oil and gas company engaged in the development, exploitation, exploration, production and marketing of natural gas, crude oil and, to a lesser extent, natural gas liquids from its properties in the continental United States. We also transport, store, gather and produce natural gas for resale. Our exploitation and exploration activities are concentrated in areas with known hydrocarbon resources, which are conducive to multi-well, repeatable drilling programs. Our program is designed to be disciplined and balanced, with a focus on achieving strong financial returns.

We evaluate three types of investment alternatives that compete for available capital: drilling opportunities, financial opportunities such as debt repayment or repurchase of common stock, and acquisition opportunities. Depending on circumstances, we allocate capital among the alternatives based on a rate-of-return approach. Our goal is to invest capital in the highest return opportunities available at any given time that meet our strategic objectives. At any one time, one or more of these may not be economically feasible.

Our financial results depend upon many factors, particularly the price of natural gas and crude oil and our ability to market our production on economically attractive terms. Price volatility in the commodity markets has remained prevalent in the last few years. Our realized natural gas and crude oil price was $4.46 per Mcf and $90.49 per Bbl, respectively, in 2011. In an effort to manage commodity price risk, we opportunistically enter into natural gas and crude oil price swaps and collars. These financial instruments are a component of our risk management strategy.

Commodity prices are impacted by many factors that are outside of our control. Historically, commodity prices have been volatile and we expect them to remain volatile. Commodity prices are affected by changes in market supply and demand, which are impacted by overall economic activity, weather, pipeline capacity constraints, inventory storage levels, basis differentials and other factors. As a result, we cannot accurately predict future natural gas, NGL and crude oil prices and, therefore, we cannot determine with any degree of certainty what effect increases or decreases will have on our capital program, production volumes and future revenues. In addition to production volumes and commodity prices, finding and developing sufficient amounts of crude oil and natural gas reserves at economical costs are critical to our long-term success. See "Risk Factors Natural gas and oil prices fluctuate widely, and low prices for an extended period of time are likely to have a material adverse impact on our business" and "Risk Factors Our future performance depends on our ability to find or acquire additional natural gas and oil reserves that are economically recoverable" in Item 1A.

The table below illustrates how natural gas prices have fluctuated by month over 2010 and 2011. "Index" represents the first of the month Henry Hub index price per Mmbtu. The "2010" and "2011" price is the natural gas price per Mcf realized by us and includes the realized impact of our natural gas derivative instruments, as applicable:

Natural Gas Prices by Month 2011

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Index	**$ 4.22**	**$ 4.32**	**$ 3.79**	**$ 4.24**	**$ 4.38**	**$ 4.33**	**$ 4.36**	**$ 4.38**	**$ 3.85**	**$ 3.76**	**$ 3.51**	**$ 3.36**
2011	**$ 4.64**	**$ 4.97**	**$ 4.46**	**$ 4.76**	**$ 4.72**	**$ 4.55**	**$ 4.71**	**$ 4.70**	**$ 4.33**	**$ 4.14**	**$ 3.89**	**$ 4.03**

Natural Gas Prices by Month 2010

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Index	$ 5.82	$ 5.28	$ 4.81	$ 3.84	$ 4.27	$ 4.16	$ 4.73	$ 4.78	$ 3.64	$ 3.84	$ 3.29	$ 4.27
2010	$ 7.10	$ 6.61	$ 6.43	$ 5.52	$ 5.66	$ 5.76	$ 5.81	$ 5.76	$ 5.00	$ 5.13	$ 4.80	$ 5.57

The table below illustrates how crude oil prices have fluctuated by month over 2010 and 2011. "Index" represents the NYMEX monthly average crude oil price. The "2010" and "2011" price is the crude oil price per Bbl realized by us and includes the realized impact of our crude oil derivative instruments:

Crude Oil Prices by Month 2011

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Index	**$ 88.81**	**$ 88.86**	**$ 93.57**	**$ 104.00**	**$ 108.15**	**$ 99.49**	**$ 93.40**	**$ 98.14**	**$ 84.12**	**$ 86.89**	**$ 85.30**	**$ 97.41**
2011	**$ 84.65**	**$ 85.19**	**$ 92.37**	**$ 96.16**	**$ 95.44**	**$ 93.82**	**$ 92.99**	**$ 85.17**	**$ 83.59**	**$ 86.99**	**$ 93.97**	**$ 94.46**

Crude Oil Prices by Month 2010

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Index	$ 72.47	$ 77.62	$ 80.16	$ 81.25	$ 83.45	$ 68.01	$ 77.21	$ 77.44	$ 73.46	$ 73.52	$ 81.77	$ 81.51
2010	$ 101.75	$ 96.32	$ 95.25	$ 97.07	$ 94.48	$ 98.82	$ 99.00	$ 101.47	$ 94.95	$ 101.01	$ 97.51	$ 100.24

Natural gas revenues increased from 2010 to 2011 as a result of increased natural gas production, partially offset by decreased commodity prices. Crude oil revenues increased from 2010 to 2011 primarily due to increased crude oil production partially offset by decreased realized prices. Prices, including the realized impact of derivative instruments, decreased by 22% for natural gas and 8% for crude oil.

We drilled 161 gross wells with a success rate of over 99% in 2011 compared to 113 gross wells with a success rate of 98% in 2010. Total capital and exploration expenditures increased by $14.0 million to $905.5 million in 2011 compared to $891.5 million in 2010. The increase in spending was substantially driven by an expanded Marcellus shale horizontal drilling program and increases in our drilling programs in the Eagle Ford oil shale in south Texas and the Marmaton oil play in Oklahoma. We believe our cash on hand and operating cash flow in 2012 will be sufficient to fund our budgeted capital and exploration spending between $750 and $790 million. Any additional needs are expected to be funded by borrowings from our credit facility.

Our 2012 strategy will remain consistent with 2011. While we consider acquisitions from time to time, we remain focused on pursuing drilling opportunities that provide more predictable results on our

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accumulated acreage position. Additionally, we intend to maintain spending discipline and manage our balance sheet in an effort to ensure sufficient liquidity, including cash resources and available credit. For 2012, we have allocated our planned program for capital and exploration expenditures primarily to the Marcellus shale in northeast Pennsylvania, the Eagle Ford oil shale in south Texas and, to a lesser extent, the Marmaton oil play in Oklahoma. We believe these strategies are appropriate for our portfolio of projects and the current commodity pricing environment and will continue to add shareholder value over the long-term.

The preceding paragraphs, discussing our strategic pursuits and goals, contain forward-looking information. Please read "Forward-Looking Information" for further details.

FINANCIAL CONDITION

Capital Resources and Liquidity

Our primary sources of cash in 2011 were from funds generated from the sale of natural gas and crude oil production (including hedge realizations), borrowings under our credit facility and the sales of properties and other assets during the year. These cash flows were primarily used to fund our capital and exploration expenditures, in addition to repayments of debt and related interest, contributions to our pension plans and dividends. See below for additional discussion and analysis of cash flow.

We generate cash from the sale of natural gas and crude oil. Operating cash flow fluctuations are substantially driven by commodity prices and changes in our production volumes. Prices for crude oil and natural gas have historically been volatile, including seasonal influences characterized by peak demand and higher prices in the winter heating season; however, the impact of other risks and uncertainties have also influenced prices throughout the recent years. In addition, fluctuations in cash flow may result in an increase or decrease in our capital and exploration expenditures. See "Results of Operations" for a review of the impact of prices and volumes on revenues.

Our working capital is also substantially influenced by variables discussed above. From time to time, our working capital will reflect a surplus, while at other times it will reflect a deficit. This fluctuation is not unusual. We believe we have adequate availability under our credit facility and liquidity available to meet our working capital requirements.

	Year Ended December 31,		
(In thousands)	**2011**	**2010**	**2009**
Cash Flows Provided by Operating Activities	**$ 501,839**	$ 484,911	$ 614,052
Cash Flows Used in Investing Activities	**(487,620)**	(613,741)	(531,027)
Cash Flows Provided by / (Used in) Financing Activities	**(40,257)**	144,621	(70,968)
Net Increase / (Decrease) in Cash and Cash Equivalents	**$ (26,038)**	$ 15,791	$ 12,057

Operating Activities

Key components impacting net operating cash flows are commodity prices, production volumes and operating expenses. Net cash provided by operating activities in 2011 increased by $16.9 million over 2010. This increase was primarily due to increased operating income in 2011 as a result of higher operating revenues that outpaced the increase in operating expenses. This increase was offset by changes in working capital which decreased operating cash flows. The increase in operating revenues was primarily due to an increase in equivalent production partially offset by lower realized natural gas and crude oil prices. Equivalent production volumes increased by 44% for 2011 compared to 2010 as a result of higher natural gas and crude oil production. Average realized natural gas prices decreased by

22% for 2011 compared to 2010. Average realized crude oil prices decreased by 8% compared to the same period.

Net cash provided by operating activities in 2010 decreased by $129.1 million over 2009. This decrease was mainly due to a decrease in oil and gas revenues and higher operating and interest expense. Average realized natural gas prices decreased by 25% in 2010 compared to 2009 and average realized crude oil prices increased by 14% over the same period. Equivalent production volumes increased by 27% in 2010 compared to 2009 primarily due to higher natural gas and crude oil production.

See "Results of Operations" for additional information relative to commodity price, production and operating expense movements. We are unable to predict future commodity prices and, as a result, cannot provide any assurance about future levels of net cash provided by operating activities. Realized prices may decline in future periods.

Investing Activities

The primary use of cash in investing activities was capital and exploration expenditures. We established the budget for these amounts based on our current estimate of future commodity prices and cash flows. Due to the volatility of commodity prices and new opportunities which may arise, our capital expenditures may be periodically adjusted during any given year. Cash flows used in investing activities decreased by $126.1 million from 2010 to 2011 and increased by $82.7 million from 2009 to 2010. The decrease from 2010 to 2011 was due to an increase of $160.1 million of proceeds from the sale of assets partially offset by an increase of $34.0 million in capital and exploration expenditures.

The increase from 2009 to 2010 was due to an increase of $246.0 million in capital and exploration expenditures partially offset by an increase of $163.3 million of proceeds from the sale of assets.

Financing Activities

Cash flows used in financing activities increased by $184.9 million from 2010 to 2011. This was primarily due to a decrease in borrowings of $195.0 million, partially offset by a decrease in cash paid for capitalized debt issuance costs of $12.8 million.

At December 31, 2011, we had $188.0 million of borrowings outstanding under our unsecured credit facility at a weighted-average interest rate of 4.9% and $711.0 million available for future borrowing.

Cash flows provided by financing activities increased by $215.6 million from 2009 to 2010. This was primarily due to an increase in borrowings of $420.0 million, partially offset by an increase in repayments of debt of $188.0 million, an increase in cash paid for capitalized debt issuance costs by a total of $3.4 million and a decrease of $13.7 million in the tax benefit associated with stock-based compensation.

In December 2010, we completed a private placement of $175.0 million aggregate principal amount of senior unsecured fixed-rate notes with a weighted-average interest rate of 5.58%, consisting of amounts due in January 2021, 2023 and 2026.

In September 2010, we amended and restated our revolving credit facility (credit facility) to increase the available credit line to $900 million with an accordion feature allowing us to increase the available credit line to $1.0 billion, if any one or more of the existing banks or new banks agree to provide such increased commitment amount, and to extend the term to September 2015. The available credit line is subject to adjustment on the basis of the present value of estimated future net cash flows from proved oil and gas reserves (as determined by the banks based on our reserve reports and engineering reports) and certain other assets and the outstanding principal balance of our senior notes.

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The amended facility provided for an initial $1.5 billion borrowing base. Effective April 1, 2011, the lenders under our revolving credit facility approved an increase in our borrowing base from $1.5 billion to $1.7 billion as part of the annual redetermination under the terms of the credit facility. Our plan to sell certain oil and gas properties located in Colorado, Utah and Wyoming triggered an interim redetermination of our borrowing base and the $1.7 billion borrowing base was reaffirmed by the lenders effective September 27, 2011.

In June 2010, we amended the agreements governing our senior notes to amend the required asset coverage ratio (the present value of our proved reserves plus working capital to debt) contained in the agreements. The amendment also changed the ratio for maximum calculated indebtedness to borrowing base (as defined in the credit facility agreement).

We strive to manage our debt at a level below the available credit line in order to maintain borrowing capacity. Our credit facility includes a covenant limiting our total debt. Management believes that, with internally generated cash, existing cash on hand and availability under our credit facility, we have the capacity to finance our spending plans and maintain our strong financial position.

Capitalization

Information about our capitalization is as follows:

	December 31,	
(Dollars in thousands)	**2011**	**2010**
Debt[1]	**$ 950,000**	$ 975,000
Stockholders' Equity	**$ 2,104,768**	$ 1,872,700
Total Capitalization	**$ 3,054,768**	$ 2,847,700
Debt to Capitalization	**31%**	34%
Cash and Cash Equivalents	**$ 29,911**	$ 55,949

(1) *Includes $188.0 million and $213.0 million of borrowings outstanding under our revolving credit facility at December 31, 2011 and 2010, respectively.*

For the year ended December 31, 2011, we paid dividends of $12.5 million ($0.06 per share) on our common stock. A regular dividend has been declared for each quarter since we became a public company in 1990.

Capital and Exploration Expenditures

On an annual basis, we generally fund most of our capital and exploration activities, excluding any significant oil and gas property acquisitions, with cash generated from operations and, when necessary, borrowings under our credit facility. We budget these capital expenditures based on our projected cash flows for the year.

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The following table presents major components of our capital and exploration expenditures:

(In thousands)	Year Ended December 31, 2011	2010	2009
Capital Expenditures			
Drilling and Facilities	**$ 780,673**	$ 654,153	$ 401,143
Leasehold Acquisitions	**71,134**	130,675	145,681
Acquisitions		801	394
Pipeline and Gathering	**7,378**	54,811	32,861
Other	**9,840**	8,368	9,506
	869,025	848,808	589,585
Exploration Expense	**36,447**	42,725	50,784
Total	**$ 905,472**	$ 891,533	$ 640,369

We plan to drill approximately 120 to 130 gross wells in 2012 compared with 161 gross wells drilled in 2011. This 2012 drilling program includes between $750 and $790 million in total capital and exploration expenditures, down from $905.5 million in 2011. This decrease is primarily due to decreased drilling activity as a result of lower commodity prices. We will continue to assess the natural gas and crude oil price environment and our liquidity position and may increase or decrease our capital and exploration expenditures accordingly.

Contractual Obligations

Our material contractual obligations include long-term debt, interest on long-term debt, gas transportation agreements, drilling rig commitments, hydraulic fracturing services commitments and operating leases. We have no off-balance sheet debt or other similar unrecorded obligations.

A summary of our contractual obligations as of December 31, 2011 are set forth in the following table:

		Payments Due by Year			
(In thousands)	Total	2012	2013 to 2014	2015 to 2016	2017 & Beyond
Long-Term Debt	**$ 950,000**	$	$ 75,000	$ 208,000	$ 667,000
Interest on Long-Term Debt(1)	**392,802**	60,163	109,285	89,464	133,890
Gas Transportation Agreements(2)	**1,853,329**	84,285	237,327	244,726	1,286,991
Drilling Rig Commitments(2)	**45,881**	19,766	26,115		
Hydraulic Fracturing Services Commitments(2)	**82,207**	82,207			
Operating Leases(2)	**18,635**	5,656	9,902	3,077	
Total Contractual Obligations	**$ 3,342,854**	$ 252,077	$ 457,629	$ 545,267	$ 2,087,881

(1) *Interest payments have been calculated utilizing the fixed rates of our $762.0 million long-term debt outstanding at December 31, 2011. Interest payments on our revolving credit facility were calculated by assuming that the December 31, 2011 outstanding balance of $188.0 million will be outstanding through the September 2015 maturity date. A constant interest rate of 4.9% was assumed, which was the December 31, 2011 weighted-average interest rate. Actual results will differ from these estimates and assumptions.*

(2) *For further information on our obligations under gas transportation agreements, drilling rig commitments, hydraulic fracturing services commitments and operating leases, see Note 7 of the Notes to the Consolidated Financial Statements.*

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Amounts related to our asset retirement obligations are not included in the above table given the uncertainty regarding the actual timing of such expenditures. The total amount of asset retirement obligations at December 31, 2011 was $60.1 million, down from $72.3 million at December 31, 2010. This decrease is primarily due to $12.1 million of liabilities divested, $3.6 million in downward revisions of previous estimates and $1.2 million in liabilities settled, partially offset by $3.3 million in accretion expense during 2011 and $1.5 million of liabilities incurred. See Note 8 of the Notes to the Consolidated Financial Statements for further details.

Potential Impact of Our Critical Accounting Policies

Readers of this document and users of the information contained in it should be aware of how certain events may impact our financial results based on the accounting policies in place. Our most significant policies are discussed below.

Successful Efforts Method of Accounting

We follow the successful efforts method of accounting for our oil and gas producing activities. Acquisition costs for proved and unproved properties are capitalized when incurred. Exploration costs, including geological and geophysical costs, the costs of carrying and retaining unproved properties and exploratory dry hole costs are expensed. Development costs, including costs to drill and equip development wells and successful exploratory drilling costs to locate proved reserves are capitalized.

Oil and Gas Reserves

The process of estimating quantities of proved reserves is inherently imprecise, and the reserve data included in this document are only estimates. The process relies on interpretations of available geologic, geophysical, engineering and production data. The extent, quality and reliability of this technical data can vary. The process also requires certain economic assumptions, some of which are mandated by the SEC, such as oil and gas prices. Additional assumptions include drilling and operating expenses, capital expenditures, taxes and availability of funds. Any significant variance in the interpretations or assumptions could materially affect the estimated quantity and value of our reserves.

Our reserves have been prepared by our petroleum engineering staff and audited by Miller & Lents, Ltd., independent petroleum engineers, who in their opinion determined the estimates presented to be reasonable in the aggregate. For more information regarding reserve estimation, including historical reserve revisions, refer to the Supplemental Oil and Gas Information to the Consolidated Financial Statements included in Item 8.

Our rate of recording DD&A expense is dependent upon our estimate of proved and proved developed reserves, which are utilized in our unit-of-production method calculation. If the estimates of proved reserves were to be reduced, the rate at which we record DD&A expense would increase, reducing net income. Such a reduction in reserves may result from lower market prices, which may make it uneconomic to drill for and produce higher cost fields. A five percent positive or negative revision to proved reserves throughout the Company would decrease or increase the DD&A rate by approximately ($0.05) to $0.06 per Mcfe. Revisions in significant fields may individually affect our DD&A rate. It is estimated that a positive or negative reserve revision of 10% in one of our most productive fields would have a ($0.05) to $0.06 per Mcfe impact on our total DD&A rate. These estimated impacts are based on current data, and actual events could require different adjustments to our DD&A rate.

In addition, a decline in proved reserve estimates may impact the outcome of our impairment test under Accounting Standards Codification (ASC) 360, "Property, Plant, and Equipment." Due to the inherent imprecision of the reserve estimation process, risks associated with the operations of proved

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producing properties and market sensitive commodity prices utilized in our impairment analysis, management cannot determine if an impairment is reasonably likely to occur in the future.

Carrying Value of Oil and Gas Properties

We evaluate our oil and gas properties for impairment on a field-by-field basis whenever events or changes in circumstances indicate an asset's carrying amount may not be recoverable. We compare expected undiscounted future cash flows to the net book value of the asset. If the future undiscounted expected cash flows, based on our estimate of future crude oil and natural gas prices, operating costs and anticipated production from proved reserves are lower than the net book value of the asset, the capitalized cost is reduced to fair value. Commodity pricing is estimated by using a combination of assumptions management uses in its budgeting and forecasting process as well as historical and current prices adjusted for geographical location and quality differentials, as well as other factors that management believes will impact realizable prices. In the event that commodity prices remain low or continue to decline, there could be a significant revision in the future. Fair value is calculated by discounting the future cash flows. The discount factor used is based on rates utilized by market participants that are commensurate with the risks inherent in the development and production of the underlying natural gas and crude oil.

Costs attributable to our unproved properties are not subject to the impairment analysis described above; however, a portion of the costs associated with such properties is subject to amortization based on past drilling and exploration experience and average property lives. Average property lives are determined on a geographical basis and based on the estimated life of unproved property leasehold rights. Historically, the average property life in each of the geographical areas has not significantly changed and generally range from three to five years. The commodity price environment may impact the capital available for exploration projects as well as development drilling. We have considered these impacts when determining the amortization rate of our undeveloped acreage, especially in exploratory areas. If the average unproved property life decreases or increases by one year, the amortization would increase by approximately $23.8 million or decrease by approximately $15.6 million, respectively, per year.

As these properties are developed and reserves are proven, the remaining capitalized costs are subject to depreciation and depletion. If the development of these properties is deemed unsuccessful, the capitalized costs related to the unsuccessful activity is expensed in the year the determination is made. The rate at which the unproved properties are written off depends on the timing and success of our future exploration and development program.

Natural gas prices have decreased from an average price of $4.39 per Mmbtu in 2010 to an average price of $4.04 per Mmbtu in 2011. Natural gas prices were $3.36 per Mmbtu in December 2011 and have continued to decline to $2.68 per Mmbtu in February 2012. Natural gas prices represent the first of the month Henry Hub index price per Mmbtu. Oil prices have increased from an average price of $77.32 per barrel in 2010 to an average price of $94.01 per barrel in 2011. Any further decline in natural gas prices or quantities could result in an impairment of proved oil and gas properties.

Asset Retirement Obligation

The majority of our asset retirement obligation (ARO) relates to the plugging and abandonment of oil and gas wells and to a lesser extent meter stations, pipelines, processing plants and compressors. We record the fair value of a liability for an asset retirement obligation in the period in which it is incurred, with the associated asset retirement cost capitalized as part of the carrying amount of the related long-lived asset. The recognition of an asset retirement obligation requires management to make assumptions that include estimated plugging and abandonment costs, timing of settlements, inflation rates and discount rate. In periods subsequent to initial measurement, the asset retirement cost is allocated to expense using a systematic and rational method over the assets' useful life, while increases in the discounted ARO liability resulting from the passage of time (accretion expense) are reflected as depreciation, depletion and amortization expense.

Accounting for Derivative Instruments and Hedging Activities

We follow the accounting prescribed in ASC 815. Under ASC 815, the fair value of each derivative instrument is recorded as either an asset or liability on the balance sheet. At the end of each quarterly period, these instruments are marked-to-market. The gain or loss on the change in fair value is recorded as Accumulated Other Comprehensive Income, a component of equity, to the extent that the derivative instrument is designated as a hedge and is effective. The ineffective portion, if any, of the change in the fair value of derivatives designated as hedges and the change in fair value of derivatives not qualifying as hedges are recorded currently in earnings as a component of Natural Gas and Crude Oil and Condensate revenue in the Consolidated Statement of Operations.

The fair value of our derivative instruments are measured based on quotes from the Company's counterparties. Such quotes have been derived using valuation models that consider various inputs including current market and contractual prices for the underlying instruments, quoted forward prices for natural gas and crude oil, volatility factors and interest rates, such as a LIBOR curve for a similar length of time as the derivative contract term as applicable. These estimates are verified using relevant NYMEX futures contracts or are compared to multiple quotes obtained from counterparties for reasonableness. The Company measured the nonperformance risk of its counterparties by reviewing credit default swap spreads for the various financial institutions in which it has derivative transactions. In times where we have net derivative contract liabilities, our nonperformance risk is evaluated using a market credit spread provided by our bank.

Employee Benefit Plans

Our costs of long-term employee benefits, particularly pension and postretirement benefits, are incurred over long periods of time, and involve many uncertainties over those periods. The net periodic benefit cost attributable to current periods is based on several assumptions about such future uncertainties, and is sensitive to changes in those assumptions. It is management's responsibility, often with the assistance of independent experts, to select assumptions that in its judgment represent best estimates of those uncertainties. It also is management's responsibility to review those assumptions periodically to reflect changes in economic or other factors that affect those assumptions. Significant assumptions used to determine our projected pension obligation and related costs include discount rates, expected return on plan assets, and rate of compensation increases, while the assumptions used to determine our postretirement benefit obligation and related costs include discount rates and health care cost trends. See Note 5 of the Notes to the Consolidated Financial Statements for a full discussion of our employee benefit plans.

Stock-Based Compensation

We account for stock-based compensation under a fair value based method of accounting prescribed under ASC 718. Under the fair value method, compensation cost is measured at the grant date and remeasured each reporting period for liability-classified awards based on the fair value of an award and is recognized over the service period, which is usually the vesting period. To calculate the fair value, either a binomial or Black-Scholes valuation model may be used. The use of these models requires significant judgment with respect to expected life, volatility and other factors. Stock-based compensation cost for all types of awards is included in General and Administrative expense in the Consolidated Statement of Operations. See Note 11 of the Notes to the Consolidated Financial Statements for a full discussion of our stock-based compensation.

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Recently Issued Accounting Pronouncements

In May 2011, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) No. 2011-04, "Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRSs." The amendments in this update generally represent clarifications of Topic 820, but also include some instances where a particular principle or requirement for measuring fair value or disclosing information about fair value measurements has changed. This update results in common principles and requirements for measuring fair value and for disclosing information about fair value measurements in accordance with U.S. GAAP and IFRS. The amendments in this update are to be applied prospectively. The amendments are effective for interim and annual periods beginning after December 15, 2011. Early application is not permitted. We do not expect this guidance to have a significant impact on our consolidated financial position, results of operations or cash flows.

In June 2011, the FASB issued ASU No. 2011-05, "Presentation of Comprehensive Income." This update was amended in December 2011 by ASU No. 2011-12, "Deferral of the Effective Date for Amendments to the Presentation of Reclassifications of Items Out of Accumulated Other Comprehensive Income in Accounting Standards Update No. 2011-05." This update defers only those changes in update 2011-05 that relate to the presentation of reclassification adjustments. All other requirements in update 2011-05 are not affected by this update, including the requirement to report comprehensive income either in a single continuous financial statement or in two separate but consecutive financial statements. ASU No. 2011-05 and 2011-12 are effective for fiscal years (including interim periods) beginning after December 15, 2011. We do not expect this guidance to have a significant impact on our consolidated financial position, results of operations or cash flows.

In December 2011, the FASB issued ASU No. 2011-11, "Disclosures about Offsetting Assets and Liabilities." The amendments in this update require enhanced disclosures around financial instruments and derivative instruments that are either (1) offset in accordance with either ASC 210-20-45 or ASC 815-10-45 or (2) subject to an enforceable master netting arrangement or similar agreement, irrespective of whether they are offset in accordance with either ASC 210-20-45 or ASC 815-10-45. An entity should provide the disclosures required by those amendments retrospectively for all comparative periods presented. The amendments are effective during interim and annual periods beginning on or after January 1, 2013. We do not expect this guidance to have any impact on our consolidated financial position, results of operations or cash flows.

OTHER ISSUES AND CONTINGENCIES

Regulations. Our operations are subject to various types of regulation by federal, state and local authorities. See "Regulation of Oil and Natural Gas Exploration and Production," "Natural Gas Marketing, Gathering and Transportation," "Federal Regulation of Petroleum" and "Environmental Regulations" in the "Other Business Matters" section of Item 1 for a discussion of these regulations.

Restrictive Covenants. Our ability to incur debt and to make certain types of investments is subject to certain restrictive covenants in our various debt instruments. Among other requirements, our revolving credit agreement and our senior notes specify a minimum annual coverage ratio of operating cash flow to interest expense for the trailing four quarters of 2.8 to 1.0 and an asset coverage ratio of the present value of proved reserves plus working capital to debt of 1.75 to 1.0. Our revolving credit agreement also requires us to maintain a current ratio of 1.0 to 1.0. At December 31, 2011, we were in compliance in all material respects with all restrictive covenants on both the revolving credit agreement and senior notes. In the unforeseen event that we fail to comply with these covenants, we may apply for a temporary waiver with the lender, which, if granted, would allow us a period of time to remedy the situation.

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Operating Risks and Insurance Coverage. Our business involves a variety of operating risks. See "Risk Factors We face a variety of hazards and risks that could cause substantial financial losses" in Item 1A. In accordance with customary industry practice, we maintain insurance against some, but not all, of these risks and losses. The occurrence of any of these events not fully covered by insurance could have a material adverse effect on our financial position and results of operations. The costs of these insurance policies are somewhat dependent on our historical claims experience and also the areas in which we operate.

Commodity Pricing and Risk Management Activities. Our revenues, operating results, financial condition and ability to borrow funds or obtain additional capital depend substantially on prevailing prices for natural gas and oil. Declines in oil and gas prices may have a material adverse effect on our financial condition, liquidity, ability to obtain financing and operating results. Lower oil and gas prices also may reduce the amount of oil and gas that we can produce economically. Historically, oil and gas prices and markets have been volatile, with prices fluctuating widely, and they are likely to continue to be volatile. Depressed prices in the future would have a negative impact on our future financial results. In particular, substantially lower prices would significantly reduce revenue and could potentially trigger an impairment under ASC 360, "Property, Plant, and Equipment." Because our reserves are predominantly natural gas, changes in natural gas prices may have a more significant impact on our financial results.

The majority of our production is sold at market responsive prices. Generally, if the related commodity index falls, the price that we receive for our production will also decline. Therefore, the amount of revenue that we realize is partially determined by factors beyond our control. However, management may mitigate this price risk on all or a portion of our anticipated production with the use of derivative financial instruments. Most recently, we have used financial instruments such as collar and swap arrangements to reduce the impact of declining prices on our revenue. Under both arrangements, there is also a risk that the movement of index prices may result in our inability to realize the full benefit of an improvement in market conditions.

Forward-Looking Information

The statements regarding future financial and operating performance and results, market prices, future hedging activities, and other statements that are not historical facts contained in this report are forward-looking statements. The words "expect," "project," "estimate," "believe," "anticipate," "intend," "budget," "plan," "forecast," "predict," "may," "should," "could," "will" and similar expressions are also intended to identify forward-looking statements. Such statements involve risks and uncertainties, including, but not limited to, market factors, market prices (including geographic basis differentials) of natural gas and oil, results for future drilling and marketing activity, future production and costs, electronic, cyber or physical security breaches and other factors detailed herein and in our other Securities and Exchange Commission filings. See "Risk Factors" in Item 1A for additional information about these risks and uncertainties. Should one or more of these risks or uncertainties materialize, or should underlying assumptions prove incorrect, actual outcomes may vary materially from those indicated.

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RESULTS OF OPERATIONS

2011 and 2010 Compared

We reported net income for 2011 of $122.4 million, or $0.59 per share. During 2010, we reported net income of $103.4 million, or $0.50 per share. Net income increased in 2011 by $19.0 million, primarily due to increased operating revenues, partially offset by increased operating expenses, decreased gain on sale of assets and increased income tax and interest expenses. Operating revenues increased by $116.8 million largely due to increased natural gas and crude oil and condensate revenues, partially offset by a decrease in brokered natural gas revenues. Operating expenses increased by $33.4 million between periods primarily due to increases in transportation and gathering expenses, general and administrative expenses, depreciation, depletion and amortization and direct operations, partially offset by a decrease in impairment of oil and gas properties and lower brokered natural gas cost, taxes other than income and exploration expense.

Revenue, Price and Volume Variances

Below is a discussion of revenue, price and volume variances.

	Year Ended December 31,		Variance	
	2011	**2010**	**Amount**	**Percent**
Revenue Variances (In thousands)				
Natural Gas[1]	**$ 797,482**	$ 713,872	$ 83,610	12 %
Brokered Natural Gas	**51,190**	65,281	(14,091)	(22)%
Crude Oil and Condensate	**125,972**	79,091	46,881	59 %
Other	**6,185**	5,086	1,099	22 %

(1) *Natural Gas Revenues exclude the unrealized loss of $1.0 million and $0.2 million from the change in fair value of our derivatives not designated as hedges in 2011 and 2010, respectively.*

	Year Ended December 31,		Variance		Increase (Decrease)
	2011	**2010**	**Amount**	**Percent**	**(In thousands)**
Price Variances					
Natural Gas[1]	**$ 4.46**	$ 5.69	$ (1.23)	(22)%	$ (219,624)
Crude Oil and Condensate[2]	**$ 90.49**	$ 97.91	$ (7.42)	(8)%	(10,331)
Total					$ (229,955)
Volume Variances					
Natural Gas (Mmcf)	**178,848**	125,474	53,374	43%	$ 303,234
Crude Oil and Condensate (Mbbl)	**1,392**	808	584	72%	57,212
Total					$ 360,446

(1) *These prices include the realized impact of derivative instrument settlements, which increased the price by $0.47 per Mcf in 2011 and by $1.23 per Mcf in 2010.*

(2) *These prices include the realized impact of derivative instrument settlements, which increased the price by $1.01 per Bbl in 2011 and by $22.31 per Bbl in 2010.*

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Natural Gas Revenues

The increase in Natural Gas revenues of $83.6 million, excluding the impact of the unrealized losses discussed above, is primarily due to increased production, partially offset by lower realized natural gas prices. The increased production is primarily due to increased production associated with our Marcellus Shale drilling program in northeast Pennsylvania, partially offset by decreases in production primarily in east and south Texas due to normal production declines, the sale of oil and gas properties in Colorado, Utah and Wyoming and a shift from gas to oil projects.

Crude Oil and Condensate Revenues

The increase in Crude Oil and Condensate revenues of $46.9 million is primarily due to increased production, partially offset by lower realized oil prices. The increase in production is primarily due to our drilling program in the Eagle Ford oil shale in south Texas, partially offset by lower production in east Texas due to decreased activity.

Brokered Natural Gas Revenue and Cost

	Year Ended December 31, 2011	Year Ended December 31, 2010	Variance Amount	Variance Percent	Price and Volume Variances (In thousands)
Brokered Natural Gas Sales					
Sales Price ($/Mcf)	**$ 4.97**	$ 5.41	$ (0.44)	(8)%	$ (4,533)
Volume Brokered (Mmcf)	**x 10,303**	x 12,072	(1,769)	(15)%	(9,558)
Brokered Natural Gas Revenues (In thousands)	**$ 51,190**	$ 65,281			$ (14,091)
Brokered Natural Gas Purchases					
Purchase Price ($/Mcf)	**$ 4.25**	$ 4.68	$ (0.43)	(9)%	$ 4,353
Volume Brokered (Mmcf)	**x 10,303**	x 12,072	(1,769)	(15)%	8,279
Brokered Natural Gas Cost (In thousands)	**$ 43,834**	$ 56,466			$ 12,632
Brokered Natural Gas Margin (In thousands)	**$ 7,356**	$ 8,815			$ (1,459)

The decreased brokered natural gas margin of $1.5 million is primarily a result of a decrease in brokered volumes coupled with a decrease in the sales price that slightly outpaced the decrease in purchase price.

Impact of Derivative Instruments on Operating Revenues

The following table reflects the realized impact of cash settlements and the net unrealized change in fair value of derivative instruments:

	Year Ended December 31,			
	2011		2010	
(In thousands)	**Realized**	**Unrealized**	**Realized**	**Unrealized**
Operating Revenues Increase / (Decrease) to Revenue				
Cash Flow Hedges				
Natural Gas	**$ 84,937**	**$**	$ 154,960	$
Crude Oil	**1,403**		18,030	
Other Derivative Financial Instruments				
Natural Gas Basis Swaps		**(965)**		(226)
	$ 86,340	**$ (965)**	$ 172,990	$ (226)

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Operating and Other Expenses

(In thousands)	Year Ended December 31, 2011	2010	Variance Amount	Percent
Operating and Other Expenses				
Brokered Natural Gas Cost	**$ 43,834**	$ 56,466	$ (12,632)	(22)%
Direct Operations	**107,409**	99,642	7,767	8 %
Transportation and Gathering	**73,322**	19,069	54,253	285 %
Taxes Other Than Income	**27,576**	37,894	(10,318)	(27)%
Exploration	**36,447**	42,725	(6,278)	(15)%
Depreciation, Depletion and Amortization	**343,141**	327,083	16,058	5 %
Impairment of Oil and Gas Properties and Other Assets		40,903	(40,903)	(100)%
General and Administrative	**104,667**	79,177	25,490	32 %
Total Operating Expense	**$ 736,396**	$ 702,959	$ 33,437	5 %
(Gain) / Loss on Sale of Assets	**$ (63,382)**	$ (106,294)	$ (42,912)	(40)%
Interest Expense and Other	**71,663**	67,941	3,722	5 %
Income Tax Expense	**112,779**	95,112	17,667	19 %

Total costs and expenses from operations increased by $33.4 million from 2010 to 2011. The primary reasons for this fluctuation are as follows:

Brokered Natural Gas Cost decreased by $12.6 million from 2010 to 2011. See the preceding table titled "Brokered Natural Gas Revenue and Cost" for further analysis.

Direct Operations increased $7.8 million largely due to increased operating costs primarily driven by increased production. Contributing to the increase are higher workover and environmental and regulatory costs associated with the remediation of certain wells in northeast Pennsylvania as a result of the PaDEP consent order and settlement agreement. Offsetting these increases were lower lease maintenance, subsurface lease maintenance and plugging and abandonment costs in 2011 compared to 2010 coupled with lower compression expenses primarily due to the sale of our gathering system in northeast Pennsylvania in the fourth quarter of 2010.

Transportation and Gathering increased by $54.3 million primarily due to the commencement of various firm transportation and gathering arrangements in 2011, primarily in northeast Pennsylvania.

Taxes Other Than Income decreased $10.3 million due to decreased production taxes as a result of tax refunds and credits received in 2011 on qualifying wells, lower ad valorem tax expense due to lower natural gas prices and property values and lower franchise tax expense.

Exploration decreased $6.3 million due to lower geophysical and geological costs primarily due to a reduction in the acquisition of seismic data, partially offset by higher dry hole costs in 2011 related to an exploratory dry hole in Montana.

Depreciation, Depletion and Amortization increased by $16.1 million, of which $29.8 million was due to increased depreciation and depletion from increased capital spending and higher equivalent production volumes offset by a lower DD&A rate of $1.64 per Mcfe for 2011 compared to $2.12 per Mcfe for 2010 and a $1.4 million increase in accretion of asset retirement obligations. The increase in depletion and depreciation was partially offset by a decrease in amortization of unproved properties of $15.1 million primarily due to a decrease in amortization rates due to a shift in our drilling and development activities.

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Impairment of Oil and Gas Properties decreased by $40.9 million from 2011 to 2010 due to the impairment of two south Texas fields recognized as a result of continued price declines and limited activity and the impairment of drilling and service equipment in 2010. There were no impairments in 2011.

General and Administrative increased by $25.5 million primarily due to an increase in stock-based compensation expense of $25.1 million primarily associated with the mark to market of the liability portion of our performance shares as a result of our higher average stock price for the month of December 2011 compared to the average stock price for the month of December 2010. Higher incentive compensation and fringe benefits also contributed to the increase. These increases are partially offset by lower legal and professional costs associated with the PaDEP consent order and settlement agreement executed in 2010.

Gain / (Loss) on Sale of Assets

During 2011, we recognized a gain of $34.2 million from the sale of oil and gas properties in east Texas and an aggregate gain of $29.2 million related to the sale of various other assets as part of our ongoing asset portfolio management program.

During 2010, we recognized a gain of $49.3 million from the sale of our Pennsylvania gathering infrastructure, $40.7 million from the sale of our investment in Tourmaline and an aggregate gain of $16.3 million related to the sale of various other oil and gas properties and other assets during the year.

Interest Expense, Net

Interest Expense and Other increased by $3.7 million in 2011 compared to 2010 primarily due to an increase in the weighted-average effective interest rate on the credit facility, which increased to approximately 4.1% during the 2011 compared to approximately 3.8% during 2010, partially offset by a decrease in weighted-average borrowings under our credit facility based on average daily balances of $317.7 million during 2011 compared to average daily balances of $340.4 million during 2010. In addition, in December 2010, we issued $175 million aggregate principal amount of 5.58% weighted-average fixed rate notes, which increased interest expense recognized in 2011.

Income Tax Expense

Income Tax Expense increased by $17.7 million in 2011 compared to 2010 primarily due to increased pretax income and a slightly higher effective tax rate. The effective tax rates for 2011 and 2010 were 48.0% and 47.9%, respectively. The effective tax rate was slightly higher primarily due to an increase in our state rates used in establishing deferred income taxes mainly due to a continued shift in our state apportionment factors to higher rate states, primarily Pennsylvania, as a result of our continued focus on development of our Marcellus shale properties.

2010 and 2009 Compared

We reported net income for 2010 of $103.4 million, or $0.50 per share. During 2009, we reported net income of $148.3 million, or $0.72 per share. Net income decreased in 2010 by $45.0 million, primarily due to increased operating expenses, income tax and interest expenses and decreased operating revenues partially offset by increased gain on sale of assets. Operating revenues decreased by $30.0 million largely due to decreases in natural gas and brokered natural gas revenues, partially offset by an increase in crude oil and condensate revenues. Operating expenses increased by $95.4 million between periods due primarily to increases in depreciation, depletion and amortization, impairment of oil and gas properties and other assets, general and administrative expense, transportation and gathering and direct operations. These increases were partially offset by decreases in brokered natural gas cost, taxes other than income and exploration expense.

Revenue, Price and Volume Variances

Below is a discussion of revenue, price and volume variances.

	Year Ended December 31,		Variance	
	2010	2009	Amount	Percent
Revenue Variances (In thousands)				
Natural Gas[1]	$ 713,872	$ 745,497	$ (31,625)	(4)%
Brokered Natural Gas	65,281	75,283	(10,002)	(13)%
Crude Oil and Condensate	79,091	69,936	9,155	13 %
Other	5,086	4,323	763	18 %

(1) *Natural Gas Revenues exclude the unrealized loss from the change in fair value of our basis swaps of $0.2 million and $2.0 million in 2010 and 2009, respectively.*

	Year Ended December 31,		Variance		Increase (Decrease) (In thousands)
	2010	2009	Amount	Percent	
Price Variances					
Natural Gas[1]	$ 5.69	$ 7.61	$ (1.92)	(25)%	$ (241,357)
Crude Oil and Condensate[2]	$ 97.91	$ 85.52	$ 12.39	14 %	10,010
Total					$ (231,347)
Volume Variances					
Natural Gas (Mmcf)	125,474	97,914	27,560	28 %	$ 209,732
Crude Oil and Condensate (Mbbl)	808	818	(10)	(1)%	(855)
Total					$ 208,877

(1) *These prices include the realized impact of derivative instrument settlements, which increased the price by $1.23 per Mcf in 2010 and by $3.80 per Mcf in 2009.*

(2) *These prices include the realized impact of derivative instrument settlements, which increased the price by $22.31 per Bbl in 2010 and by $28.85 per Bbl in 2009.*

Natural Gas Revenues

The decrease in Natural Gas revenue of $31.6 million, excluding the impact of the unrealized losses discussed above, is due primarily to the decrease in realized natural gas prices, decreased production in east and south Texas associated with normal production declines, delays in completions and a shift from gas to oil projects, as well as the sale of our Canadian properties in April 2009. Partially offsetting these decreases was an increase in natural gas production in the northeast Pennsylvania associated with increased drilling and the start up of a portion of the Lathrop compressor station in the Marcellus shale at the end of the second quarter of 2010.

Crude Oil and Condensate Revenues

The $9.2 million increase in crude oil and condensate revenues is primarily due to an increase in realized crude oil prices and an increase in crude oil production in the Eagle Ford shale in south Texas and the Pettet formation production in east Texas. These increases are partially offset by lower

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production in West Virginia and northeast Pennsylvania as well as the sale of our Canadian properties in April 2009.

Brokered Natural Gas Revenue and Cost

	Year Ended December 31, 2010	Year Ended December 31, 2009	Variance Amount	Variance Percent	Price and Volume Variances (In thousands)
Brokered Natural Gas Sales					
Sales Price ($/Mcf)	$ 5.41	$ 5.95	$ (0.54)	(9)%	$ (6,527)
Volume Brokered (Mmcf)	x 12,072	x 12,656	(584)	(5)%	(3,475)
Brokered Natural Gas Revenues (In thousands)	$ 65,281	$ 75,283			$ (10,002)
Brokered Natural Gas Purchases					
Purchase Price ($/Mcf)	$ 4.68	$ 5.30	$ (0.62)	(12)%	$ 7,489
Volume Brokered (Mmcf)	x 12,072	x 12,656	(584)	(5)%	3,075
Brokered Natural Gas Cost (In thousands)	$ 56,466	$ 67,030			$ 10,564
Brokered Natural Gas Margin (In thousands)	$ 8,815	$ 8,253			$ 562

The increased brokered natural gas margin of $0.6 million is a result of a decrease in purchase price that outpaced the decrease in sales price, partially offset by a decrease in volumes brokered.

Impact of Derivative Instruments on Operating Revenues

The following table reflects the realized impact of cash settlements and the net unrealized change in fair value of derivative instruments:

(In thousands)	Year Ended December 31, 2010 Realized	2010 Unrealized	2009 Realized	2009 Unrealized
Operating Revenues Increase / (Decrease) to Revenue				
Cash Flow Hedges				
Natural Gas	$ 154,960	$	$ 371,915	$
Crude Oil	18,030		23,112	
Other Derivative Financial Instruments				
Natural Gas Basis Swaps		(226)		(1,954)
	$ 172,990	$ (226)	$ 395,027	$ (1,954)

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Operating and Other Expenses

(In thousands)	Year Ended December 31, 2010	2009	Variance Amount	Percent
Operating and Other Expenses				
Brokered Natural Gas Cost	$ 56,466	$ 67,030	$ (10,564)	(16)%
Direct Operations	99,642	93,985	5,657	6 %
Transportation and Gathering	19,069	13,809	5,260	38 %
Taxes Other Than Income	37,894	44,649	(6,755)	(15)%
Exploration	42,725	50,784	(8,059)	(16)%
Depreciation, Depletion and Amortization	327,083	251,260	75,823	30 %
Impairment of Oil and Gas Properties and Other Assets	40,903	17,622	23,281	132 %
General and Administrative	79,177	68,374	10,803	16 %
Total Operating Expense	$ 702,959	$ 607,513	$ 95,446	16 %
(Gain) / Loss on Sale of Assets	$ (106,294)	$ 3,303	$ (109,597)	(3,318)%
Interest Expense and Other	67,941	58,979	8,962	15 %
Income Tax Expense	95,112	74,947	20,165	27 %

Total costs and expenses from operations increased by $95.4 million from 2009 to 2010. The primary reasons for this fluctuation are as follows:

Brokered Natural Gas Cost decreased by $10.6 million from 2009 to 2010. See the preceding table titled "Brokered Natural Gas Revenue and Cost" for further analysis.

Direct Operations expenses increased by $5.7 million primarily due to lease maintenance expense and plug and abandonment costs in northeast Pennsylvania related to plugging and abandoning three vertical wells in accordance with the PaDEP's Second Modified Consent Order.

Transportation and Gathering costs increased by $5.3 million primarily due to the commencement of various firm transportation and gathering arrangements in 2010 primarily in northeast Pennsylvania.

Taxes Other Than Income decreased by $6.8 million primarily due to decreased production and ad valorem taxes due to lower natural gas prices and property values partially offset by increased business and occupational taxes and franchise taxes.

Exploration expense decreased by $8.1 million primarily due to lower dry hole costs as a result of drilling one dry hole in 2010 compared to two dry holes in 2009. The decrease was partially offset by higher geophysical and geological expenses associated with seismic purchases related to our Marcellus, Eagle Ford and Haynesville shale properties during 2010.

Depreciation, Depletion and Amortization increased by $75.8 million primarily due to increased depreciation and depletion from increased capital spending and higher equivalent production volumes, partially offset by a lower DD&A rate of $2.12 per Mcfe for 2010 compared to $2.14 per Mcfe in 2009. Amortization of unproved properties increased $17.6 million primarily due to increased unproved leasehold costs in northeast Pennsylvania and the Eagle Ford oil shale in south Texas in late 2009 and continuing into 2010.

Impairment of Oil and Gas Properties and Other Assets increased by $23.3 million from 2009 to 2010. Impairments in 2010 consisted of a $35.8 million impairment of two south Texas fields due to continued price declines and limited activity and a $5.1 million impairment related to drilling and service equipment. Impairments in 2009 consisted of a $17.6 million impairment of two fields in Colorado and south Texas due to lower well performance.

General and Administrative expenses increased by $10.8 million primarily due to a $9.9 million increase in legal expenses primarily related to the December 2010 PaDEP consent order and settlement agreement, ongoing litigation and related legal fees, a $8.3 million increase in pension expense primarily due to termination and amendment of our pension plans and a $2.4 million increase in incentive compensation. These increases were partially offset by an $8.5 million decrease in stock compensation expense primarily due to prior year awards that fully vested in February 2010 and a reduction in average stock price for the month of December 2010 compared to the average stock price for the month of December 2009.

Gain / (Loss) on Sale of Assets

During 2010, we recognized a gain of $49.3 million from the sale of our Pennsylvania gathering infrastructure, $40.7 million from the sale of our investment in Tourmaline and an aggregate gain of $16.3 million related to the sale of various other oil and gas properties and other assets during the year.

During 2009, we recognized a $16.0 million loss on sale of assets primarily due to the sale of our Canadian properties, partially offset by a $12.7 million gain on sale of assets related to the sale of oil and gas properties in West Virginia.

Interest Expense, Net

Interest expense, net increased by $9.0 million from 2009 to 2010 primarily due to an increase in weighted-average borrowings under our credit facility based on daily balances of approximately $340.4 million during 2010 compared to approximately $166.0 million during 2009, and to a lesser extent to the $175.0 million of debt we issued in December 2010. The weighted-average effective interest rate on the credit facility decreased to approximately 3.8% during 2010 compared to approximately 4.0% during 2009. Interest expense in 2010 also includes a make-whole premium payment of $2.8 million associated with the early payment of $75.0 million of the 7.33% fixed rate notes that were due in July 2011.

Income Tax Expense

Income tax expense increased by $20.2 million due to a higher effective tax rate offset by a decrease in our pre-tax income. The effective tax rates for 2010 and 2009 were 47.9% and 33.6%, respectively. The effective tax rate was higher primarily due to an increase in our state rates used in establishing deferred income taxes mainly due to a shift in our state apportionment factors to higher rate states, primarily in Pennsylvania, as a result of our increased focus on development of our Marcellus shale properties.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Market Risk

Our primary market risk is exposure to oil and natural gas prices. Realized prices are mainly driven by worldwide prices for oil and market prices for North American natural gas production. Commodity prices can be volatile and unpredictable.

Derivative Instruments and Hedging Activity

Our hedging strategy is designed to reduce the risk of price volatility for our production in the natural gas and crude oil markets. A hedging committee that consists of members of senior management oversees our hedging activity. Our hedging arrangements apply to only a portion of our production and provide only partial price protection. These hedging arrangements limit the benefit to

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us of increases in prices, but offer protection in the event of price declines. Further, if our counterparties defaulted, this protection might be limited as we might not receive the benefits of the hedges. Please read the discussion below as well as Note 12 of the Notes to the Consolidated Financial Statements for a more detailed discussion of our hedging arrangements.

Periodically, we enter into derivative commodity instruments to hedge our exposure to price fluctuations on natural gas and crude oil production. Our credit agreement restricts our ability to enter into commodity hedges other than to hedge or mitigate risks to which we have actual or projected exposure or as permitted under our risk management policies and not subjecting us to material speculative risks. All of our derivatives are used for risk management purposes and are not held for trading purposes. As of December 31, 2011, we had 37 derivative contracts open: 23 natural gas price swap arrangements, six natural gas basis swaps arrangements, three crude oil price swap arrangements and five natural gas collar arrangements. During 2011, we entered into 31 new derivative contracts covering anticipated natural gas and crude oil production for 2011, 2012, and 2013.

As of December 31, 2011, we had the following outstanding commodity derivatives:

Commodity and Derivative Type	Weighted-Average Contract Price	Volume	Contract Period	Net Unrealized Gain / (Loss) (In thousands)
Derivatives Designated as Hedging Instruments				
Natural Gas Swaps	$5.22 per Mcf	95,998 Mmcf	Jan. 2012 - Dec. 2012	**178,550**
Natural Gas Collars	$6.20 Ceiling/ $5.15 Floor per Mcf	17,729 Mmcf	Jan. 2013 - Dec. 2013	**21,429**
Crude Oil Swaps	$98.28 per Bbl	732 Mbbl	Jan. 2012 - Dec. 2012	**(387)**
				$ 199,592
Derivatives Not Designated as Hedging Instruments				
Natural Gas Basis Swaps	$(0.27) per Mcf	17,042 Mmcf	Jan. 2012 - Dec. 2012	**(3,107)**
				$ 196,485

The amounts set forth under the net unrealized gain / (loss) column in the tables above represent our total unrealized derivative position at December 31, 2011 and exclude the impact of nonperformance risk of $1.4 million. Nonperformance risk was primarily evaluated by reviewing credit default swap spreads for the various financial institutions in which we have derivative transactions, while our non-performance risk is evaluated using a market credit spread provided by our bank.

From time to time, we enter into natural gas and crude oil swap and collar agreements with counterparties to hedge price risk associated with a portion of our production. These cash flow hedges are not held for trading purposes. Under these price swaps, we receive a fixed price on a notional quantity of natural gas or crude oil in exchange for paying a variable price based on a market-based index, such as the NYMEX gas and crude oil futures. Under the collar agreements, if the index price rises above the ceiling price, we pay the counterparty. If the index price falls below the floor price, the counterparty pays us.

We had natural gas price swaps covering 74.9 Bcf, or 42%, of our 2011 natural gas production at an average price of $5.30 per Mcf.

We had one crude oil swap covering 275 Mbbl, or 20%, of our 2011 crude oil production, at an average price of $106.20 per Bbl.

During 2011, crude oil collars covered 365 Mbbl, or 26% of total crude oil production, at an average price of $90.88 per Bbl.

We are exposed to market risk on derivative instruments to the extent of changes in market prices of natural gas and crude oil. However, the market risk exposure on these derivative contracts is

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generally offset by the gain or loss recognized upon the ultimate sale of the commodity. Although notional contract amounts are used to express the volume of natural gas agreements, the amounts that can be subject to credit risk in the event of non-performance by third parties are substantially smaller. We do not anticipate any material impact on our financial results due to non-performance by third parties. Our primary derivative contract counterparties are Bank of America, Bank of Montreal, BNP Paribas, Goldman Sachs and JPMorgan.

The preceding paragraphs contain forward-looking information concerning future production and projected gains and losses, which may be impacted both by production and by changes in the future market prices of energy commodities. See "Forward-Looking Information" for further details.

Fair Market Value of Financial Instruments

The estimated fair value of financial instruments is the amount at which the instrument could be exchanged currently between willing parties. The carrying amounts reported in the Consolidated Balance Sheet for cash and cash equivalents, accounts receivable, and accounts payable approximate fair value due to the short-term maturities of these instruments.

The fair value of long-term debt is the estimated cost to acquire the debt, including a credit spread for the difference between the issue rate and the period end market rate. The credit spread is our default or repayment risk. The credit spread (premium or discount) is determined by comparing our fixed-rate notes and credit facility to new issuances (secured and unsecured) and secondary trades of similar size and credit statistics for both public and private debt. The fair value of all of the fixed-rate notes and the credit facility is based on interest rates currently available to us.

We use available market data and valuation methodologies to estimate the fair value of debt. The carrying amounts and fair values of long-term debt are as follows:

	December 31, 2011		December 31, 2010	
(In thousands)	**Carrying Amount**	**Estimated Fair Value**	**Carrying Amount**	**Estimated Fair Value**
Long-Term Debt	**$ 950,000**	**$ 1,082,531**	$ 975,000	$ 1,100,830

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of Cabot Oil & Gas Corporation:

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of operations, stockholders' equity, comprehensive income and of cash flows present fairly, in all material respects, the financial position of Cabot Oil & Gas Corporation and its subsidiaries (the "Company") at December 31, 2011 and 2010, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2011 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2011, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in Management's Report on Internal Control over Financial Reporting appearing under Item 9A. Our responsibility is to express opinions on these financial statements and on the Company's internal control over financial reporting based on our integrated 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 audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

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

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

/s/ PricewaterhouseCoopers LLP

Houston, Texas
February 28, 2012

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CABOT OIL & GAS CORPORATION

CONSOLIDATED STATEMENT OF OPERATIONS

(In thousands, except per share amounts)	Year Ended December 31, 2011	2010	2009
OPERATING REVENUES			
Natural Gas	**$ 796,517**	$ 713,646	$ 743,543
Brokered Natural Gas	**51,190**	65,281	75,283
Crude Oil and Condensate	**125,972**	79,091	69,936
Other	**6,185**	5,086	4,323
	979,864	863,104	893,085
OPERATING EXPENSES			
Brokered Natural Gas Cost	**43,834**	56,466	67,030
Direct Operations	**107,409**	99,642	93,985
Transportation and Gathering	**73,322**	19,069	13,809
Taxes Other Than Income	**27,576**	37,894	44,649
Exploration	**36,447**	42,725	50,784
Depreciation, Depletion and Amortization	**343,141**	327,083	251,260
Impairment of Oil and Gas Properties and Other Assets		40,903	17,622
General and Administrative	**104,667**	79,177	68,374
	736,396	702,959	607,513
Gain/(Loss) on Sale of Assets	**63,382**	106,294	(3,303)
INCOME FROM OPERATIONS	**306,850**	266,439	282,269
Interest Expense and Other	**71,663**	67,941	58,979
Income Before Income Taxes	**235,187**	198,498	223,290
Income Tax Expense	**112,779**	95,112	74,947
NET INCOME	**$ 122,408**	$ 103,386	$ 148,343
Earnings Per Share			
Basic	**$ 0.59**	$ 0.50	$ 0.72
Diluted	**$ 0.58**	$ 0.49	$ 0.71
Weighted-Average Common Shares Outstanding			
Basic	**208,498**	207,823	207,232
Diluted	**210,761**	210,390	209,365
Dividends Per Common Share	**$ 0.06**	$ 0.06	$ 0.06

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

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CABOT OIL & GAS CORPORATION

CONSOLIDATED BALANCE SHEET

(In thousands, except share amounts)	December 31, 2011	December 31, 2010
ASSETS		
Current Assets		
Cash and Cash Equivalents	$ 29,911	$ 55,949
Accounts Receivable, Net	114,381	94,488
Income Taxes Receivable	1,388	
Inventories	21,278	29,667
Derivative Instruments	174,263	16,926
Other Current Assets	4,579	5,978
Total Current Assets	345,800	203,008
Properties and Equipment, Net (Successful Efforts Method)	3,934,584	3,762,760
Derivative Instruments	21,249	
Other Assets	29,860	39,263
	$ 4,331,493	$ 4,005,031
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current Liabilities		
Accounts Payable	$ 217,294	$ 229,981
Income Taxes Payable		25,957
Deferred Income Taxes	55,132	
Accrued Liabilities	70,918	47,897
Total Current Liabilities	343,344	303,835
Pension and Postretirement Benefits	38,708	34,053
Long-Term Debt	950,000	975,000
Deferred Income Taxes	802,592	714,953
Asset Retirement Obligation	60,142	72,311
Other Liabilities	31,939	32,179
Total Liabilities	2,226,725	2,132,331
Commitments and Contingencies		
Stockholders' Equity		
Common Stock:		
Authorized 240,000,000 Shares of $0.10 Par Value in 2011 and 2010		
Issued 209,019,458 Shares and 208,420,168 Shares in 2011 and 2010, respectively	20,902	20,842
Additional Paid-in Capital	724,377	710,499
Retained Earnings	1,258,291	1,148,391
Accumulated Other Comprehensive Income / (Loss)	104,547	(3,683)
Less Treasury Stock, at Cost:		
404,400 Shares in 2011 and 2010, respectively	(3,349)	(3,349)
Total Stockholders' Equity	2,104,768	1,872,700
	$ 4,331,493	$ 4,005,031

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

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CABOT OIL & GAS CORPORATION

CONSOLIDATED STATEMENT OF CASH FLOWS

	Year Ended December 31,		
(In thousands)	**2011**	**2010**	**2009**
CASH FLOWS FROM OPERATING ACTIVITIES			
Net Income	**$ 122,408**	$ 103,386	$ 148,343
Adjustments to Reconcile Net Income to Cash Provided by Operating Activities:			
Depreciation, Depletion and Amortization	**343,141**	327,083	251,260
Impairment of Oil and Gas Properties and Other Assets		40,903	17,622
Deferred Income Tax Expense	**74,744**	61,809	101,815
(Gain) / Loss on Sale of Assets	**(63,382)**	(106,294)	3,303
Exploration Expense	**13,977**	11,657	50,784
Unrealized Loss / (Gain) on Derivative Instruments	**965**	226	1,954
Amortization of Debt Issuance Costs	**4,381**	3,381	3,635
Stock-Based Compensation, Pension and Other	**52,940**	29,794	31,126
Changes in Assets and Liabilities:			
Accounts Receivable, Net	**(19,893)**	(14,125)	28,725
Income Taxes	**(27,345)**	34,866	358
Inventories	**7,708**	(1,677)	17,687
Other Current Assets	**1,143**	3,675	3,103
Accounts Payable and Accrued Liabilities	**8,546**	(1,488)	(27,202)
Other Assets and Liabilities	**(17,494)**	(8,285)	(4,671)
Stock-Based Compensation Tax Benefit			(13,790)
Net Cash Provided by Operating Activities	**501,839**	484,911	614,052
CASH FLOWS FROM INVESTING ACTIVITIES			
Capital Expenditures	**(891,277)**	(857,251)	(611,207)
Proceeds from Sale of Assets	**403,657**	243,510	80,180
Net Cash Used in Investing Activities	**(487,620)**	(613,741)	(531,027)
CASH FLOWS FROM FINANCING ACTIVITIES			
Borrowings from Debt	**330,000**	525,000	105,000
Repayments of Debt	**(355,000)**	(355,000)	(167,000)
Stock-Based Compensation Tax Benefit			13,790
Dividends Paid	**(12,508)**	(12,467)	(12,432)
Capitalized Debt Issuance Costs	**(1,025)**	(13,821)	(10,409)
Other	**(1,724)**	909	83
Net Cash Provided by / (Used in) Financing Activities	**(40,257)**	144,621	(70,968)
Net Increase / (Decrease) in Cash and Cash Equivalents	**(26,038)**	15,791	12,057
Cash and Cash Equivalents, Beginning of Period	**55,949**	40,158	28,101
Cash and Cash Equivalents, End of Period	**$ 29,911**	$ 55,949	$ 40,158

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

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CABOT OIL & GAS CORPORATION

CONSOLIDATED STATEMENT OF STOCKHOLDERS' EQUITY

(In thousands, except per share amounts)	Common Shares	Stock Par	Treaury Shares	Treasury Stock	Paid-In Capital	Accumulated Other Comprehensive Income / (Loss)	Retained Earnings	Total
Balance at December 31, 2008	207,122	$ 20,712	404	$ (3,349)	$ 665,212	$ 186,426	$ 921,561	$ 1,790,562
Net Income							148,343	148,343
Exercise of Stock Options and Stock Appreciation Rights	28	4			51			55
Tax Benefit of Stock-Based Compensation					13,790			13,790
Stock Amortization and Vesting	562	56			14,870			14,926
Sale of Stock Held in Rabbi Trust					1,260			1,260
Cash Dividends at $0.06 per Share							(12,432)	(12,432)
Other Comprehensive Income / (Loss)						(143,990)		(143,990)
Balance at December 31, 2009	207,712	$ 20,772	404	$ (3,349)	$ 695,183	$ 42,436	$ 1,057,472	$ 1,812,514
Net Income							103,386	103,386
Exercise of Stock Options and Stock Appreciation Rights	78	8			762			770
Tax Benefit of Stock-Based Compensation					108			108
Stock Amortization and Vesting	630	62			12,868			12,930
Sale of Stock Held in Rabbi Trust					1,578			1,578
Cash Dividends at $0.06 per Share							(12,467)	(12,467)
Other Comprehensive Income / (Loss)						(46,119)		(46,119)
Balance at December 31, 2010	208,420	$ 20,842	404	$ (3,349)	$ 710,499	$ (3,683)	$ 1,148,391	$ 1,872,700
Net Income							122,408	122,408
Exercise of Stock Options and Stock Appreciation Rights	159	16			(1,762)			(1,746)
Stock Amortization and Vesting	440	44			13,906			13,950
Sale of Stock Held in Rabbi Trust					1,734			1,734
Cash Dividends at $0.06 per Share							(12,508)	(12,508)
Other Comprehensive Income / (Loss)						108,230		108,230
Balance at December 31, 2011	**209,019**	**$ 20,902**	**404**	**$ (3,349)**	**$ 724,377**	**$ 104,547**	**$ 1,258,291**	**$ 2,104,768**

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

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CABOT OIL & GAS CORPORATION

CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME

	Year Ended December 31,					
(In thousands)	**2011**		**2010**		**2009**	
Net Income		**$ 122,408**		$ 103,386		$ 148,343
Other Comprehensive Income / (Loss), net of taxes:						
Reclassification Adjustment for Settled Contracts, net of taxes of $33,500, $65,734 and $147,048, respectively		**(52,840)**		(107,256)		(247,979)
Changes in Fair Value of Hedge Positions, net of taxes of $(103,963), $(29,777) and $(57,303), respectively		**163,704**		45,878		96,783
Defined Benefit Pension and Postretirement Plans:						
Net Gain / (Loss) Arising During the Year, net of taxes of $9,085, $(3,245) and $1,773, respectively	**$ (13,814)**		$ 5,693		$ (3,009)	
Effect of Plan Termination and Amendment, net of taxes of $0, $(310) and $0, respectively			506			
Settlement, net of taxes of $(2,143), $(1,528) and $0, respectively	**3,380**		2,493			
Amortization of Net Obligation at Transition, net of taxes of $(245), $(240) and $(236), respectively	**387**		392		396	
Amortization of Prior Service Cost, net of taxes of $(406), $(217) and (267), respectively	**640**		355		450	
Amortization of Net Loss, net of taxes of $(4,257), $(3,548) and $(1,432), respectively	**6,718**	**(2,689)**	5,788	15,227	2,422	259
Foreign Currency Translation Adjustment, net of taxes of $(34), $(20) and $(4,116), respectively		**55**		32		6,947
Total Other Comprehensive Income / (Loss)		**108,230**		(46,119)		(143,990)
Comprehensive Income		**$ 230,638**		$ 57,267		$ 4,353

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

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CABOT OIL & GAS CORPORATION

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

1. Summary of Significant Accounting Policies

Basis of Presentation and Nature of Operations

Cabot Oil & Gas Corporation and its subsidiaries are engaged in the development, exploitation, exploration, production and marketing of natural gas, crude oil and, to a lesser extent, natural gas liquids exclusively within the continental United States. The Company also transports, stores, gathers and purchases natural gas for resale. The Company's exploration and development activities are concentrated in areas with known hydrocarbon resources, which are conducive to multi-well, repeatable drilling programs.

The Company operates in one segment, natural gas and oil development, exploitation and exploration. The Company's oil and gas properties are managed as a whole rather than through discrete operating segments or business units. Operational information is tracked by geographic area; however, financial performance is assessed as a single enterprise and not on a geographic basis. Allocation of resources is made on a project basis across the Company's entire portfolio without regard to geographic areas.

The consolidated financial statements contain the accounts of the Company and its subsidiaries after eliminating all significant intercompany balances and transactions. Certain reclassifications have been made to prior year statements to conform with current year presentation. These reclassifications have no impact on net income.

On January 3, 2012, the Board of Directors declared a 2-for-1 split of the Company's common stock in the form of a stock dividend. The stock dividend was distributed on January 25, 2012 to shareholders of record as of January 17, 2012. All common stock accounts and per share data have been retroactively adjusted to give effect to the 2-for-1 split of the Company's common stock.

Recently Issued Accounting Pronouncements

In May 2011, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) No. 2011-04, "Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRSs." The amendments in this update generally represent clarifications of Topic 820, but also include some instances where a particular principle or requirement for measuring fair value or disclosing information about fair value measurements has changed. This update results in common principles and requirements for measuring fair value and for disclosing information about fair value measurements in accordance with U.S. GAAP and IFRS. The amendments in this update are to be applied prospectively. The amendments are effective for interim and annual periods beginning after December 15, 2011. Early application is not permitted. The Company does not expect this guidance to have a significant impact on its consolidated financial position, results of operations or cash flows.

In June 2011, the FASB issued ASU No. 2011-05, "Presentation of Comprehensive Income." This update was amended in December 2011 by ASU No. 2011-12, "Deferral of the Effective Date for Amendments to the Presentation of Reclassifications of Items Out of Accumulated Other Comprehensive Income in Accounting Standards Update No. 2011-05." This update defers only those changes in update 2011-05 that relate to the presentation of reclassification adjustments. All other requirements in update 2011-05 are not affected by this update, including the requirement to report comprehensive income either in a single continuous financial statement or in two separate but consecutive financial statements. ASU No. 2011-05 and 2011-12 are effective for fiscal years (including

CABOT OIL & GAS CORPORATION

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

1. Summary of Significant Accounting Policies (Continued)

interim periods) beginning after December 15, 2011. The Company does not expect this guidance to have a significant impact on its consolidated financial position, results of operations or cash flows.

In December 2011, the FASB issued ASU No. 2011-11, "Disclosures about Offsetting Assets and Liabilities." The amendments in this update require enhanced disclosures around financial instruments and derivative instruments that are either (1) offset in accordance with either ASC 210-20-45 or ASC 815-10-45 or (2) subject to an enforceable master netting arrangement or similar agreement, irrespective of whether they are offset in accordance with either ASC 210-20-45 or ASC 815-10-45. An entity should provide the disclosures required by those amendments retrospectively for all comparative periods presented. The amendments are effective during interim and annual periods beginning on or after January 1, 2013. The Company does not expect this guidance to have any impact on its consolidated financial position, results of operations or cash flows.

Cash and Cash Equivalents

The Company considers all highly liquid short-term investments with original maturities of three months or less to be cash equivalents. Cash and cash equivalents were primarily concentrated in one financial institution at December 31, 2011 and 2010. The Company periodically assesses the financial condition of these institutions and considers any possible credit risk to be minimal.

Inventories

Inventories are comprised of natural gas in storage, tubular goods and well equipment and pipeline imbalances. All inventory balances are carried at the lower of average cost or market.

Natural gas gathering and pipeline operations normally include imbalance arrangements with the pipeline. The volumes of natural gas due to or from the Company under imbalance arrangements are recorded at actual selling or purchase prices, as the case may be, and are adjusted monthly to reflect market changes. The net pipeline imbalance is included in inventory in the Consolidated Balance Sheet.

Allowance for Doubtful Accounts

The Company records an allowance for doubtful accounts for receivables that the Company determines to be uncollectible based on the specific identification basis. The allowance for doubtful accounts, which is netted against Accounts Receivable in the Consolidated Balance Sheet, was $3.3 million and $4.1 million at December 31, 2011 and 2010, respectively.

Accounts Payable

This account may include credit balances from outstanding checks in zero balance cash accounts. These credit balances are referred to as book overdrafts and are included as a component of Accounts Payable on the Consolidated Balance Sheet. There were no credit balances from outstanding checks in zero balance cash accounts included in Accounts Payable at December 31, 2011 and 2010 as sufficient cash was available for offset.

Properties and Equipment

The Company uses the successful efforts method of accounting for oil and gas producing activities. Under this method, acquisition costs for proved and unproved properties are capitalized when incurred.

CABOT OIL & GAS CORPORATION

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

1. Summary of Significant Accounting Policies (Continued)

Exploration costs, including geological and geophysical costs, the costs of carrying and retaining unproved properties and exploratory dry hole drilling costs, are expensed. Development costs, including the costs to drill and equip development wells and successful exploratory drilling costs to locate proved reserves are capitalized.

Exploratory drilling costs are capitalized when incurred pending the determination of whether a well has found proved reserves. The determination is based on a process which relies on interpretations of available geologic, geophysical, and engineering data. If a well is determined to be successful, the capitalized drilling costs will be reclassified as part of the cost of the well. If a well is determined to be unsuccessful, the capitalized drilling costs will be charged to exploration expense in the period the determination is made. If an exploratory well requires a major capital expenditure before production can begin, the cost of drilling the exploratory well will continue to be carried as an asset pending determination of whether proved reserves have been found only as long as: i) the well has found a sufficient quantity of reserves to justify its completion as a producing well if the required capital expenditure is made and ii) drilling of the additional exploratory wells is under way or firmly planned for the near future. If drilling in the area is not under way or firmly planned, or if the well has not found a commercially producible quantity of reserves, the exploratory well is assumed to be impaired and its costs are charged to exploration expense.

Development costs of proved oil and gas properties, including estimated dismantlement, restoration and abandonment costs and acquisition costs, are depreciated and depleted on a field basis by the units-of-production method using proved developed and proved reserves, respectively. Properties related to gathering and pipeline systems and equipment are depreciated using the straight-line method based on estimated useful lives ranging from 10 to 25 years. Generally pipeline and transmission systems are depreciated over 12 to 25 years, gathering and compression equipment is depreciated over 10 years and storage equipment and facilities are depreciated over 10 to 16 years. Buildings are depreciated on a straight-line basis over 25 to 40 years. Certain other assets are depreciated on a straight-line basis over 3 to 10 years.

Costs of retired, sold or abandoned properties that make up a part of an amortization base (partial field) are charged to accumulated depreciation, depletion and amortization if the units-of-production rate is not significantly affected. Accordingly, a gain or loss, if any, is recognized only when a group of proved properties (entire field) that make up the amortization base has been retired, abandoned or sold.

The Company evaluates its oil and gas properties and other assets for impairment whenever events or changes in circumstances indicate an asset's carrying amount may not be recoverable. The Company compares expected undiscounted future cash flows to the net book value of the asset. If the future undiscounted expected cash flows, based on estimates of future crude oil and natural gas prices, operating costs and anticipated production from proved reserves are lower than the net book value of the asset, the capitalized cost is reduced to fair value. Commodity pricing is estimated by using a combination of assumptions management uses in its budgeting and forecasting process as well as historical and current prices adjusted for geographical location and quality differentials, as well as other factors that management believes will impact realizable prices. Fair value is calculated by discounting the future cash flows. The discount factor used is based on rates utilized by market participants that are commensurate with the risks inherent in the development and production of the underlying natural gas and crude oil.

CABOT OIL & GAS CORPORATION

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

1. Summary of Significant Accounting Policies (Continued)

Costs attributable to the Company's unproved properties are not subject to the impairment analysis described above; however, a portion of the costs associated with such properties is subject to amortization based on past drilling and exploration experience and average property lives. Average property lives are determined on a geographical basis and based on the estimated life of unproved property leasehold rights. During 2011, 2010 and 2009, amortization associated with the Company's unproved properties was $32.5 million, $47.6 million and $30.0 million, respectively, and is included in Depreciation, Depletion, and Amortization in the Consolidated Statement of Operations.

Asset Retirement Obligations

The Company records the fair value of a liability for an asset retirement obligation in the period in which it is incurred if a reasonable estimate of fair value can be made. The associated asset retirement cost is capitalized as part of the carrying amount of the long-lived asset. Subsequently, the asset retirement cost is allocated to expense using a systematic and rational method over the asset's useful life. The majority of the asset retirement obligations recorded by the Company relate to the plugging and abandonment of oil and gas wells. However, liabilities are also recorded for meter stations, pipelines, processing plants and compressors. At December 31, 2011, there were no assets legally restricted for purposes of settling asset retirement obligations.

Additional retirement obligations increase the liability associated with new oil and gas wells and other facilities as these obligations are incurred. Accretion expense is included in Depreciation, Depletion and Amortization expense on the Company's Consolidated Statement of Operations.

Risk Management Activities

From time to time, the Company enters into derivative contracts, such as natural gas and crude oil price swaps or zero-cost price collars, as a hedging strategy to manage commodity price risk associated with its production or other contractual commitments. All hedge transactions are subject to the Company's risk management policy which does not permit speculative trading activities. Gains or losses on these hedging activities are generally recognized over the period that its production or other underlying commitment is hedged as an offset to the specific hedged item. Cash flows related to any recognized gains or losses associated with these hedges are reported as cash flows from operations. If a hedge is terminated prior to expected maturity, gains or losses are deferred and included in income in the same period that the underlying production or other contractual commitment is delivered. Unrealized gains or losses associated with any derivative contract not considered a hedge are recognized currently in the results of operations.

When the designated item associated with a derivative instrument matures or is sold, extinguished or terminated, derivative gains or losses are recognized as part of the gain or loss on the sale or settlement of the underlying item. For example, in the case of natural gas price hedges, the gain or loss is reflected in natural gas revenue. When a derivative instrument is associated with an anticipated transaction that is no longer expected to occur or if the hedge is no longer effective, the gain or loss on the derivative is recognized currently in the results of operations to the extent the market value changes in the derivative have not been offset by the effects of the price changes on the hedged item since the inception of the hedge.

Effective January 1, 2009, the Company adopted the amended disclosure requirements prescribed in ASC 815, "Derivatives and Hedging."

CABOT OIL & GAS CORPORATION

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

1. Summary of Significant Accounting Policies (Continued)

Revenue Recognition

Gas Imbalances

The Company applies the sales method of accounting for natural gas revenue. Under this method, revenues are recognized based on the actual volume of natural gas sold to purchasers. Natural gas production operations may include joint owners who take more or less than the production volumes entitled to them on certain properties. Production volume is monitored to minimize these natural gas imbalances. A natural gas imbalance liability is recorded at the actual price realized upon the gas sale in Accounts Payable in the Consolidated Balance Sheet if the Company's excess takes of natural gas exceed its estimated remaining proved developed reserves for these properties.

Brokered Natural Gas Margin

The revenues and expenses related to brokering natural gas are reported gross as part of Operating Revenues and Operating Expenses in accordance with ASC 605-45, "Revenue Recognition: Principle Agent Considerations". The Company realizes brokered margin as a result of buying and selling natural gas utilizing separate purchase and sale transactions, typically with separate counterparties, whereby the Company and/or the counterparty takes title to the natural gas purchased or sold. The Company realized $7.4 million, $8.8 million and $8.3 million of brokered natural gas margin in 2011, 2010 and 2009, respectively.

Natural Gas Measurement

The Company records estimated amounts for natural gas revenues and natural gas purchase costs based on volumetric calculations under its natural gas sales and purchase contracts. Variances or imbalances resulting from such calculations are inherent in natural gas sales, production, operation, measurement, and administration. Management does not believe that differences between actual and estimated natural gas revenues or purchase costs attributable to the unresolved variances or imbalances are material.

Income Taxes

The Company follows the asset and liability method of accounting for income taxes. Under this method, deferred tax assets and liabilities are recorded for the estimated future tax consequences attributable to the differences between the financial carrying amounts of existing assets and liabilities and their respective tax basis. Deferred tax assets and liabilities are measured using the tax rate in effect for the year in which those temporary differences are expected to reverse. The effect of a change in tax rates on deferred tax assets and liabilities is recognized in the year of the enacted rate change. A valuation allowance is established to reduce deferred tax assets if it is more likely than not that the related tax benefits will not be realized.

The Company is required to make judgments, including estimating reserves for potential adverse outcomes regarding tax positions that the Company has taken. The Company accounts for uncertainty in income taxes using a recognition and measurement threshold for tax positions taken or expected to be taken in a tax return. The tax benefit from an uncertain tax position is recognized when it is more likely than not that the position will be sustained upon examination by taxing authorities based on technical merits of the position. The amount of the tax benefit recognized is the largest amount of the

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CABOT OIL & GAS CORPORATION

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

1. Summary of Significant Accounting Policies (Continued)

benefit that has a greater than 50% likelihood of being realized upon ultimate settlement. The effective tax rate and the tax basis of assets and liabilities reflect management's estimates of the ultimate outcome of various tax uncertainties.

The Company recognizes accrued interest related to uncertain tax positions in Interest Expense and Other and accrued penalties related to such positions in General and Administrative expense in the Consolidated Statement of Operations.

Stock-Based Compensation

The Company accounts for stock-based compensation under a fair value based method of accounting prescribed under ASC 718. Under the fair value method, compensation cost is measured at the grant date and remeasured each reporting period for liability-classified awards based on the fair value of an award and is recognized over the service period, which is usually the vesting period. To calculate the fair value, either a binomial or Black-Scholes valuation model may be used. Stock-based compensation cost for all types of awards is included in General and Administrative expense in the Consolidated Statement of Operations.

The tax benefit for stock-based compensation is included as both a cash inflow from financing activities and a cash outflow from operating activities in the Consolidated Statement of Cash Flows. In accordance with ASC 718, the Company recognizes a tax benefit only to the extent it reduces the Company's income taxes payable. The Company did not recognize a tax benefit for stock-based compensation for the years ended December 31, 2011 and 2010. For the year ended December 31, 2009, the Company realized tax benefits of $13.8 million.

Environmental Matters

Environmental expenditures are expensed or capitalized, as appropriate, depending on their future economic benefit. Expenditures that relate to an existing condition caused by past operations, and that do not have future economic benefit are expensed. Liabilities related to future costs are recorded on an undiscounted basis when environmental assessments and/or remediation activities are probable and the costs can be reasonably estimated. Any insurance recoveries are recorded as assets when received.

Market Risk

The Company's primary market risk is exposure to oil and natural gas prices. Realized prices are mainly driven by worldwide prices for oil and spot market prices for North American natural gas production. Commodity prices are volatile and unpredictable.

Credit Risk

Although notional contract amounts are used to express the volume of natural gas price agreements, the amounts that can be subject to credit risk in the event of non-performance by third parties are substantially smaller. The Company does not anticipate any material impact on its financial results due to non-performance by the third parties.

In 2011, the Company did not have any one customer account for greater than 10% of the Company's total sales. In 2010, one customer accounted for approximately 11%, of the Company's total sales. In 2009, two customers accounted for approximately 13% and 11%, respectively of the Company's total sales.

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CABOT OIL & GAS CORPORATION

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

1. Summary of Significant Accounting Policies (Continued)

Use of Estimates

In preparing financial statements, the Company follows generally accepted accounting principles. These principles require management to make estimates and assumptions that affect the reported amounts of assets and liabilities, the 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. The most significant estimates pertain to proved natural gas, natural gas liquids and crude oil reserves and related cash flow estimates used in impairment tests of oil and gas properties, natural gas, natural gas liquids and crude oil revenues and expenses, current values of derivative instruments, as well as estimates of expenses related to legal, environmental and other contingencies, depreciation, depletion and amortization, asset retirement obligations, pension and postretirement obligations, stock-based compensation and deferred income taxes. Actual results could differ from those estimates.

2. Properties and Equipment, Net

Properties and equipment, net are comprised of the following:

	December 31,	
(In thousands)	**2011**	**2010**
Proved Oil and Gas Properties	**$ 5,006,846**	$ 4,794,650
Unproved Oil and Gas Properties	**478,942**	490,181
Gathering and Pipeline Systems	**238,660**	237,043
Land, Building and Other Equipment	**80,908**	86,248
	5,805,356	5,608,122
Accumulated Depreciation, Depletion and Amortization	**(1,870,772)**	(1,845,362)
	$ 3,934,584	$ 3,762,760

Capitalized Exploratory Well Costs

The following table reflects the net changes in capitalized exploratory well costs during 2011, 2010 and 2009.

		December 31,	
(In thousands)	**2011**	**2010**	**2009**
Beginning balance at January 1	**$ 4,285**	$ 4,179	$ 5,990
Additions to capitalized exploratory well costs pending the determination of proved reserves	**5,328**	4,285	4,179
Reclassifications to wells, facilities, and equipment based on the determination of proved reserves	**(1,138)**	(4,148)	(762)
Capitalized exploratory well costs charged to expense	**(3,147)**	(31)	(5,228)
Ending balance at December 31	**$ 5,328**	$ 4,285	$ 4,179

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CABOT OIL & GAS CORPORATION

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

2. Properties and Equipment, Net (Continued)

The following table provides an aging of capitalized exploratory well costs based on the date the drilling was completed for which exploratory well costs have been capitalized for a period greater than one year since the completion of drilling:

	December 31,		
(In thousands)	**2011**	**2010**	**2009**
Capitalized exploratory well costs that have been capitalized for a period of one year or less	**$ 5,328**	$ 4,285	$ 4,179
Capitalized exploratory well costs that have been capitalized for a period greater than one year			
Balance at December 31	**$ 5,328**	$ 4,285	$ 4,179

Impairments

During 2010, the Company recorded $40.9 million of impairments of oil and gas properties and other assets. The Company recorded a $35.8 million impairment of oil and gas properties due to continued price declines and limited activity in two south Texas fields. These fields were reduced to a fair value of approximately $15.4 million. An impairment of $5.1 million was recorded related to drilling and service equipment that was primarily used for drilling in West Virginia. The impairment was a result of decreased activity in West Virginia and the decision to sell the underlying assets. These assets were reduced to fair value of approximately $4.0 million.

The Company also recorded an impairment loss of approximately $5.8 million during 2010 associated with the sale of certain properties in Colorado, which was recognized in the Gain / (Loss) on Sale of Assets in the Consolidated Statement of Operations. The fair value of the impaired properties was approximately $3.0 million and was determined using a market approach which considered the execution of a purchase and sale agreement the Company entered into on June 30, 2010. Accordingly, the inputs associated with the fair value of assets held for sale were considered Level 2 in the fair value hierarchy.

During 2009, the Company recorded $17.6 million of impairments of oil and gas properties. The Company recorded an impairment of $12.0 million and $5.6 million in the Fossil Federal field in San Miguel County, Colorado and the Beaurline field in Hildalgo County, Texas, respectively, due to lower well performance. These fields were reduced to fair value of approximately $8.9 million.

Fair value of oil and gas properties was determined using the income approach utilizing discounted future cash flows. The fair value of the impaired oil and gas properties and other assets was based on significant inputs that were not observable in the market and are considered to be Level 3 inputs as defined in ASC 820. Refer to Note 13 for more information and a description of fair value hierarchy. Key assumptions include (1) oil and natural gas prices (adjusted to quality and basis differentials), (2) projections of estimated quantities of oil and gas reserves and production, (3) estimates of future development and production costs and (4) risk adjusted discount rates (14% at September 30, 2010 and 16% at December 31, 2009, respectively). Fair value of drilling and service equipment was determined using the market approach which considered broker quotes from market participants in the oil field services sector.

CABOT OIL & GAS CORPORATION

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

2. Properties and Equipment, Net (Continued)

Natural gas prices have decreased from an average price of $4.39 per Mmbtu in 2010 to an average price of $4.04 per Mmbtu in 2011. Natural gas prices were $3.36 per Mmbtu in December 2011 and have continued to decline to $2.68 per Mmbtu in February 2012. Natural gas prices represent the first of the month Henry Hub index price per Mmbtu. Oil prices have increased from an average price of $77.32 per barrel in 2010 to an average price of $94.01 per barrel in 2011. Any further decline in natural gas prices or quantities could result in an impairment of proved oil and gas properties.

Divestitures

The Company recognized an aggregate gain on sale of assets of $63.4 million and $106.3 million for the years ended December 3, 2011 and 2010, respectively, and an aggregate loss of $3.3 million for the year ended December 31, 2009.

In October 2011, the Company sold certain proved oil and gas properties located in Colorado, Utah and Wyoming to Breitburn Operating L.P., a wholly owned subsidiary of Breitburn Energy Partners L.P. for $285.0 million. The Company received $283.2 million in cash proceeds, after closing adjustments, and recognized a $4.2 million gain on sale of assets.

In May 2011, the Company sold certain of its unproved Haynesville and Bossier Shale oil and gas properties in east Texas to a third party. The Company received approximately $47.0 million in cash proceeds and recognized a $34.2 million gain on sale of assets.

In February and April 2011, respectively, the Company entered into two participation agreements with third parties related to certain of its Haynesville and Bossier Shale leaseholds in east Texas. Under the terms of the participation agreements, the third parties will fund 100% of the cost to drill and complete certain Haynesville and Bossier Shale wells in the related leaseholds over a multi-year period in exchange for a 75% working interest in the leaseholds. During 2011, the Company received a reimbursement of drilling costs incurred of approximately $12.9 million associated with wells that had commenced drilling prior to the execution of the participation agreements.

In 2011, the Company also sold various other unproved properties and other assets for total proceeds of $73.5 million and recognized an aggregate gain of $25.0 million.

In December 2010, the Company sold its existing Pennsylvania gathering infrastructure of approximately 75 miles of pipeline and two compressor stations to Williams Field Services (Williams), a subsidiary of Williams Partners L.P., for $150 million. Under the terms of the purchase and sale agreement, the Company was obligated to construct pipelines to connect certain of its 2010 program wells, complete the construction of the Lathrop compressor station and complete taps into certain pipeline delivery points. These obligations were completed in 2011. As of December 31, 2010, the Company recognized a $49.3 million gain on sale of assets, which included the accrual of $17.9 million associated with the obligations described above. The Company also entered into a 25-year firm gathering contract with Williams that requires Williams to complete construction of approximately 32 miles of high pressure pipeline, 65 miles of trunklines and two compressor stations in Susquehanna County, Pennsylvania in the next two years. Additionally, Williams will connect all of the Company's drilling program wells, which will connect our production to five interstate pipeline delivery options.

In 2010, the Company also sold various other proved and unproved properties and other assets for total proceeds of $32.2 million and recognized an aggregate gain of $16.3 million.

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CABOT OIL & GAS CORPORATION

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

2. Properties and Equipment, Net (Continued)

In April 2009, the Company sold substantially all of its Canadian proved oil and gas properties to Tourmaline Oil Corporation (Tourmaline) for total consideration of $84.4 million ($63.8 million in cash and $20.6 million in common stock of Tourmaline) and recognized a loss of approximately $16.0 million. The common stock investment was accounted for using the cost method. In November 2010, the Company sold its investment in common stock of Tourmaline for $61.3 million and recognized a gain of $40.7 million which is included in Gain/(Loss) on Sale of Assets in the Consolidated Statement of Operations.

In 2009, the Company also sold certain oil and gas properties in West Virginia for cash proceeds of $11.4 million and recognized a gain of $12.7 million.

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CABOT OIL & GAS CORPORATION

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

3. Additional Balance Sheet Information

Certain balance sheet amounts are comprised of the following:

(In thousands)	December 31, 2011	December 31, 2010
ACCOUNTS RECEIVABLE, NET		
Trade Accounts	**$ 111,306**	$ 91,077
Joint Interest Accounts	**5,417**	4,901
Other Accounts	**1,003**	2,603
	117,726	98,581
Allowance for Doubtful Accounts	**(3,345)**	(4,093)
	$ 114,381	94,488
INVENTORIES		
Natural Gas in Storage	**$ 13,513**	$ 13,371
Tubular Goods and Well Equipment	**7,146**	17,072
Pipeline Imbalances	**619**	(776)
	$ 21,278	$ 29,667
OTHER CURRENT ASSETS		
Drilling Advances	**$ 55**	$ 2,796
Prepaid Balances	**2,290**	2,925
Restricted Cash	**2,234**	
Deferred Income Taxes		257
	$ 4,579	$ 5,978
OTHER ASSETS		
Rabbi Trust Deferred Compensation Plan	**$ 10,838**	$ 15,788
Debt Issuance Cost	**17,680**	22,061
Other Accounts	**1,342**	1,414
	$ 29,860	$ 39,263
ACCOUNTS PAYABLE		
Trade Accounts	**$ 18,253**	$ 27,401
Natural Gas Purchases	**3,012**	3,596
Royalty and Other Owners	**48,113**	36,034
Accrued Capital Costs	**138,122**	146,824
Taxes Other Than Income	**2,076**	2,655
Drilling Advances	**1,489**	523
Wellhead Gas Imbalances	**2,312**	5,142
Other Accounts	**3,917**	7,806
	$ 217,294	$ 229,981
ACCRUED LIABILITIES		

Employee Benefits	**$**	**26,035**	$	10,790
Pension and Postretirement Benefits		**6,331**		1,688
Taxes Other Than Income		**12,297**		14,576
Interest Payable		**24,701**		19,488
Derivative Contracts		**385**		
Other Accounts		**1,169**		1,355
	$	**70,918**	$	47,897
OTHER LIABILITIES				
Rabbi Trust Deferred Compensation Plan	**$**	**20,187**	$	21,600
Derivative Contracts				2,180
Other Accounts		**11,752**		8,399
	$	**31,939**	$	32,179

CABOT OIL & GAS CORPORATION

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

4. Debt and Credit Agreements

The Company's debt consisted of the following as of:

(In thousands)	December 31, 2011	2010
Long-Term Debt		
7.33% Weighted-Average Fixed Rate Notes	**$ 95,000**	$ 95,000
6.51% Weighted-Average Fixed Rate Notes	**425,000**	425,000
9.78% Notes	**67,000**	67,000
5.58% Weighted-Average Fixed Rate Notes	**175,000**	175,000
Credit Facility	**188,000**	213,000
	$ 950,000	$ 975,000

The Company has debt maturities of $75 million due in 2013 and $20 million in 2016. In addition, the revolving credit facility (credit facility) matures in 2015. No other tranches of debt are due within the next five years.

In June 2010, the Company amended the agreements governing its senior notes to amend the required asset coverage ratio (the present value of the Company's proved reserves plus working capital to debt) contained in the agreements. The amendments revised the calculation of present value of proved reserves to reflect specified pricing assumptions based on quoted futures prices in lieu of historical realized prices, reduced the limit on proved undeveloped reserves included in the calculation from 35% to 30%, and increased the required ratio from 1.50:1 to 1.75:1. The amendments also provided that for so long as a borrowing base calculation is required under the Company's credit facility, the calculated indebtedness may not exceed 115% of such borrowing base for this ratio. If such a borrowing base calculation is not required under the credit facility, the Company would no longer be subject to the asset coverage ratio under the agreements, but would instead be required to maintain a ratio of debt to consolidated EBITDAX (as defined) not to exceed 3.0 to 1.0. In conjunction with the amendments, the Company incurred $2.0 million of debt issuance costs which were capitalized and are being amortized over the term of the respective amended agreements in accordance with ASC 470-50, "Debt Modifications and Extinguishments."

7.33% Weighted-Average Fixed Rate Notes

In July 2001, the Company issued $170 million of Notes to a group of seven institutional investors in a private placement. The Notes have bullet maturities and were issued in three separate tranches as follows:

	Principal	Term	Maturity Date	Coupon
Tranche 1	$ 75,000,000	10-year	July 2011	7.26%
Tranche 2	$ 75,000,000	12-year	July 2013	7.36%
Tranche 3	$ 20,000,000	15-year	July 2016	7.46%

The 7.33% weighted-average fixed rate notes contain restrictions on the merger of the Company or any subsidiary with a third party other than under certain limited conditions. There are also various other restrictive covenants customarily found in such debt instruments. Those covenants include a

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CABOT OIL & GAS CORPORATION

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

4. Debt and Credit Agreements (Continued)

required asset coverage ratio (present value of proved reserves to debt and other liabilities) of at least 1.75 to 1.0 (as amended) and a minimum annual coverage ratio of operating cash flow to interest expense for the trailing four quarters of 2.8 to 1.0.

In December 2010, the Company repaid the $75.0 million outstanding of Tranche 1 prior to the due date. In connection with the early payment the Company was required to pay a make-whole premium of $2.8 million which is included in Interest Expense and Other in the Consolidated Statement of Operations.

6.51% Weighted-Average Fixed Rate Notes

In July 2008, the Company issued $425 million of senior unsecured fixed-rate notes to a group of 41 institutional investors in a private placement. The Notes have bullet maturities and were issued in three separate tranches as follows:

	Principal	Term	Maturity Date	Coupon
Tranche 1	$ 245,000,000	10-year	July 2018	6.44%
Tranche 2	$ 100,000,000	12-year	July 2020	6.54%
Tranche 3	$ 80,000,000	15-year	July 2023	6.69%

Interest on each series of the 6.51% weighted-average fixed rate notes is payable semi-annually. The Company may prepay all or any portion of the Notes of each series on any date at a price equal to the principal amount thereof plus accrued and unpaid interest plus a make-whole premium. The Notes contain restrictions on the merger of the Company with a third party other than under certain limited conditions. There are also various other restrictive covenants customarily found in such debt instruments. These covenants include a required asset coverage ratio (present value of proved reserves plus adjusted cash (as defined in the note purchase agreement) to debt and other liabilities) of at least 1.75 to 1.0 (as amended) and a minimum annual coverage ratio of operating cash flow to interest expense for the trailing four quarters of 2.8 to 1.0. The Notes also are subject to customary events of default. The Company is required to offer to prepay the Notes upon specified change in control events accompanied by a ratings decline below investment grade.

9.78% Notes

In December 2008, the Company issued $67 million aggregate principal amount of its 10-year 9.78% Series G Senior Notes to a group of four institutional investors in a private placement. Interest on the Notes is payable semi-annually. The Company may prepay all or any portion of the Notes on any date at a price equal to the principal amount thereof plus accrued and unpaid interest plus a make-whole premium. The other terms of the Notes are substantially similar to the terms of the 6.51% Weighted-Average Fixed Rate Notes.

CABOT OIL & GAS CORPORATION

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

4. Debt and Credit Agreements (Continued)

5.58% Weighted-Average Fixed Rate Notes

In December 2010, the Company issued $175 million of senior unsecured fixed-rate notes to a group of eight institutional investors in a private placement. The Notes have bullet maturities and were issued in three separate tranches as follows:

	Principal	Term	Maturity Date	Coupon
Tranche 1	$ 88,000,000	10-year	January 2021	5.42%
Tranche 2	$ 25,000,000	12-year	January 2023	5.59%
Tranche 3	$ 62,000,000	15-year	January 2026	5.80%

Interest on each series of the 5.58% weighted-average fixed rate notes is payable semi-annually. The Company may prepay all or any portion of the Notes of each series on any date at a price equal to the principal amount thereof plus accrued and unpaid interest plus a make-whole premium. The other terms of the Notes are substantially similar to the terms of the 6.51% Weighted-Average Fixed Rate Notes.

Revolving Credit Agreement

In September 2010, the Company amended and restated its revolving credit facility. The credit facility provides for an available credit line of $900 million and contains an accordion feature allowing the Company to increase the available credit line to $1.0 billion, if any one or more of the existing banks or new banks agree to provide such increased commitment amount. The amended facility provided for an initial $1.5 billion borrowing base and matures in September 2015. As of December 31, 2011, the Company's borrowing base was $1.7 billion.

In conjunction with entering into the September 2010 amended credit facility, the Company incurred $11.7 million of debt issuance costs, which were capitalized and will be amortized over the term of the amended credit facility. Approximately $6.3 million in unamortized costs associated with the original credit facility, as amended in June 2010, will be amortized over the term of the amended credit facility in accordance with ASC 470-50, "Debt Modifications and Extinguishments."

The credit facility is unsecured. The available credit line is subject to adjustment from time to time on the basis of (1) the projected present value (as determined by the banks based on the Company's reserve reports and engineering reports) of estimated future net cash flows from certain proved oil and gas reserves and certain other assets of the Company (the "Borrowing Base") and (2) the outstanding principal balance of the Company's senior notes. While the Company does not expect a reduction in the available credit line, in the event that it is adjusted below the outstanding level of borrowings in connection with scheduled redetermination or due to a termination of hedge positions, the Company has a period of six months to reduce its outstanding debt in equal monthly installments to the adjusted credit line available.

The Borrowing Base is redetermined annually under the terms of the credit facility on April 1. In addition, either the Company or the banks may request an interim redetermination twice a year in connection with certain acquisitions or sales of oil and gas properties. Effective April 1, 2011, the lenders under the Company's revolving credit facility approved an increase in the Company's borrowing base from $1.5 billion to $1.7 billion as part of the annual redetermination under the terms of the

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CABOT OIL & GAS CORPORATION

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

4. Debt and Credit Agreements (Continued)

credit facility. The Company's plan to sell certain oil and gas properties located in Colorado, Utah and Wyoming, triggered an interim redetermination of the Company's borrowing base, and the $1.7 billion borrowing base was reaffirmed by the lenders effective September 27, 2011.

Interest rates under the credit facility are based on Euro-Dollars (LIBOR) or Base Rate (Prime) indications, plus a margin. These associated margins increase if the total indebtedness under the credit facility and the Company's senior notes is greater than 25%, greater than 50%, greater than 75% or greater than 90% of the Borrowing Base, as shown below:

	Debt Percentage				
	<25%	**≥ 25% <50%**	**≥ 50% <75%**	**≥ 75% <90%**	**≥ 90%**
Eurodollar Margin	2.000%	2.250%	2.500%	2.750%	3.000%
Base Rate Margin	1.125%	1.375%	1.625%	1.875%	2.125%

The credit facility provides for a commitment fee on the unused available balance at annual rates of 0.50%.

The credit facility contains various customary restrictions, which include the following (with all calculations based on definitions contained in the agreement):

(a) Maintenance of a minimum annual coverage ratio of operating cash flow to interest expense for the trailing four quarters of 2.8 to 1.0.

(b) Maintenance of an asset coverage ratio of the present value of proved reserves plus working capital to debt of 1.75 to 1.0.

(c) Maintenance of a current ratio of 1.0 to 1.0.

(d) Prohibition on the merger or sale of all or substantially all of the Company's or any subsidiary's assets to a third party, except under certain limited conditions.

In addition, the credit facility includes a customary condition to the Company's borrowings under the facility that a material adverse change has not occurred with respect to the Company.

At December 31, 2011 and 2010, borrowings outstanding under the Company's credit facilities were $188.0 million and $213.0 million, respectively. In addition, the Company had $1.0 million letters of credit outstanding and availability under the credit facility of $711.0 million at December 31, 2011.

The Company's weighted-average effective interest rates for the credit facilities during the years ended December 31, 2011, 2010 and 2009 were approximately 4.1%, 3.8% and 4.0%, respectively. As of December 31, 2011 and 2010, the weighted-average interest rate on the Company's credit facility was approximately 4.9% and 3.1%, respectively.

5. Employee Benefit Plans

Pension Plan

Prior to its termination in 2010, the Company had a non-contributory, defined benefit pension plan for all full-time employees, referred to as the tax qualified defined benefit pension plan (qualified pension plan). Plan benefits were based primarily on years of service and salary level near retirement. During the existence of the plan, the Company complied with the Employee Retirement Income

CABOT OIL & GAS CORPORATION

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

5. Employee Benefit Plans (Continued)

Security Act (ERISA) of 1974 and Internal Revenue Code limitations when funding the plan. The Company also had an unfunded non-qualified supplemental pension plan to ensure payments to certain executive officers of amounts to which they would have been entitled under the provisions of the pension plan, but for limitations imposed by federal tax laws, referred to as the supplemental non-qualified pension arrangements (non-qualified pension plan).

Termination and Amendment of Qualified and Non-Qualified Pension Plans

On July 28, 2010, the Company notified its employees of its plan to terminate its qualified pension plan, with the plan and its related trust to be liquidated following appropriate filings with the Pension Benefit Guaranty Corporation and Internal Revenue Service, effective September 30, 2010. The Company then amended and restated the qualified pension plan to freeze benefit accruals, to provide for termination of the plan, to allow for an early retirement enhancement to be available to all active participants as of September 30, 2010 regardless of their age and years of service as of that date, and to make certain changes that were required or made desirable as a result of developments in the law. Because no further benefits will accrue under the qualified pension plan after September 30, 2010, the Company's related non-qualified pension plan was effectively frozen and no additional benefits were accrued under those arrangements after September 30, 2010.

Freezing the above plans resulted in a remeasurement of the pension obligations and plan assets as of July 28, 2010. In calculating the remeasurement at the time of the termination, management used a discount rate of 5.25% for the qualified pension plan and 4.5% for the non-qualified pension plan, which was consistent with the Company's methodology of determining the discount rate for these plans in prior periods. The discount rate was based on a yield curve based on high-quality corporate bonds that could be purchased to settle the pension obligation. Management determined the discount rate by matching this yield curve with the timing and amounts of the expected benefit payments for the Company's plans.

As a result of these changes to the Company's qualified and non-qualified pension plans, the Company revised its amortization period for prior service costs and actuarial losses based upon the anticipated final distribution of benefits from each plan. Prior service costs established in each plan prior to freeze were fully recognized in the third quarter of 2010 as a result of the plan freeze.

On December 15, 2011, the Company contributed $5.6 million to its non-qualified pension plan to fund the final distribution of benefits. As of December 31, 2011, the benefit obligations associated with the non-qualified pension plan were fully satisfied.

Obligations and Funded Status

The funded status represents the difference between the projected benefit obligation of the Company's qualified and non-qualified pension plans and the fair value of the qualified pension plan's assets at December 31.

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CABOT OIL & GAS CORPORATION

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

5. Employee Benefit Plans (Continued)

The change in the combined projected benefit obligation of the Company's qualified and non-qualified pension plans and the change in the Company's qualified pension plan assets at fair value are as follows:

	Year Ended December 31,		
(In thousands)	**2011[1]**	**2010**	**2009**
Change in Benefit Obligation			
Benefit Obligation at Beginning of Year	**$ 63,872**	$ 75,092	$ 63,008
Service Cost		2,774	3,443
Interest Cost	**2,826**	3,700	3,712
Actuarial Loss	**11,835**	9,265	6,262
Plan Termination and Amendment		(12,331)	
Benefits Paid	**(10,831)**	(14,628)	(1,333)
Annuities Paid	**(18,084)**		
Benefit Obligation at End of Year	**49,618**	63,872	75,092
Change in Plan Assets			
Fair Value of Plan Assets at Beginning of Year	**60,078**	53,180	34,295
Actual Return on Plan Assets	**(291)**	7,095	10,903
Employer Contributions	**14,332**	15,416	10,136
Benefits Paid	**(10,831)**	(14,628)	(1,333)
Annuities Purchased	**(18,084)**		
Expenses Paid	**(656)**	(985)	(821)
Fair Value of Plan Assets at End of Year	**44,548**	60,078	53,180
Funded Status at End of Year	**$ (5,070)**	$ (3,794)	$ (21,912)

(1) *On December 15, 2011, the Company made a final distribution of benefits from the non-qualified pension plan.*

Amounts Recognized in the Balance Sheet

Amounts recognized in the balance sheet consist of the following:

	December 31,		
(In thousands)	**2011**	**2010**	**2009**
Current Liabilities	**$ 5,070**	$ 603	$ 488
Long-Term Liabilities		3,191	21,424
	$ 5,070	$ 3,794	$ 21,912

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CABOT OIL & GAS CORPORATION

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

5. Employee Benefit Plans (Continued)

Amounts Recognized in Accumulated Other Comprehensive Income

Amounts recognized in accumulated other comprehensive income consist of the following:

	December 31,		
(In thousands)	**2011**	**2010**	**2009**
Prior Service Cost	**$ 221**	$ 1,267	$ 92
Net Actuarial Loss	**13,082**	12,248	32,061
	$ 13,303	$ 13,515	$ 32,153

Information for Pension Plans with an Accumulated Benefit Obligation in Excess of Plan Assets

	December 31,		
(In thousands)	**2011**	**2010**	**2009**
Projected Benefit Obligation	**$ 49,618**	$ 63,872	$ 75,092
Accumulated Benefit Obligation	**$ 49,618**	$ 63,872	$ 61,822
Fair Value of Plan Assets	**$ 44,548**	$ 60,078	$ 53,180

Components of Net Periodic Benefit Cost and Other Amounts Recognized in Other Comprehensive Income Combined Qualified and Non-Qualified Pension Plans

	Year Ended December 31,		
(In thousands)	**2011[1]**	**2010**	**2009**
Components of Net Periodic Benefit Cost			
Current Year Service Cost	**$**	$ 2,774	$ 3,443
Interest Cost	**2,826**	3,700	3,712
Expected Return on Plan Assets	**(4,103)**	(4,260)	(2,685)
Amortization of Prior Service Cost	**1,046**	572	51
Amortization of Net Loss	**10,527**	8,705	3,177
Plan Termination and Amendment		423	
Settlement	**5,523**	4,021	
Net Periodic Pension Cost	**$ 15,819**	$ 15,935	$ 7,698
Other Changes in Qualified Plan Assets and Benefit Obligations Recognized in Other Comprehensive Income			
Net (Gain)/Loss	**$ 16,884**	$ (4,523)	$ (1,135)
Amortization of Net Loss	**(10,527)**	(8,705)	(3,335)
Amortization of Prior Service Cost	**(1,046)**	(572)	
Effect of Plan Termination and Amendment		(816)	
Settlement	**(5,523)**	(4,021)	
Total Recognized in Other Comprehensive Income	**$ (212)**	$ (18,637)	$ (4,470)
Total Recognized in Net Periodic Benefit Cost and Other Comprehensive Income	**$ 15,607**	$ (2,702)	$ 3,228

(1)

On December 15, 2011, the Company made a final distribution of benefits from the non-qualified pension plan.

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CABOT OIL & GAS CORPORATION

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

5. Employee Benefit Plans (Continued)

The estimated prior service cost and net actuarial loss for the qualified pension plan that will be amortized from accumulated other comprehensive income into net periodic benefit cost over the next fiscal year are $0.2 million and $13.1 million, respectively.

Assumptions

Weighted-average assumptions used to determine projected pension benefit obligations were as follows:

	December 31,		
	2011	**2010**	**2009**
Discount Rate	**3.75%**	5.25%	5.75%
Rate of Compensation Increase			4.00%

Weighted-average assumptions used to determine net periodic pension costs are as follows:

	December 31,		
	2011	**2010**	**2009**
Discount Rate (January 1 - December 31)(1)	**4.50%**		5.75%
Discount Rate (January 1 - July 31)(2)	**5.25%**	5.25%	
Discount Rate (August 1 - December 31)(2)	**4.75%**	4.80%	
Expected Long-Term Return on Plan Assets	**8.00%**	8.00%	8.00%
Rate of Compensation Increase			4.00%

(1) *Represents the discount rate used to determine the projected benefit costs for qualified and non-qualified pension plans for 2009 and the non-qualified plan for 2011.*

(2) *Represents the discount rate used to determine the net periodic pension costs for the qualified plan for 2011 and 2010 and the non-qualified pension plan for 2010. For the qualified plan in 2011, a 5.25% discount rate was used from January 1, 2011 through July 31, 2011; due to a remeasurement triggered by settlements that occurred during the year, the discount rate was adjusted to 4.75% for the remainder of 2011. For both the qualified and non-qualified plans in 2010, a discount rate of 5.25% was used from January 1, 2010 through July 31, 2010. Due to the plan termination and amendments that were effective in July 2010, the discount rate was adjusted for determining the net periodic pension costs for the remainder of 2010 to 4.80%.*

The Company establishes the long-term expected rate of return by developing a forward looking long-term expected rate of return assumption for each asset class, taking into account factors such as the expected real return for the specific asset class and inflation. One of the plan objectives is that performance of the equity portion of the pension plan exceeds the Standard and Poors' 500 Index over the long-term. The Company also seeks to achieve a minimum five percent annual real rate of return (above the rate of inflation) on the total portfolio over the long-term. In the Company's pension calculations, the Company has used 8% as the expected long-term return on plan assets for 2011, 2010 and 2009. In order to derive this return, a Monte Carlo simulation was run using 5,000 simulations based upon the Company's actual asset allocation. This model uses historical data for the period of

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CABOT OIL & GAS CORPORATION

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

5. Employee Benefit Plans (Continued)

1926-2007 for stocks, bonds and cash to determine the best estimate range of future returns. The median rate of return, or return that the Company expects to achieve over 50% of the time, is approximately 9%. The Company expects to achieve at a minimum approximately 7% annual real rate of return on the total portfolio over the long-term at least 75% of the time. The Company believes that the 8% chosen is a reasonable estimate based on its actual results.

Plan Assets

The Company's pension plan assets were accounted for at fair value and are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Each portfolio uses independent pricing services approved by the Trustee to value the Company's investments. All common/collective trust funds are managed by the Trustee. Refer to Note 13 for more information and a description of the fair value hierarchy.

The Company's investments in equity securities for which market quotations are readily available are valued at the last reported sale price or official closing price as reported by an independent pricing service on the primary market or exchange on which they are traded.

The Company's investment in debt securities are valued based on quotations received from dealers who transact in markets with such securities or by independent pricing services. For corporate bonds, bank notes, floating rate loans, foreign government and government agency obligations, municipal securities, preferred securities, supranational obligations, U.S. government and government agency obligations pricing services generally utilize matrix pricing which considers yield or price of bonds of comparable quality, coupon, maturity and type as well as dealer supplied prices.

The fair value of the plan assets of the Company's qualified pension plan at December 31, 2011 and 2010 by asset category are as follows:

(In thousands)	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance as of December 31, 2011
Asset Category				
Cash	$ 1,093	$	$	**$ 1,093**
Equity securities:				
Domestic:				
Large-cap		13,036		**13,036**
Small-cap		2,270		**2,270**
Emerging Markets		1,321		**1,321**
Growth		2,685		**2,685**
International:				
Diversified		7,598		**7,598**
Small-cap		895		**895**
Debt securities		15,650		**15,650**
	$ 1,093	$ 43,455	$	**$ 44,548**

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CABOT OIL & GAS CORPORATION

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

5. Employee Benefit Plans (Continued)

(In thousands)	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance as of December 31, 2010
Asset Category				
Cash	$ 1,201	$	$	$ 1,201
Equity securities:				
Domestic:				
Large-cap		17,578		17,578
Small-cap		3,072		3,072
Emerging Markets		1,817		1,817
Growth		3,623		3,623
International:				
Diversified		10,204		10,204
Small-cap		1,232		1,232
Debt securities		21,351		21,351
	$ 1,201	$ 58,877	$	$ 60,078

The Company's investment strategy for the pension benefit plan assets is to remain fully invested in the market until the final determination for the plan termination is complete. The Company will continue to target a portfolio of assets utilizing equity securities, debt securities and cash equivalents that are within a range of approximately 50% to 80% for equity securities and approximately 20% to 40% for fixed income securities.

Cash Flows

Employer Contributions / Estimated Future Benefit Payments

The funding levels of the pension and postretirement benefit plans (described below) are in compliance with standards set by applicable law or regulation. The Company did not have any required minimum funding obligations for its qualified pension plan in 2011; however, it chose to fund $7.0 million into the qualified pension plan. In 2012, the Company does not have any required minimum funding obligations for the qualified plan; however, the Company expects to make a final distribution of benefits from the qualified pension plan in the first half of 2012. During 2011, the Company contributed $7.3 million to its non-qualified pension plan.

Postretirement Benefits Other than Pensions

The Company provides certain health care benefits for retired employees, including their spouses, eligible dependents and surviving spouses (retirees). These benefits are commonly called postretirement benefits. The health care plans are contributory, with participants' contributions adjusted annually. Most employees become eligible for these benefits if they meet certain age and service requirements at retirement. The Company was providing postretirement benefits to 275 retirees and their dependents at the end of 2011 and 257 retirees and their dependents at the end of 2010.

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CABOT OIL & GAS CORPORATION

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

5. Employee Benefit Plans (Continued)

Obligations and Funded Status

The funded status represents the difference between the accumulated benefit obligation of the Company's postretirement plan and the fair value of plan assets at December 31. The postretirement plan does not have any plan assets; therefore, the funded status is equal to the amount of the December 31 accumulated benefit obligation.

The change in the Company's postretirement benefit obligation is as follows:

	Year Ended December 31,		
(In thousands)	**2011**	**2010**	**2009**
Change in Benefit Obligation			
Benefit Obligation at Beginning of Year	**$ 31,947**	$ 34,392	$ 26,888
Service Cost	**1,403**	1,265	1,279
Interest Cost	**1,717**	1,696	1,594
Actuarial (Gain) / Loss	**6,015**	(4,415)	5,917
Benefits Paid	**(1,113)**	(991)	(1,286)
Benefit Obligation at End of Year	**$ 39,969**	$ 31,947	$ 34,392
Change in Plan Assets			
Fair Value of Plan Assets at End of Year			
Funded Status at End of Year	**$ (39,969)**	$ (31,947)	$ (34,392)

Amounts Recognized in the Balance Sheet

Amounts recognized in the balance sheet consist of the following:

	December 31,		
(In thousands)	**2011**	**2010**	**2009**
Current Liabilities	**$ 1,261**	$ 1,085	$ 981
Long-Term Liabilities	**38,708**	30,862	33,411
	$ 39,969	$ 31,947	$ 34,392

Amounts Recognized in Accumulated Other Comprehensive Income

Amounts recognized in accumulated other comprehensive income consist of the following:

	December 31,		
(In thousands)	**2011**	**2010**	**2009**
Transition Obligation	**$**	$ 632	$ 1,263
Net Actuarial Loss	**14,166**	8,408	13,455
	$ 14,166	$ 9,040	$ 14,718

CABOT OIL & GAS CORPORATION

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

5. Employee Benefit Plans (Continued)

The estimated net loss for the defined benefit postretirement plan that will be amortized from accumulated other comprehensive income into net periodic postretirement cost over the next fiscal year is $1.1 million.

Components of Net Periodic Benefit Cost and Other Amounts Recognized in Other Comprehensive Income

	Year Ended December 31,		
(In thousands)	**2011**	**2010**	**2009**
Components of Net Periodic Postretirement Benefit Cost			
Current Year Service Cost	**$ 1,403**	$ 1,265	$ 1,279
Interest Cost	**1,717**	1,696	1,594
Amortization of Prior Service Cost			666
Amortization of Net Obligation at Transition	**632**	632	632
Amortization of Net Loss	**448**	631	676
Net Periodic Postretirement Cost	**$ 4,200**	$ 4,224	$ 4,847
Other Changes in Benefit Obligations Recognized in Other Comprehensive Income			
Net (Gain) / Loss	**$ 6,015**	$ (4,415)	$ 5,917
Amortization of Prior Service Cost			(666)
Amortization of Net Obligation at Transition	**(632)**	(632)	(632)
Amortization of Net Loss	**(448)**	(631)	(676)
Total Recognized in Other Comprehensive Income	**4,935**	(5,678)	3,943
Total Recognized in Net Periodic Benefit Cost and Other Comprehensive Income	**$ 9,135**	$ (1,454)	$ 8,790

Assumptions

Assumptions used to determine projected postretirement benefit obligations and postretirement costs are as follows:

	December 31,		
	2011	**2010**	**2009**
Discount Rate[(1)]	**4.25%**	5.75%	5.75%
Health Care Cost Trend Rate for Medical Benefits Assumed for Next Year	**8.00%**	9.00%	10.00%
Rate to which the cost trend rate is assumed to decline (the Ultimate Trend Rate)	**5.00%**	5.00%	5.00%
Year that the rate reaches the Ultimate Trend Rate	**2015**	2015	2015

(1) *Represents the year end rates used to determine the projected benefit obligation. To compute postretirement cost in 2011, 2010 and 2009, respectively, the beginning of year discount rates of 4.25%, 5.75% and 5.75% were used.*

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CABOT OIL & GAS CORPORATION

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

5. Employee Benefit Plans (Continued)

Coverage provided to participants age 65 and older is under a fully-insured arrangement. The Company subsidy is limited to 60% of the expected annual fully-insured premium for participants age 65 and older. For all participants under age 65, the Company subsidy for all retiree medical and prescription drug benefits, beginning January 1, 2006, was limited to an aggregate annual amount not to exceed $648,000. This limit increases by 3.5% annually thereafter. The Company prepaid the life insurance premiums for all retirees retiring before January 1, 2006 eliminating all future premiums for retiree life insurance. A life insurance product is offered to employees allowing employees to continue coverage into retirement by paying the premiums directly to the life insurance provider.

Assumed health care cost trend rates may have a significant effect on the amounts reported for the health care plans. A one-percentage-point change in assumed health care cost trend rates would have the following effects:

(In thousands)	1-Percentage-Point Increase	1-Percentage-Point Decrease
Effect on total of service and interest cost	$ 642	$ (355)
Effect on postretirement benefit obligation	6,404	(5,207)

Cash Flows

Contributions

The Company expects to contribute approximately $1.3 million to the postretirement benefit plan in 2012.

Estimated Future Benefit Payments

The following estimated benefit payments under the Company's postretirement plans, which reflect expected future service, as appropriate, are expected to be paid as follows:

(In thousands)	
2012	1,287
2013	1,445
2014	1,679
2015	1,807
2016	1,920
Years 2017 - 2021	12,367

Savings Investment Plan

The Company has a Savings Investment Plan (SIP), which is a defined contribution plan. The Company matches a portion of employees' contributions in cash. Participation in the SIP is voluntary, and all regular employees of the Company are eligible to participate. The Company made contributions of $2.0 million, $2.2 million and $2.2 million in 2011, 2010 and 2009, respectively, which are included in General and Administrative expense in the Consolidated Statement of Operations. The Company matches employee contributions dollar-for-dollar on the first six percent of an employee's pretax earnings. The Company's common stock is an investment option within the SIP.

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CABOT OIL & GAS CORPORATION

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

5. Employee Benefit Plans (Continued)

In July 2010, the Company amended the SIP to provide for discretionary profit sharing contributions upon termination of the qualified pension plan effective September 30, 2010. The Company presently makes a discretionary profit-sharing contribution to this plan in an amount equal to 9% of an eligible plan participant's salary and bonus. The Company charged to expense plan contributions of $3.6 million and $0.8 million in 2011 and 2010, respectively, which are included in General and Administrative expense in the Consolidated Statement of Operations.

Deferred Compensation Plan

In 1998, the Company established a Deferred Compensation Plan which was available to officers of the Company and acts as a supplement to the SIP. The Internal Revenue Code does not cap the amount of compensation that may be taken into account for purposes of determining contributions to the Deferred Compensation Plan and does not impose limitations on the amount of contributions to the Deferred Compensation Plan. Effective October 1, 2010, the Company amended the Deferred Compensation Plan to broaden the group of eligible employees who participate in the plan beyond the officers of the Company. Under this amendment, the Company may designate any member of the Company's management group as a participant in the Deferred Compensation Plan and may further designate whether such a participant is eligible to make deferral elections from their compensation. At the present time, the Company anticipates making such a contribution to the Deferred Compensation Plan on behalf of a participant in the event that Internal Revenue Code limitations cause a participant to receive less than the full Company matching contribution under the SIP. The Deferred Compensation Plan was also amended to provide that the Company would credit the accounts of participants who had entered into supplemental employee retirement plan agreements with the Company in an amount equal to which such participant would have been entitled under the terms of the supplemental employee retirement plan agreement in effect between the Company and the participant as of September 29, 2010, if the participant had terminated employment on September 30, 2010. This amendment also placed restrictions on the payment of these amounts in order to comply with Section 409A of the Internal Revenue Code. Effective January 1, 2011, the Company amended and restated the Deferred Compensation Plan to incorporate prior plan amendments and to provide for Company contributions that may not be made to the Company's tax-qualified Savings Investment Plan as a result of limitations imposed by the Internal Revenue Code.

The assets of the Deferred Compensation Plan are held in a rabbi trust and are subject to additional risk of loss in the event of bankruptcy or insolvency of the Company.

The participants direct the deemed investment of amounts credited to their accounts under the Deferred Compensation Plan. The trust assets are invested in either mutual funds that cover the investment spectrum from equity to money market, or may include holdings of the Company's common stock, which is funded by the issuance of shares to the trust. The mutual funds are publicly traded and have market prices that are readily available. Settlement payments are made to participants in cash, either in a lump sum or in periodic installments. The market value of the trust assets, excluding the Company's common stock, was $10.8 million and $15.8 million at December 31, 2011 and 2010, respectively, and is included in Other Assets in the Consolidated Balance Sheet. Related liabilities, including the Company's common stock, totaled $20.2 million and $21.6 million at December 31, 2011 and 2010, respectively, and are included in Other Liabilities in the Consolidated Balance Sheet. With the exception of the Company's common stock, there is no impact on earnings or earnings per share from the changes in market value of the deferred compensation plan assets because the changes in

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CABOT OIL & GAS CORPORATION

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

5. Employee Benefit Plans (Continued)

market value of the trust assets are offset completely by changes in the value of the liability, which represents trust assets belonging to plan participants.

The Company's common stock held in the rabbi trust is recorded at the market value on the date of deferral, which totaled $4.9 million and $6.6 million at December 31, 2011 and 2010, respectively and is included in Additional Paid-in Capital in Stockholders' Equity in the Consolidated Balance Sheet. As of December 31, 2011, 267,087 shares of the Company's stock representing vested performance share awards were deferred into the rabbi trust. During 2011, a decrease to the rabbi trust deferred compensation liability of $1.4 million was recognized, representing a decrease of $4.9 million related to a decrease in value of investments, excluding the Company's stock, coupled with a $0.8 million reduction in the liability due to shares that were sold out of the rabbi trust, partially offset by a $4.3 million increase based on the increase in the closing price of the Company's stock December 31, 2010 to December 31, 2011. The Company recognized $5.3 million in General and Administrative expense in the Consolidated Statement of Operations representing the increase in the closing price of the Company's shares held in the trust and also due to the sale of shares in the Company's stock. The Company's common stock issued to the trust is not considered outstanding for purposes of calculating basic earnings per share, but is considered a common stock equivalent in the calculation of diluted earnings per share.

The Company charged to expense plan contributions of $522,807, $109,196 and $0 in 2011, 2010 and 2009, respectively, which are included in General and Administrative expense in the Consolidated Statement of Operations.

6. Income Taxes

Income tax expense is summarized as follows:

	Year Ended December 31,		
(In thousands)	**2011**	**2010**	**2009**
Current			
Federal	**$ 39,749**	$ 29,879	$ (26,323)
State	**(1,714)**	3,424	(545)
Total	**38,035**	33,303	(26,868)
Deferred			
Federal	**46,599**	37,981	100,896
State	**28,145**	23,828	919
Total	**74,744**	61,809	101,815
Total Income Tax Expense	**$ 112,779**	$ 95,112	$ 74,947

CABOT OIL & GAS CORPORATION

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

6. Income Taxes (Continued)

Total income taxes were different than the amounts computed by applying the statutory federal income tax rate as follows:

	Year Ended December 31,		
(Dollars in thousands)	**2011**	**2010**	**2009**
Statutory Federal Income Tax Rate	**35%**	35%	35 %
Computed "Expected" Federal Income Tax	**$ 82,316**	$ 69,475	$ 78,153
State Income Tax, Net of Federal Income Tax Benefit	**8,989**	6,638	4,476
Deferred Tax Adjustment Related to Change in Overall State Tax Rate	**19,068**	18,973	(3,925)
Sale of Foreign Assets			(1,656)
Other, Net	**2,406**	26	(2,101)
Total Income Tax Expense	**$ 112,779**	$ 95,112	$ 74,947

The tax effects of temporary differences that resulted in significant portions of the deferred tax liabilities and deferred tax assets were as follows:

	December 31,	
(In thousands)	**2011**	**2010**
Deferred Tax Liabilities		
Property, Plant and Equipment	**$ 1,068,762**	$ 925,397
Hedging Liabilities / Receivables	**68,670**	6,419
Prepaid Expenses and Other	**9,261**	6,654
Total	**1,146,693**	938,470
Deferred Tax Assets		
Alternative Minimum Tax Credit	**101,290**	62,105
Net Operating Loss	**113,496**	95,102
Foreign Tax Credits	**4,685**	6,354
Pension and Other Post-Retirement Benefits	**19,892**	13,342
Items Accrued for Financial Reporting Purposes and Other	**49,606**	46,871
Total	**288,969**	223,774
Net Deferred Tax Liabilities	**$ 857,724**	$ 714,696

As of December 31, 2011, the Company had alternative minimum tax credit carryforwards of $101.3 million which do not expire and can be used to offset regular income taxes in future years to the extent that regular income taxes exceed the alternative minimum tax in any such year. The Company also had net operating loss carryforwards of $291.8 million and $312.7 million for federal and state reporting purposes, respectively, the majority of which will expire between 2016 and 2031. It is expected that these deferred tax benefits will be utilized prior to their expiration.

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CABOT OIL & GAS CORPORATION

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

6. Income Taxes (Continued)

Uncertain Tax Positions

A reconciliation of the beginning and ending amount of unrecognized tax benefits is as follows:

		Year Ended December 31,	
(In thousands)	**2011**	**2010**	**2009**
Unrecognized tax benefit balance at beginning of year	**$**	$ 500	$ 500
Additions based on tax provisions related to the current year			
Additions for tax positions of prior years			
Reductions for tax positions of prior years		(500)	
Settlements			
Unrecognized tax benefit balance at end of year	**$**	$	$ 500

During 2010, unrecognized tax benefits were reduced by $0.5 million as a result of the completion of the Internal Revenue Service (IRS) Joint Committee on Taxation review of the 2005-2008 tax years that were under audit by the IRS. This reduction did not materially affect the effective tax rate. As of December 31, 2011 and 2010, the Company did not have any uncertain tax positions reported in the Consolidated Balance Sheet.

The Company files income tax returns in the U.S. federal jurisdiction, various states and other jurisdictions. The Company is no longer subject to examinations by state authorities before 2005. The Company is not currently under examination by the IRS.

7. Commitments and Contingencies

Gas Transportation Agreements

The Company has entered into gas transportation agreements with various pipelines with initial terms ranging from four to 25 years. Under certain of these agreements, the Company is obligated to transport minimum daily natural gas volumes, or pay for any deficiencies at a specified rate. The Company is also obligated under certain of these arrangements to pay a demand charge for firm capacity rights on pipeline systems regardless of the amount of pipeline capacity utilized by the Company. In most cases, the Company's production commitment to these pipelines is expected to exceed minimum daily volumes provided in the agreements. If the Company does not utilize the capacity, it can release it to others, thus reducing its potential liability.

Future obligations under gas transportation agreements as of December 31, 2011 are as follows:

(In thousands)	
2012	84,285
2013	115,221
2014	122,106
2015	122,184
2016	122,542
Thereafter	1,286,991
	$ 1,853,329

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CABOT OIL & GAS CORPORATION

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

7. Commitments and Contingencies (Continued)

Drilling Rig Commitments

During 2011, the Company entered into two drilling rig commitments ranging from two to three years for its capital program in the Marcellus Shale in northeast Pennsylvania. The drilling rig commitments commenced in the fourth quarter of 2011. The future minimum commitments under these agreements as of December 31, 2011 are $19.8 million in 2012, $18.1 million in 2013 and $8.0 million in 2014.

Hydraulic Fracturing Services Commitments

During 2011, the Company entered into a thirteen month hydraulic fracturing services commitment in the Marcellus Shale in northeast Pennsylvania, which commenced in the fourth quarter of 2011. The future minimum commitments under the agreement as of December 31, 2011 are $82.2 million in 2012.

Lease Commitments

The Company leases certain transportation vehicles, warehouse facilities, office space, and machinery and equipment under cancelable and non-cancelable leases. Rent expense under these arrangements totaled $13.6 million, $18.3 million and $17.4 million for the years ended December 31, 2011, 2010 and 2009, respectively.

Future minimum rental commitments under non-cancelable leases in effect at December 31, 2011 are as follows:

(In thousands)	
2012	5,656
2013	5,311
2014	4,591
2015	2,876
2016	201
Thereafter	
	$ 18,635

Legal Matters

Preferential Purchase Right Litigation

In September 2005, the Company and Linn Energy, LLC were sued by Power Gas Marketing & Transmission, Inc. in the Court of Common Pleas of Indiana County, Pennsylvania. The lawsuit seeks unspecified damages arising out of the Company's 2003 sale of oil and gas properties located in Indiana County, Pennsylvania, to Linn Energy, LLC. The plaintiff alleges breach of a preferential purchase right regarding those properties contained in a 1969 joint operating agreement, to which the plaintiff was a party. The Company initially obtained judgment as a matter of law as to all claims in a decision by the trial court dated February 2007. Plaintiff appealed the ruling to the Pennsylvania Superior Court, where the ruling in favor of the Company was reversed and remanded to the trial court in March 2008. The Company appealed the Superior Court ruling to the Pennsylvania Supreme Court, but in December 2008 that Court declined to review. Effective July 2008, Linn Energy, LLC sold the subject properties

CABOT OIL & GAS CORPORATION

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

7. Commitments and Contingencies (Continued)

to XTO Energy, Inc., giving rise to a second lawsuit for unspecified damages filed in September 2009 by EXCO North Coast Energy, Inc., as successor in interest to Power Gas Marketing & Transmission, Inc., against the Company, Linn Energy, LLC and XTO Energy, Inc. The second lawsuit has been consolidated into the first lawsuit. A bench trial on the merits, should one be necessary, has been set for early March 2012.

The Company believes that the plaintiff's claims lack merit and does not consider a loss related to this matter to be probable; however, due to the inherent uncertainties of litigation a loss is possible. In the event that the Company is found liable, the potential loss is currently estimated to be less than $15 million.

Other

The Company is also a defendant in various other legal proceedings arising in the normal course of business. All known liabilities are accrued based on management's best estimate of the potential loss. While the outcome and impact of these legal proceedings on the Company cannot be predicted with certainty, management believes that the resolution of these proceedings will not have a material effect on the Company's financial position or cash flow; however, operating results could be significantly impacted in reporting periods in which such matters are resolved.

Contingency Reserves

When deemed necessary, the Company establishes reserves for certain legal proceedings. The establishment of a reserve is based on an estimation process that includes the advice of legal counsel and subjective judgment of management. While management believes these reserves to be adequate, it is reasonably possible that the Company could incur additional losses with respect to those matters in which reserves have been established. The Company believes that any such amount above the amounts accrued is not material to the Consolidated Financial Statements. Future changes in facts and circumstances could result in the actual liability exceeding the estimated ranges of loss and amounts accrued.

Environmental Matters

Pennsylvania Department of Environmental Protection

On November 4, 2009, the Company and the Pennsylvania Department of Environmental Protection (PaDEP) executed a consent order (Consent Order) addressing a number of environmental issues identified in 2008 and 2009, including alleged releases of drilling mud and other substances, alleged record keeping violations at various wells and alleged natural gas contamination of 13 water supplies in Susquehanna County, Pennsylvania. As part of the settlement, the Company paid an aggregate $120,000 civil penalty with respect to the matters addressed by the Consent Order, which were consolidated at the request of the PaDEP.

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CABOT OIL & GAS CORPORATION

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

7. Commitments and Contingencies (Continued)

On April 15, 2010, the Company and the PaDEP executed a modified Consent Order (First Modified Consent Order). The First Modified Consent Order provided that the Company would make available a permanent source of potable water to 14 households, most of which the Company had already been supplying with water. The First Modified Consent Order included the following conditions: (i) the Company would plug and abandon three vertical natural gas wells and would undertake certain remedial measures on a fourth well in a nine square mile area in Susquehanna County; (ii) the Company would complete these actions prior to new natural gas well drilling permits being issued for drilling in Pennsylvania, and prior to initiating hydraulic fracturing of seven wells already drilled in the area of concern; and (iii) the Company would also postpone drilling of new natural gas wells in the area of concern until certain terms of the consent orders were fulfilled. In addition, the First Modified Consent Order included a condition that the Company would take certain other actions if requested by the PaDEP and agreed to by the Company, which could include the plugging and abandonment of up to 10 additional wells. As part of the settlement, the Company paid a $240,000 civil penalty and the First Modified Consent Order included a provision that the Company would pay an additional $30,000 per month until certain terms under the First Modified Consent Order were satisfied.

On July 19, 2010, the Company and the PaDEP executed a Second Modification to Consent Order (Second Modified Consent Order) acknowledging that the Company plugged and abandoned the three vertical natural gas wells and completed work on the fourth natural gas well to the PaDEP's satisfaction. As a result, the PaDEP agreed to commence the processing and issuance of new well drilling permits outside the area of concern so long as the Company continued to provide temporary potable water and offered to provide gas/water separators to 14 households. No penalties were assessed under the Second Modified Consent Order.

As outlined in the Second Modified Consent Order, the Company made offers to provide whole-house water treatment systems to 14 households. On August 5, 2010 the Company filed with the PaDEP its report, prepared by its experts, finding that the Company's natural gas well drilling and development activities were not the source of methane gas reported to be in the groundwater and water wells in the area of concern.

In a September 14, 2010 letter to the Company, the PaDEP rejected the Company's expert report and stated its determination that the Company's drilling activities continue to cause the unpermitted discharge of natural gas into the groundwater and continue to affect residential water supplies in the area of concern. The PaDEP directed the Company to plug or take remedial actions at the remaining 10 natural gas wells and to contact the PaDEP to discuss connecting the impacted water supplies into community public water systems.

In a September 28, 2010 reply letter to the PaDEP, the Company disagreed with the PaDEP's rejection of the Company's expert report, disagreed that the remaining 10 natural gas wells continue to impact groundwater and affect residential water supplies and disagreed that a community public water system is necessary or feasible. The Company believed that offering installation of a whole-house water treatment system to the 14 households constituted compliance with the Company's obligations under these consent orders. The Company also asserted its belief that the Consent Order, First Modified Consent Order and Second Modified Consent Order were unlawful and not legally binding or enforceable.

CABOT OIL & GAS CORPORATION

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

7. Commitments and Contingencies (Continued)

On December 15, 2010, the Company entered into a consent order and settlement agreement with the PaDEP (CO&SA), which according to its terms supersedes and/or replaces the Consent Order, the First Modified Consent Order and the Second Modified Consent Order. Under the CO&SA, among other things, the Company agreed to place a total of $4.2 million into escrow accounts for the benefit of each of the identified households, pay $500,000 to the PaDEP to reimburse the PaDEP for its costs, perform remedial measures for two natural gas wells in the area of concern, provide pressure, water quality and water well headspace data to the PaDEP and offer water treatment to the households. The CO&SA settled all outstanding issues and claims that are known and that could have been brought against the Company by the PaDEP relating to the natural gas wells in the affected area and the Consent Order, the First Modified Consent Order and the Second Modified Consent Order. It also allows the Company to seek to begin hydraulic fracturing and to commence drilling new wells in the affected areas after providing the PaDEP with certain data and information. Under the CO&SA, the Company has no obligation to connect the impacted water supplies to a community public water system.

On January 11, 2011, certain of the affected households appealed the CO&SA to the Pennsylvania Environmental Hearing Board (PEHB).

The Company is in continuing discussions with the PaDEP to address the results of the Company's natural gas well test data, water quality sampling and water well headspace screenings. The Company requested PaDEP approval to resume hydraulic fracturing and new natural gas well drilling operations in the affected area, along with a request to cease temporary water deliveries to the affected households. On October 18, 2011, the PaDEP concurred that temporary water deliveries to the property owners are no longer necessary.

On November 18, 2011, certain of the affected households appealed to the PEHB the PaDEP's October 18, 2011 determination that temporary water deliveries were no longer necessary to the property owners and on November 23, 2011 filed a Petition for Supersedeas in the appeal. On December 9, 2011, the PEHB denied the Petition for Supersedeas and consolidated the appeal of the CO&SA with the appeal of the October 18, 2011 determination. A hearing on the consolidated matter is expected to occur in 2012.

As of December 31, 2011, the Company has paid $1.3 million in settlement of fines and penalties sought or claimed by the PaDEP related to this matter, paid $2.0 million (through the escrow process) to seven of the affected households and accrued a $2.2 million settlement liability that represents the unpaid escrow balance, which is included in Other Liabilities in the Consolidated Balance Sheet.

United States Environmental Protection Agency

By letter dated January 6, 2012, the United States Environmental Protection Agency (EPA) sent a Required Submission of Information Dimock Township Drinking Water Contamination letter to the Company pursuant to the Comprehensive Environmental Response, Compensation, and Liability Act of 1980, as amended (CERCLA). The Required Submission of Information requests all documents, water sampling results and any other correspondence related to the Company's activities in the area of concern. The Company does not agree that the Submission of Information is required; however, the Company is providing information pursuant to the request.

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CABOT OIL & GAS CORPORATION

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

8. Asset Retirement Obligation

Activity related to the Company's asset retirement obligation during the year ended December 31, 2011 is as follows:

(In thousands)	
Carrying amount of asset retirement obligations at beginning of year	$ 72,311
Liabilities incurred	1,480
Liabilities settled	(1,236)
Liabilities divested	(12,110)
Accretion expense	3,344
Change in Estimate	(3,647)
Carrying amount of asset retirement obligations at end of year	**$ 60,142**

Accretion expense for the years ended December 31, 2011, 2010 and 2009 was $3.3 million, $1.9 million and $1.3 million, respectively.

9. Supplemental Cash Flow Information

Cash paid / (received) for interest and income taxes are as follows:

	Year Ended December 31,		
(In thousands)	**2011**	**2010**	**2009**
Interest	**$ 62,353**	$ 64,342	$ 56,301
Income Taxes	**65,352**	(1,050)	27,080

10. Capital Stock

Incentive Plans

Under the Company's 2004 Incentive Plan, incentive and non-statutory stock options, stock appreciation rights (SARs), stock awards, cash awards and performance awards may be granted to key employees, consultants and officers of the Company. Non-employee directors of the Company may be granted discretionary awards under the 2004 Incentive Plan consisting of stock options or stock awards. A total of 10,200,000 shares of common stock may be issued under the 2004 Incentive Plan. Under the 2004 Incentive Plan, no more than 3,600,000 shares may be used for stock awards that are not subject to the achievement of performance based goals, and no more than 6,000,000 shares may be issued pursuant to incentive stock options.

Stock Split

On January 3, 2012, the Board of Directors declared a 2-for-1 split of the Company's common stock in the form of a stock dividend. The stock dividend was distributed on January 25, 2012 to shareholders of record as of January 17, 2012. All common stock accounts and per share data have been retroactively adjusted to give effect to the 2-for-1 split of the Company's common stock.

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CABOT OIL & GAS CORPORATION

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

10. Capital Stock (Continued)

Treasury Stock

The Board of Directors has authorized a share repurchase program under which the Company may purchase shares of common stock in the open market or in negotiated transactions. The timing and amount of these stock purchases are determined at the discretion of management. The Company may use the repurchased shares to fund stock compensation programs presently in existence, or for other corporate purposes. All purchases executed to date have been through open market transactions. There is no expiration date associated with the authorization to repurchase securities of the Company.

During the year ended December 31, 2011, the Company did not repurchase any shares of common stock. Since the authorization date, the Company has repurchased 10,409,400 shares of the 20 million total shares authorized for a total cost of approximately $85.7 million. The repurchased shares were held as treasury stock with 10,005,000 shares having been subsequently retired. No treasury shares have been delivered or sold by the Company subsequent to the repurchase. As of December 31, 2011, 404,400 shares were held as treasury stock.

Dividend Restrictions

The Board of Directors of the Company determines the amount of future cash dividends, if any, to be declared and paid on the common stock depending on, among other things, the Company's financial condition, funds from operations, the level of its capital and exploration expenditures, and its future business prospects. None of the note or credit agreements in place have a restricted payment provision or other provision limiting dividends.

Expired Purchase Rights Plan

On January 21, 1991, the Board of Directors adopted the Preferred Stock Purchase Rights Plan and declared a dividend distribution of one right for each outstanding share of common stock. On December 8, 2000, the rights agreement for the plan was amended and restated to extend the term of the plan to 2010 and to make other changes. The rights plan expired on January 21, 2010. At December 31, 2010 there were no shares of Junior Preferred Stock issued or outstanding.

11. Stock-Based Compensation

Compensation expense charged against income for stock-based awards (including the supplemental employee incentive plan) for the years ended December 31, 2011, 2010 and 2009 was $39.5 million, $14.4 million and $25.1 million, respectively, and is included in General and Administrative expense in the Consolidated Statement of Operations.

For the year ended December 31, 2009, the Company realized a $13.8 million tax benefit related to the federal tax deduction in excess of book compensation cost for employee stock-based compensation for 2008. For regular federal income tax purposes, the Company was in a net operating loss position in 2008. As the Company carried back net operating losses concurrent with its 2008 tax return filing, the income tax benefit related to stock-based compensation was recorded in 2009. In accordance with ASC 718, the Company is able to recognize this tax benefit only to the extent it reduces the Company's income taxes payable.

There were no excess tax benefits recorded for the years ended December 31, 2011 and 2010 as the Company was in a net operating loss position for federal tax purposes. As of December 31, 2011,

CABOT OIL & GAS CORPORATION

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

11. Stock-Based Compensation (Continued)

the Company had cumulative unrecorded excess tax benefits for employee stock-based compensation of $5.2 million.

Restricted Stock Awards

Most restricted stock awards vest either at the end of a three year service period or on a graded-vesting basis at each anniversary date over a three or four year service period. For awards that vest at the end of the three year service period, expense is recognized ratably using a straight-line expensing approach over three years. Under the graded-vesting approach, the Company recognizes compensation cost ratably over the three or four year requisite service period, as applicable, for each separately vesting tranche as though the awards are, in substance, multiple awards. For all restricted stock awards, vesting is dependent upon the employees' continued service with the Company, with the exception of employment termination due to death, disability or retirement.

The fair value of restricted stock grants is based on the average of the high and low stock price on the grant date. The maximum contractual term is four years. In accordance with ASC 718, the Company accelerated the vesting period for retirement-eligible employees for purposes of recognizing compensation expense in accordance with the vesting provisions of the Company's stock-based compensation programs for awards issued after the adoption of ASC 718. The Company used an annual forfeiture rate of 7.0% for purposes of recognizing stock-based compensation expense for restricted stock awards. The annual forfeiture rates were based on approximately ten years of the Company's history for this type of award to various employee groups.

The following table is a summary of restricted stock award activity for the year ended December 31, 2011:

Restricted Stock Awards	Shares	Weighted-Average Grant Date Fair Value per Share	Weighted-Average Remaining Contractual Term (in years)	Aggregate Intrinsic Value (in thousands)[1]
Outstanding at December 31, 2010	264,326	$ 17.77		
Granted	19,600	27.66		
Vested	(14,732)	16.81		
Forfeited	(31,000)	17.60		
Outstanding at December 31, 2011	**238,194**	**$ 18.35**	**0.8**	**$ 9,039**

(1) *The aggregate intrinsic value of restricted stock awards is calculated by multiplying the closing market price of the Company's stock on December 30, 2011 by the number of non-vested restricted stock awards outstanding.*

As shown in the table above, there were 19,600 shares of restricted stock granted to employees during 2011 with a weighted-average grant date fair value per share of $27.66. During the year ended December 31, 2010, 47,600 shares of restricted stock were granted to employees with a weighted-average grant date fair value per share of $17.44. During the year ended December 31, 2009, 290,120 shares of restricted stock were granted to employees with a weighted-average grant date fair value per

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CABOT OIL & GAS CORPORATION

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

11. Stock-Based Compensation (Continued)

share of $17.48. The total fair value of shares vested during 2011, 2010 and 2009 was $0.2 million, $1.5 million and $1.2 million, respectively.

Compensation expense recorded for all restricted stock awards for the years ended December 31, 2011, 2010 and 2009 was $1.2 million, $1.8 million and $1.2 million, respectively. Unamortized expense as of December 31, 2011 for all outstanding restricted stock awards was $1.3 million and will be recognized over the next 0.8 years.

Restricted Stock Units

Restricted stock units are granted from time to time to non-employee directors of the Company. The fair value of these units is measured at the average of the high and low stock price on grant date and compensation expense is recorded immediately. These units immediately vest and are issued when the director ceases to be a director of the Company.

The following table is a summary of restricted stock unit activity for the year ended December 31, 2011:

Restricted Stock Units	**Units**	**Weighted-Average Grant Date Fair Value per Unit**	**Weighted-Average Remaining Contractual Term (in years)[(2)]**	**Aggregate Intrinsic Value (in thousands)[(1)]**
Outstanding at December 31, 2010	284,252	$ 14.68		
Granted and fully vested	59,402	20.88		
Issued				
Forfeited				
Outstanding at December 31, 2011	**343,654**	**$ 15.75**		**$ 13,042**

(1) *The intrinsic value of restricted stock units is calculated by multiplying the closing market price of the Company's stock on December 30, 2011 by the number of outstanding restricted stock units.*

(2) *Due to the immediate vesting of the units and the unknown term of each director, the weighted-average remaining contractual term in years has been omitted from the table above.*

As shown in the table above, 59,402 restricted stock units were granted with a weighted-average grant date fair value per share of $20.88 during 2011. During 2010, 53,922 restricted stock units were granted with a weighted-average grant date fair value per share of $20.04. During 2009, 66,300 restricted stock units were granted with a weighted-average grant date fair value per share of $11.32.

During the years ended December 31, 2011, 2010 and 2009, compensation cost recorded, which reflects the total fair value of these units, was $1.2 million, $1.1 million and $0.8 million, respectively.

Stock Options

Stock option awards are granted with an exercise price equal to the average of the high and low trading price of the Company's stock at the date of grant. During the years ended December 31, 2011, 2010 and 2009, there were no stock options granted. During 2011 and 2010 there was no compensation expense recorded. Compensation expense recorded for stock options for 2009 was less than $0.1 million. There was no unamortized expense as of December 31, 2011 for stock options.

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CABOT OIL & GAS CORPORATION

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

11. Stock-Based Compensation (Continued)

The following table is a summary of stock option activity for the years ended December 31, 2011, 2010 and 2009:

	2011		2010		2009	
Stock Options	**Shares**	**Weighted-Average Exercise Price**	**Shares**	**Weighted-Average Exercise Price**	**Shares**	**Weighted-Average Exercise Price**
Outstanding at Beginning of Year	**30,000**	**$ 11.90**	100,000	$ 11.90	121,000	$ 10.85
Granted						
Exercised	**(30,000)**	**11.90**	(70,000)	11.90	(21,000)	5.83
Forfeited or Expired						
Outstanding at December 31		**$**	30,000	$ 11.90	100,000	$ 11.90
Options Exercisable at December 31		**$**	30,000	$ 11.90	100,000	$ 11.90

The total intrinsic value of options exercised during the years ended December 31, 2011, 2010 and 2009 was $0.2 million, $0.5 million and $0.1 million, respectively.

Stock Appreciation Rights

Stock appreciation rights (SARs) allow the employee to receive any intrinsic value over the grant date market price that may result from the price appreciation on a set number of common shares during the contractual term of seven years. All of these awards have graded-vesting features and will vest over a service period of three years, with one-third of the award becoming exercisable each year on the anniversary date of the grant. The Company calculates the fair value using a Black-Scholes model.

The assumptions used in the Black-Scholes fair value calculation on the date of grant for SARs are as follows:

	Year Ended December 31,		
	2011	**2010**	**2009**
Weighted-Average Value per Stock Appreciation Rights			
Granted During the Period	**$ 9.47**	$ 9.48	$ 4.68
Assumptions			
Stock Price Volatility	**52.7%**	52.9%	50.5%
Risk Free Rate of Return	**2.3%**	2.4%	1.7%
Expected Dividend Yield	**0.3%**	0.3%	0.5%
Expected Term (in years)	**5.0**	5.0	4.5

The expected term was derived by reviewing minimum and maximum expected term outputs from the Black-Scholes model based on award type and employee type. This term represents the period of time that awards granted are expected to be outstanding. The stock price volatility was calculated using historical closing stock price data for the Company for the period associated with the expected term through the grant date of each award. The risk free rate of return percentages are based on the continuously compounded equivalent of the U.S. Treasury (Nominal 10) within the expected term as

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CABOT OIL & GAS CORPORATION

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

11. Stock-Based Compensation (Continued)

measured on the grant date. The expected dividend percentage assumes that the Company will continue to pay a consistent level of dividend each quarter.

The following table is a summary of SAR activity for the years ended December 31, 2011, 2010 and 2009:

	Year Ended December 31,					
	2011		2010		2009	
Stock Appreciation Rights	Shares	Weighted-Average Exercise Price	Shares	Weighted-Average Exercise Price	Shares	Weighted-Average Exercise Price
Outstanding at Beginning of Year	**1,471,300**	**$ 15.27**	1,346,200	$ 14.64	983,860	$ 16.13
Granted	**191,500**	**20.37**	159,100	20.27	443,560	11.32
Exercised	**(374,670)**	**15.22**	(34,000)	13.58	(40,732)	13.10
Forfeited or Expired					(40,488)	16.10
Outstanding at December 31[(1)]	**1,288,130**	**$ 16.04**	1,471,300	$ 15.27	1,346,200	$ 14.64
Exercisable at December 31[(2)]	**902,664**	**$ 15.14**	1,064,444	$ 14.82	708,504	$ 14.29

(1) *The intrinsic value of a SAR is the amount which the current market value of the underlying stock exceeds the exercise price of the SAR. The aggregate intrinsic value of SARs outstanding at December 31, 2011 was $28.2 million. The weighted-average remaining contractual term is 3.4 years.*

(2) *The aggregate intrinsic value of SARs exercisable at December 31, 2011 was $20.6 million. The weighted-average remaining contractual term is 2.5 years.*

During 2011, the Compensation Committee granted 191,500 SARs to employees at a weighted-average exercise price equal to the grant date market price of $20.37. Compensation expense recorded during the years ended December 31, 2011, 2010 and 2009 for all outstanding SARs was $2.1 million, $1.6 million and $1.8 million, respectively. In 2011, 2010 and 2009 there was $0.1 million, $0 and $0.7 million, related to the immediate expensing of shares granted to retirement-eligible employees, respectively. Unamortized expense as of December 31, 2011 for all outstanding SARs was $0.3 million. The weighted-average period over which this compensation will be recognized is approximately 2.0 years.

Performance Share Awards

During 2011, three types of performance share awards were granted to employees for a total of 789,514 performance shares, which included 604,122 performance share awards based on performance conditions measured against the Company's internal performance metrics and 185,392 performance share awards based on market conditions. The Company used an annual forfeiture rate assumption ranging from 0% to 7% for purposes of recognizing stock-based compensation expense for all performance share awards. The performance period for the awards granted in 2011 commenced on January 1, 2011 and ends on December 31, 2013.

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CABOT OIL & GAS CORPORATION

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

11. Stock-Based Compensation (Continued)

The performance awards based on internal metrics had a grant date per share value of $20.37, which is based on the average of the high and low stock price on the grant date. These awards represent the right to receive up to 100% of the award in shares of common stock.

Of the 604,122 performance awards based on internal metrics, 185,392 shares have a three-year graded performance period. For these shares, one-third of the shares are issued on each anniversary date following the date of grant, provided that the Company has $100 million or more of operating cash flow for the year preceding the vesting date. If the Company does not meet this metric for the applicable period, then the portion of the performance shares that would have been issued on that date will be forfeited. As of December 31, 2011, it is considered probable that this performance metric will be met.

For the remaining 418,730 performance awards based on internal metrics, the actual number of shares issued at the end of the performance period will be determined based on the Company's performance against three performance criteria set by the Company's Compensation Committee. An employee will earn one-third of the award granted for each internal performance metric that the Company meets at the end of the performance period. These performance criteria measure the Company's average production, average finding costs and average reserve replacement over three years. Based on the Company's probability assessment at December 31, 2011, it is considered probable that these three criteria will be met for all outstanding awards.

The 185,392 performance shares based on market conditions are earned, or not earned, based on the comparative performance of the Company's common stock measured against sixteen other companies in the Company's peer group over a three-year performance period. The performance shares based on market conditions have both an equity and liability component. The equity portion of the 2011 awards was valued on the grant date (February 17, 2011) and was not marked to market. The liability portion of the awards was valued as of December 31, 2011 on a mark-to-market basis.

The following assumptions were used for the performance shares based on market conditions using a Monte Carlo model to value the liability and equity components of the awards. The four primary inputs for the Monte Carlo model are the risk-free rate, volatility of returns, correlation in movement of total shareholder return and the expected dividend. An interpolated risk-free rate was generated from the Federal Reserve website for constant maturity treasuries for two and three year bonds (as of the reporting date) set equal to the remaining duration of the performance period. Volatility was set equal to the annualized daily volatility for the remaining duration of the performance period ending on the reporting date. Correlation in movement of total shareholder return was determined based on a correlation matrix that was created which identifies total shareholder return correlations for each pair of companies in the peer group, including the Company. The paired returns in the correlation matrix ranged from 56.8% to 100.0% for the Company and its peer group. The expected dividend is calculated using the total Company annual dividends expected to be paid divided by the closing price of the Company's stock at the valuation date. Based on these inputs discussed above, a ranking was projected identifying the Company's rank relative to the peer group for each award period.

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CABOT OIL & GAS CORPORATION

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

11. Stock-Based Compensation (Continued)

The following assumptions were used for the Monte Carlo model to determine the grant date fair value of the equity component of the performance share awards based on market conditions for the respective periods:

	Year Ended December 31,		
	2011	**2010**	**2009**
Fair Value per Performance Share Award Granted During the Period	**$ 15.62**	$ 6.50	$ 8.82
Assumptions			
Stock Price Volatility	**62.0%**	61.8%	57.6%
Risk Free Rate of Return	**1.3%**	1.4%	1.3%
Expected Dividend Yield	**0.2%**	0.3%	0.5%

The following assumptions were used in the Monte Carlo model to determine the fair value of the liability component of the performance share awards based on market conditions for the respective periods:

	December 31,		
	2011	**2010**	**2009**
Fair Value per Performance Share Award at the End of the Period	**$25.64 - $35.47**	$0.00 - $3.08	$7.19 - $8.12
Assumptions			
Stock Price Volatility	**41.9% - 42.7%**	70.7% - 71.7%	57.7% - 70.8%
Risk Free Rate of Return	**0.1% - 0.3%**	0.3% - 0.4%	0.5% - 1.4%
Expected Dividend Yield	**0.2%**	0.4%	0.3%

The long-term liability for market condition performance share awards, included in Other Liabilities in the Consolidated Balance Sheet, at December 31, 2011 and 2010 was $5.6 million and $0.6 million, respectively. The short-term liability, included in Accrued Liabilities in the Consolidated Balance Sheet, at December 31, 2011 and 2010 was $10.1 million and $2.4 million, respectively.

On December 31, 2011, the performance period ended for two types of performance shares awarded in 2009, including 594,960 shares measured based on internal performance metrics of the Company and 393,620 shares measured based on the Company's performance against a peer group. For the internal performance metric awards, the calculation of the average of the three years of the Company's three internal performance metrics was completed in the first quarter of 2012 and was certified by the Compensation Committee in February 2012. As the Company achieved the three internal performance metrics, 100% of the award, valued at $6.7 million based on the average of the high and low stock price on the grant date, was payable in 594,960 shares of common stock. For the peer group awards, due to the ranking of the Company compared to its peers in its predetermined peer group, 100% of the award, valued at $3.5 million based on the Monte Carlo value on the grant date, was payable in 393,620 shares of common stock and an additional 67%, equal to two-thirds of the total value of the award, calculated by using the average of the high and low stock price on December 30, 2011 multiplied by the number of performance shares earned, or $10.1 million, was payable in cash. The calculation of the award payout was certified by the Compensation Committee on January 3, 2012

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NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

11. Stock-Based Compensation (Continued)

and payout occurred in January 2012. The vesting of both types of shares discussed above will be reported in the first quarter of 2012.

The following table is a summary of performance share award activity for the year ended December 31, 2011:

Performance Share Awards	Shares	Weighted-Average Grant Date Fair Value per Share[(1)]	Weighted-Average Remaining Contractual Term (in years)	Aggregate Intrinsic Value (in thousands)[(2)]
Outstanding at December 31, 2010	2,337,892	$ 15.66		
Granted	789,514	19.25		
Issued and Fully Vested	(620,140)	20.08		
Forfeited	(65,700)	16.21		
Outstanding at December 31, 2011	**2,441,566**	**$ 15.68**	**0.9**	**$ 185,315**

(1) *The fair value figures in this table represent the fair value of the equity component of the performance share awards.*

(2) *The aggregate intrinsic value of performance share awards is calculated by multiplying the closing market price of the Company's stock on December 30, 2011 by the number of non-vested performance share awards outstanding.*

Of the performance shares that vested during 2011 shown in the table above, 471,744 shares were granted in 2008. A total of 145,024 shares (valued at $2.7 million) were measured based on the Company's performance against a peer group and were issued. A total of 287,600 shares (valued at $5.9 million) measured based on internal performance metrics of the Company were also issued. During 2011, 187,516 shares vested (valued at $3.9 million) which represents one-third of the three-year graded vesting schedule performance share awards granted in 2010, 2009 and 2008 with a grant date per share value of $20.27, $11.32 and $24.24, respectively.

During the year ended December 31, 2010, 694,340 performance share awards were granted to employees with a weighted-average grant date fair value per share of $19.24. Of the 820,538 performance shares that vested during 2010, 184,800 shares were granted in 2007. These shares (valued at $2.8 million) were measured based on the Company's performance against a peer group and were issued in addition to cash of $1.3 million. A total of 300,200 shares (valued at $5.3 million) measured based on internal performance metrics of the Company were also issued. During 2010, 335,538 shares vested (valued at $5.1 million) which represents one-third of the three-year graded vesting schedule performance share awards granted in 2009, 2008, and 2007 with a grant date per share value of $11.32, 24.24 and $17.61, respectively.

During the year ended December 31, 2009, 1,570,700 performance share awards were granted to employees with a weighted-average grant date fair value per share of $10.65. Of the 665,284 performance shares that vested during 2009, 211,600 shares were granted in 2006. These shares (valued at $1.7 million) were measured based on the Company's performance against a peer group and were issued in addition to cash of $1.8 million. A total of 311,600 shares (valued at $3.8 million) measured based on internal performance metrics of the Company were also issued. During 2009, 121,480 shares vested (valued at $2.5 million) which represents one-third of the three-year graded vesting schedule

CABOT OIL & GAS CORPORATION

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

11. Stock-Based Compensation (Continued)

performance share awards granted in 2008 and 2007 with a grant date per share value of $24.24 and $17.61, respectively. In addition, 20,604 performance shares vested as a result of early vesting schedules for certain employees. These awards met the performance criteria that the Company had positive operating income for 2008 and 2007.

During 2011, 2010 and 2009, 65,700, 80,360 and 240,180 performance shares, respectively, were forfeited.

Total unamortized compensation cost related to the equity component of performance shares at December 31, 2011 was $12.2 million and will be recognized over the next 1.9 years, computed by using the weighted-average of the time in years remaining to recognize unamortized expense. Total compensation cost recognized for both the equity and liability components of all performance share awards during the years ended December 31, 2011, 2010 and 2009 was $28.5 million, $12.4 million and $15.6 million, respectively.

Deferred Performance Shares

As of December 31, 2011, 267,086 shares of the Company's common stock representing vested performance share awards were deferred into the Rabbi Trust Deferred Compensation Plan. A total of 81,549 shares were sold out of the plan in 2011. During 2011, a decrease to the rabbi trust deferred compensation liability of $1.4 million was recognized, representing a decrease in the investment excluding the Company's common stock and the reduction in the liability due to shares that were sold out of the rabbi trust, partially offset by an increase in the closing price of the Company's common stock from December 31, 2010 to December 31, 2011. The increase in stock-based compensation expense was included in General and Administrative expense in the Consolidated Statement of Operations.

Supplemental Employee Incentive Plan

On July 24, 2008, the Company's Board of Directors adopted a Supplemental Employee Incentive Plan (the "Plan"). The Plan was intended to provide a compensation tool tied to stock market value creation to serve as an incentive and retention vehicle for full-time non-officer employees by providing for cash payments in the event the Company's common stock reaches a specified trading price.

The Plan provides for a final payout if, for any 20 trading days (which need not be consecutive) that fall within a period of 60 consecutive trading days ending on or before June 30, 2012, the closing price per share of the Company's common stock equals or exceeds the price goal of $52.50 per share. In such event, the 20th trading day on which such price condition is attained is the Final Trigger Date. The price goal is subject to adjustment by the Compensation Committee to reflect any stock splits, stock dividends or extraordinary cash distributions to stockholders. Under the Plan, each eligible employee may receive (upon approval by the Compensation Committee) a distribution of 50% of his or her base salary as of the Final Trigger Date. Payments under the final distribution will occur on the 15th business day following the Final Trigger Date. Payments are subject to certain other restrictions contained in the Plan.

The Plan also provided that a distribution of 20% of an eligible employee's base salary as of the Interim Trigger Date will be made (upon approval by the Compensation Committee) upon achieving

CABOT OIL & GAS CORPORATION

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

11. Stock-Based Compensation (Continued)

the interim price goal of $85 per share on or before June 30, 2010. The Company did not meet this interim trigger and therefore no distribution was made as of the Interim Trigger Date.

These awards have been accounted for as liability awards under ASC 718. The Company recognized an expense of $1.2 million for 2011, a benefit of $0.9 million for 2010 and an expense of $1.2 million for 2009, which is included in General and Administrative expense in the Consolidated Statement of Operations.

12. Derivative Instruments and Hedging Activities

The Company periodically enters into commodity derivative instruments to hedge its exposure to price fluctuations on natural gas and crude oil production. The Company's credit agreement restricts the ability of the Company to enter into commodity hedges other than to hedge or mitigate risks to which the Company has actual or projected exposure or as permitted under the Company's risk management policies and not subjecting the Company to material speculative risks. All of the Company's derivatives are used for risk management purposes and are not held for trading purposes. As of December 31, 2011, the Company had 37 derivative contracts open: 23 natural gas price swap arrangements, six natural gas basis swaps arrangements, three crude oil price swap arrangements and five natural gas collar arrangements. During 2011, the Company entered into 31 new derivative contracts covering anticipated natural gas and crude oil production for 2011, 2012, and 2013.

As of December 31, 2011, the Company had the following outstanding commodity derivatives:

Commodity and Derivative Type	Weighted-Average Contract Price	Volume	Contract Period
Derivatives Designated as Hedging Instruments			
Natural Gas Swaps	$5.22 per Mcf	95,998 Mmcf	Jan. 2012 - Dec. 2012
Natural Gas Collars	$6.20 Ceiling/ $5.15 Floor per Mcf	17,729 Mmcf	Jan. 2013 - Dec. 2013
Crude Oil Swaps	$98.28 per Bbl	732 Mbbl	Jan. 2012 - Dec. 2012
Derivatives Not Designated as Hedging Instruments			
Natural Gas Basis Swaps	$(0.27) per Mcf	17,042 Mmcf	Jan. 2012 - Dec. 2012

The change in fair value of derivatives designated as hedges that is effective is recorded to Accumulated Other Comprehensive Income in Stockholders' Equity in the Consolidated Balance Sheet. The ineffective portion of the change in the fair value of derivatives designated as hedges, and the change in fair value of derivatives not designated as hedges, are recorded currently in earnings as a component of Natural Gas revenue and Crude Oil and Condensate revenue in the Consolidated Statement of Operations.

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NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

12. Derivative Instruments and Hedging Activities (Continued)

The following tables reflect the fair value of derivative instruments on the Company's consolidated financial statements:

Effect of Derivative Instruments on the Consolidated Balance Sheet

		Fair Value Asset (Liability) December 31,	
(In thousands)	Balance Sheet Location	2011	2010
Derivatives Designated as Hedging Instruments			
Commodity Contracts	Derivative Instruments (current assets)	**$ 177,389**	$ 16,926
Commodity Contracts	Accrued Liabilities	**(385)**	
Commodity Contracts	Derivative Instruments (non-current assets)	**21,249**	
		198,253	16,926
Derivatives Not Designated as Hedging Instruments			
Commodity Contracts	Derivative Instruments (current assets)	**(3,126)**	
Commodity Contracts	Other Liabilities		(2,180)
		(3,126)	(2,180)
		$ 195,127	$ 14,746

At December 31, 2011 and 2010, unrealized gains of $198.3 million ($121.3 million, net of tax) and $16.9 million ($10.5 million, net of tax), respectively, were recorded in Accumulated Other Comprehensive Income in the Consolidated Balance Sheet. Based upon estimates at December 31, 2011, the Company expects to reclassify $108.3 million in after-tax income associated with its commodity hedges from Accumulated Other Comprehensive Income to the Consolidated Statement of Operations over the next 12 months.

Effect of Derivative Instruments on the Consolidated Statement of Operations

Derivatives Designated as Hedging Instruments (In thousands)	Amount of Gain (Loss) Recognized in OCI on Derivative (Effective Portion) Year Ended December 31, 2011	2010	2009	Location of Gain (Loss) Reclassified from Accumulated OCI into Income	Amount of Gain (Loss) Reclassified from Accumulated OCI into Income (Effective Portion) Year Ended December 31, 2011	2010	2009
Commodity Contracts	**$ 267,667**	$ 75,655	$ 154,086	Natural Gas Revenues	**$ 84,937**	$ 154,960	$ 371,915
				Crude Oil and Condensate Revenues	**1,403**	18,030	23,112
					86,340	172,990	$ 395,027

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CABOT OIL & GAS CORPORATION

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

12. Derivative Instruments and Hedging Activities (Continued)

For the years ended December 31, 2011, 2010 and 2009, respectively, there was no ineffectiveness recorded in our Consolidated Statement of Operations related to our derivative instruments.

Derivatives Not Designated as Hedging Instruments (In thousands)	Location of Gain (Loss) Recognized in Income on Derivative	Year Ended December 31, 2011	2010	2009
Commodity Contracts	Natural Gas Revenues	**$ (965)**	$ (226)	$ (1,954)

Additional Disclosures about Derivative Instruments and Hedging Activities

The use of derivative instruments involves the risk that the counterparties will be unable to meet their obligation under the agreement. The Company enters into derivative contracts with multiple counterparties in order to limit its exposure to individual counterparties. The Company also has netting arrangements with all of its counterparties that allow it to offset payables against receivables from separate derivative contracts with that counterparty.

The counterparties to the Company's derivative instruments are also lenders under its credit facility. The Company's credit facility and derivative instruments contain certain cross default and acceleration provisions that may require immediate payment of its derivative liability in certain situations.

13. Fair Value Measurements

ASC 820, "Fair Value Measurements and Disclosures," established a formal framework for measuring fair values of assets and liabilities in financial statements that are already required by GAAP to be measured at fair value. Fair value is 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 (exit price). The transaction is based on a hypothetical transaction in the principal or most advantageous market considered from the perspective of the market participant that holds the asset or owes the liability.

The Company utilizes market data or assumptions that market participants who are independent, knowledgeable and willing and able to transact would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable, market corroborated or generally unobservable. The Company attempts to utilize valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs. The Company is able to classify fair value balances based on the observability of those inputs. ASC 820 establishes formal fair value hierarchy based on the inputs used to measure fair value. The hierarchy gives the highest priority to Level 1 measurements and the lowest priority to Level 3 measurements.

The three levels of the fair value hierarchy as defined by ASC 820 are as follows:

> Level 1: Valuations utilizing quoted, unadjusted prices for identical assets or liabilities in active markets that the Company has the ability to access. This is the most reliable evidence of fair value and does not require a significant degree of judgment. Examples include exchange-traded derivatives and listed equities that are actively traded.

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CABOT OIL & GAS CORPORATION

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

13. Fair Value Measurements (Continued)

Level 2: Valuations utilizing quoted prices in markets that are not considered to be active or financial instruments for which all significant inputs are observable, either directly or indirectly for substantially the full term of the asset or liability. Financial instruments that are valued using models or other valuation methodologies are included. Models used should primarily be industry-standard models that consider various assumptions and economic measures, such as interest rates, yield curves, time value, volatilities, contract terms, current market prices, credit risk or other market-corroborated inputs. Examples include most over-the-counter derivatives (non-exchange traded), physical commodities, most structured notes and municipal and corporate bonds.

Level 3: Valuations utilizing significant, unobservable inputs. This provides the least objective evidence of fair value and requires a significant degree of judgment. Inputs may be used with internally developed methodologies and should reflect an entity's assumptions using the best information available about the assumptions that market participants would use in pricing an asset or liability. Examples include certain corporate loans, real-estate and private equity investments and long-dated or complex over-the-counter derivatives.

Depending on the particular asset or liability, input availability can vary depending on factors such as product type, longevity of a product in the market and other particular transaction conditions. In some cases, certain inputs used to measure fair value may be categorized into different levels of the fair value hierarchy. For disclosure purposes under ASC 820, the lowest level that contains significant inputs used in valuation should be chosen. In accordance with ASC 820, the Company has classified its assets and liabilities into these levels depending upon the data relied on to determine the fair values.

Non-Financial Assets and Liabilities

The Company discloses or recognizes its non-financial assets and liabilities, such as impairments of oil and gas properties and other assets, at fair value on a nonrecurring basis. During the years ended December 31, 2010 and 2009, the Company recorded impairment charges related to certain oil and gas properties and other assets. Refer to Note 2 for additional disclosures related to fair value associated with the impaired assets. As none of the Company's other non-financial assets and liabilities were impaired as of December 31, 2011, 2010 and 2009 and no other fair value measurements were required to be recognized on a non-recurring basis, additional disclosures were not provided.

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CABOT OIL & GAS CORPORATION

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

13. Fair Value Measurements (Continued)

Financial Assets and Liabilities

Our financial assets and liabilities are measured at fair value on a recurring basis. The following fair value hierarchy table presents information about the Company's financial assets and liabilities measured at fair value on a recurring basis as of December 31, 2011 and 2010:

(In thousands)	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance as of December 31, 2011
Assets				
Rabbi Trust Deferred Compensation Plan	$ 10,838	$	$	**$ 10,838**
Derivative Contracts			195,512	**195,512**
Total Assets	$ 10,838	$	$ 195,512	**$ 206,350**
Liabilities				
Rabbi Trust Deferred Compensation Plan	$ 20,187	$	$	**$ 20,187**
Derivative Contracts			385	**385**
Total Liabilities	$ 20,187	$	$ 385	**$ 20,572**

(In thousands)	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance as of December 31, 2010
Assets				
Rabbi Trust Deferred Compensation Plan	$ 15,788	$	$	$ 15,788
Derivative Contracts			16,926	16,926
Total Assets	$ 15,788	$	$ 16,926	$ 32,714
Liabilities				
Rabbi Trust Deferred Compensation Plan	$ 21,600	$	$	$ 21,600
Derivative Contracts			2,180	2,180
Total Liabilities	$ 21,600	$	$ 2,180	$ 23,780

The Company's investments associated with its Rabbi Trust Deferred Compensation Plan consist of mutual funds and deferred shares of the Company's common stock that are publicly traded and for which market prices are readily available. The derivative contracts were measured based on quotes from the Company's counterparties. Such quotes have been derived using valuation models that consider various inputs including current market and contractual prices for the underlying instruments, quoted forward prices for natural gas and crude oil, volatility factors and interest rates, such as a LIBOR curve for a similar length of time as the derivative contract term as applicable. These estimates are verified using relevant NYMEX futures contracts or are compared to multiple quotes obtained

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CABOT OIL & GAS CORPORATION

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

13. Fair Value Measurements (Continued)

from counterparties for reasonableness. The Company measured the nonperformance risk of its counterparties by reviewing credit default swap spreads for the various financial institutions in which it has derivative transactions. In times where the Company has net derivative contract liabilities, the nonperformance risk of the Company is evaluated using a market credit spread provided by the Company's bank. The impact of non-performance risk relative to the Company's derivative contracts was $1.4 million and $0.1 million at December 31, 2011 and 2010, respectively.

The following table sets forth a reconciliation of changes in the fair value of financial assets and liabilities classified as Level 3 in the fair value hierarchy:

	Year Ended December 31,		
(In thousands)	**2011**	**2010**	**2009**
Balance at beginning of period	**$ 14,746**	$ 112,307	$ 355,202
Total Gains or (Losses) (Realized or Unrealized):			
Included in Earnings[1]	**85,375**	172,764	393,073
Included in Other Comprehensive Income	**181,346**	(97,335)	(240,941)
Settlements	**(86,340)**	(172,990)	(395,027)
Transfers In and/or Out of Level 3			
Balance at end of period	**$ 195,127**	$ 14,746	$ 112,307

(1) *A loss of $1.0 million, $0.2 million and $2.0 million for the years ended December 31, 2011, 2010 and 2009, respectively, was unrealized and included in Natural Gas revenues in the Consolidated Statement of Operations.*

There were no transfers between Level 1 and Level 2 measurements for the years ended December 31, 2011, 2010 and 2009.

Fair Value of Other Financial Instruments

The estimated fair value of financial instruments is the amount at which the instrument could be exchanged currently between willing parties. The carrying amounts reported in the Consolidated Balance Sheet for cash and cash equivalents, accounts receivable and accounts payable approximate fair value due to the short-term maturities of these instruments.

The fair value of long-term debt is the estimated cost to acquire the debt, including a credit spread for the difference between the issue rate and the period end market rate. The credit spread is the Company's default or repayment risk. The credit spread (premium or discount) is determined by comparing the Company's fixed-rate notes and credit facility to new issuances (secured and unsecured) and secondary trades of similar size and credit statistics for both public and private debt. The fair value of all of the fixed-rate notes and credit facility is based on interest rates currently available to the Company.

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CABOT OIL & GAS CORPORATION

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

13. Fair Value Measurements (Continued)

The Company uses available market data and valuation methodologies to estimate the fair value of debt. The carrying amounts and fair values of long-term debt are as follows:

	December 31, 2011		December 31, 2010	
(In thousands)	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
Long-Term Debt	**$ 950,000**	**$ 1,082,531**	$ 975,000	$ 1,100,830

14. Earnings per Common Share

Basic EPS is computed by dividing net income (the numerator) by the weighted-average number of common shares outstanding for the period (the denominator). Diluted EPS is similarly calculated except that the denominator is increased using the treasury stock method to reflect the potential dilution that could occur if outstanding stock options and stock appreciation rights were exercised and stock awards were vested at the end of the applicable period.

The following is a calculation of basic and diluted weighted-average shares outstanding:

	December 31,		
	2011	2010	2009
Weighted-Average Shares Basic	**208,497,970**	207,822,862	207,231,942
Dilution Effect of Stock Options, Stock Appreciation Rights and Stock Awards at End of Period	**2,262,909**	2,566,708	2,133,552
Weighted-Average Shares Diluted	**210,760,879**	210,389,570	209,365,494
Weighted-Average Stock Awards and Shares Excluded from Diluted Earnings per Share due to the Anti-Dilutive Effect	**2,419**	567,132	521,636

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CABOT OIL & GAS CORPORATION

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS (Continued)

15. Accumulated Other Comprehensive Income / (Loss)

Changes in the components of accumulated other comprehensive income / (loss), net of taxes, were as follows:

(In thousands)	Net Gains / (Losses) on Cash Flow Hedges	Defined Benefit Pension and Postretirement Plans	Foreign Currency Translation Adjustment	Total
Balance at December 31, 2008	$ 223,068	$ (29,608)	$ (7,034)	$ 186,426
Net change in unrealized gain on cash flow hedges, net of taxes of $89,745	(151,196)			(151,196)
Net change in defined benefit pension and postretirement plans, net of taxes of $(162)		259		259
Change in foreign currency translation adjustment, net of taxes of $(4,116)			6,947	6,947
Balance at December 31, 2009	$ 71,872	$ (29,349)	$ (87)	$ 42,436
Net change in unrealized gain on cash flow hedges, net of taxes of $35,957	(61,378)			(61,378)
Net change in defined benefit pension and postretirement plans, net of taxes of ($9,088)		15,227		15,227
Change in foreign currency translation adjustment, net of taxes of ($20)			32	32
Balance at December 31, 2010	$ 10,494	$ (14,122)	$ (55)	$ (3,683)
Net change in unrealized gain on cash flow hedges, net of taxes of ($70,463)	110,864			110,864
Net change in defined benefit pension and postretirement plans, net of taxes of $2,225		(2,689)		(2,689)
Change in foreign currency translation adjustment, net of taxes of $(34)			55	55
Balance at December 31, 2011	**$ 121,358**	**$ (16,811)**	**$**	**$ 104,547**

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CABOT OIL & GAS CORPORATION

SUPPLEMENTAL OIL AND GAS INFORMATION (UNAUDITED)

Oil and Gas Reserves

Users of this information should be aware that the process of estimating quantities of "proved" and "proved developed" natural gas and crude oil reserves is very complex, requiring significant subjective decisions in the evaluation of all available geological, engineering and economic data for each reservoir. The data for a given reservoir may also change substantially over time as a result of numerous factors including, but not limited to, additional development activity, evolving production history and continual reassessment of the viability of production under varying economic conditions. As a result, revisions to existing reserve estimates may occur from time to time. Although every reasonable effort is made to ensure that reserve estimates reported represent the most accurate assessments possible, the subjective decisions and variances in available data for various reservoirs make these estimates generally less precise than other estimates included in the financial statement disclosures.

Estimates of total proved reserves at December 31, 2011, 2010 and 2009 were based on studies performed by the Company's petroleum engineering staff. The estimates were computed using the 12-month average oil and natural gas index prices, calculated as the unweighted arithmetic average for the first day of the month price for each month during the respective year, as prescribed under the revised rules codified in ASC 932, "Extractive Activities Oil and Gas." The estimates were audited by Miller and Lents, Ltd., who indicated that based on their investigation and subject to the limitations described in their audit letter, they believe the results of those estimates and projections were reasonable in the aggregate.

No major discovery or other favorable or unfavorable event after December 31, 2011, is believed to have caused a material change in the estimates of proved or proved developed reserves as of that date.

As of December 31, 2009, the Company adopted the guidance in ASC 932 related to oil and gas reserve estimation and disclosures in conjunction with the year-end reserve reporting as a change in accounting principle that is inseparable from a change in accounting estimate. The impact of the adoption of this guidance on the Company's financial statements was not practicable to estimate due to the challenges associated with computing a cumulative effect of adoption by preparing reserve reports under both the old and new guidance.

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The following tables illustrate the Company's net proved reserves, including changes, and proved developed and proved undeveloped reserves for the periods indicated, as estimated by the Company's engineering staff. All reserves are located within the continental United States in 2011, 2010 and 2009.

	Natural Gas (Mmcf)	Oil & Liquids (Mbbl)	Total (Mmcfe)[1]
December 31, 2008[2]	1,885,993	9,341	1,942,037
Revision of Prior Estimates[3]	(193,767)	(1,062)	(200,143)
Extensions, Discoveries and Other Additions[4]	459,612	544	462,880
Production	(97,914)	(844)	(102,976)
Purchases of Reserves in Place	9		9
Sales of Reserves in Place	(40,771)	(196)	(41,949)
December 31, 2009	2,013,162	7,783	2,059,858
Revision of Prior Estimates[5]	139,016	(379)	136,742
Extensions, Discoveries and Other Additions[4]	632,980	2,944	650,644
Production	(125,474)	(858)	(130,622)
Purchases of Reserves in Place	593	4	617
Sales of Reserves in Place	(16,119)	(3)	(16,137)
December 31, 2010	2,644,158	9,491	2,701,102
Revision of Prior Estimates[6]	22,035	(80)	21,556
Extensions, Discoveries and Other Additions[4]	628,456	13,583	709,954
Production	(178,848)	(1,444)	(187,512)
Purchases of Reserves in Place			
Sales of Reserves in Place[7]	(205,885)	(1,080)	(212,365)
December 31, 2011	**2,909,916**	**20,470**	**3,032,735**
Proved Developed Reserves			
December 31, 2008[2]	1,308,155	6,728	1,348,521
December 31, 2009	1,288,169	6,082	1,324,663
December 31, 2010	1,681,451	7,129	1,724,225
December 31, 2011	**1,734,088**	**10,922**	**1,799,619**
Proved Undeveloped Reserves			
December 31, 2008[5]	577,838	2,613	593,516
December 31, 2009	724,993	1,701	735,199
December 31, 2010	962,707	2,362	976,877
December 31, 2011	**1,175,828**	**9,548**	**1,233,116**

(1) *Includes natural gas and natural gas equivalents determined by using the ratio of 6 Mcf of natural gas to 1 Bbl of crude oil, condensate or natural gas liquids.*

(2) *Prior to 2009, reserve estimates were based on year end prices.*

(3) *The net downward revision of 200.1 Bcfe was primarily due to (i) downward revisions of 101.6 Bcfe due to lower 2009 oil and natural gas prices compared to 2008 and (ii) downward revisions of 120.4 Bcfe due to the removal of proved undeveloped reserves scheduled for development beyond five years primarily due to the application of the SEC's oil and gas reserve calculation methodology effective beginning in 2009, partially offset by 21.9 Bcfe of positive performance revisions.*

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(4) *Extensions, discoveries and other additions were primarily related to drilling activity in the Dimock field located in northeast Pennsylvania. The Company added 616.1 Bcfe, 536.6 Bcfe and 361.6 Bcfe of proved reserves in this field in 2011, 2010 and 2009, respectively.*

(5) *The net upward revision of 136.7 Bcfe was primarily due to (i) an upward performance revision of 284.4 Bcfe, primarily in the Dimock field in northeast Pennsylvania, and (ii) an upward revision of 35.0 Bcfe associated with increased reserve commodity pricing partially offset by a downward revision of 182.7 Bcfe of proved undeveloped reserves that are no longer in our five-year development plan.*

(6) *The net upward revision of 21.6 Bcfe was primarily due to an upward performance revision of 214.9 Bcfe, primarily in the Dimock field in northeast Pennsylvania, partially offset by (i) a downward revision of 189.8 Bcfe of proved undeveloped reserves that are no longer in our five-year development plan and (ii) a downward revision of 3.6 Bcfe associated with reduced reserve commodity pricing.*

(7) *Sales of reserves in place were primarily related to the divestiture of certain oil and gas properties in Colorado, Utah and Wyoming in October 2011 which represented 170.3 Bcfe.*

Capitalized Costs Relating to Oil and Gas Producing Activities

The following table illustrates the total amount of capitalized costs relating to natural gas and crude oil producing activities and the total amount of related accumulated depreciation, depletion and amortization.

	December 31,		
(In thousands)	**2011**	**2010**	**2009**
Aggregate Capitalized Costs Relating to Oil and Gas Producing Activities	**$ 5,794,724**	$ 5,598,842	$ 4,905,424
Aggregate Accumulated Depreciation, Depletion and Amortization	**1,864,729**	1,840,091	1,550,837
Net Capitalized Costs	**$ 3,929,995**	$ 3,758,751	$ 3,354,587

Costs Incurred in Oil and Gas Property Acquisition, Exploration and Development Activities

Costs incurred in property acquisition, exploration and development activities were as follows:

	Year Ended December 31,		
(In thousands)	**2011**	**2010**	**2009**
Property Acquisition Costs, Proved	**$**	$ 801	$ 394
Property Acquisition Costs, Unproved	**71,134**	130,675	145,681
Exploration Costs	**53,484**	66,368	68,196
Development Costs	**763,635**	630,511	379,140
Total Costs	**$ 888,253**	$ 828,355	$ 593,411

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves

The following information has been developed utilizing the guidance in ASC 932 and based on natural gas and crude oil reserve and production volumes estimated by the Company's engineering staff. It can be used for some comparisons, but should not be the only method used to evaluate the Company or its performance. Further, the information in the following table may not represent realistic

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assessments of future cash flows, nor should the Standardized Measure of Discounted Future Net Cash Flows be viewed as representative of the current value of the Company.

The Company believes that the following factors should be taken into account when reviewing the following information:

Future costs and selling prices will probably differ from those required to be used in these calculations.

Due to future market conditions and governmental regulations, actual rates of production in future years may vary significantly from the rate of production assumed in the calculations.

Selection of a 10% discount rate is arbitrary and may not be a reasonable measure of the relative risk that is part of realizing future net oil and gas revenues.

Future net revenues may be subject to different rates of income taxation.

Under the Standardized Measure, future cash inflows for 2011, 2010 and 2009 were estimated by using the 12-month average oil and gas index prices, calculated as the unweighted arithmetic average for the first day of the month price for each month during the year, as prescribed under the revised rules codified in ASC 932 that the Company adopted on January 1, 2009, and by applying year end oil and gas prices to the estimated future production of year end proved reserves for 2008.

The average prices (adjusted for basis and quality differentials) related to proved reserves at December 31, 2011, 2010 and 2009 for natural gas ($ per Mcf) were $4.27, $4.33 and $3.84, respectively, and for oil ($ per Bbl) were $94.00, $74.25 and $55.41, respectively. Future cash inflows were reduced by estimated future development and production costs based on year end costs to arrive at net cash flow before tax. Future income tax expense was computed by applying year end statutory tax rates to future pretax net cash flows, less the tax basis of the properties involved and utilization of available tax carryforwards related to oil and gas operations. ASC 932 requires the use of a 10% discount rate.

Management does not solely use the following information when making investment and operating decisions. These decisions are based on a number of factors, including estimates of proved reserves, and varying price and cost assumptions considered more representative of a range of anticipated economic conditions.

Standardized Measure is as follows:

	Year Ended December 31,		
(In thousands)	**2011**	**2010**	**2009**
Future Cash Inflows	**$ 14,303,990**	$ 12,147,617	$ 8,170,009
Future Production Costs	**(3,435,947)**	(2,377,402)	(2,353,974)
Future Development Costs	**(1,617,548)**	(1,670,796)	(1,234,203)
Future Income Tax Expenses	**(2,880,182)**	(2,357,935)	(1,089,282)
Future Net Cash Flows	**6,370,313**	5,741,484	3,492,550
10% Annual Discount for Estimated Timing of Cash Flows	**(3,211,587)**	(3,006,975)	(1,860,815)
Standardized Measure of Discounted Future Net Cash Flows	**$ 3,158,726**	$ 2,734,509	$ 1,631,735

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Changes in Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves

The following is an analysis of the changes in the Standardized Measure:

	Year Ended December 31,		
(In thousands)	**2011**	**2010**	**2009**
Beginning of Year	**$ 2,734,509**	$ 1,631,735	$ 2,059,955
Discoveries and Extensions, Net of Related Future Costs	**1,026,961**	780,917	381,691
Net Changes in Prices and Production Costs	**219,478**	991,942	(861,939)
Accretion of Discount	**325,634**	164,189	236,520
Revisions of Previous Quantity Estimates	**28,443**	164,851	(159,531)
Timing and Other	**(190,427)**	(105,331)	(104,117)
Development Costs Incurred	**190,295**	115,560	109,384
Sales and Transfers, Net of Production Costs	**(648,261)**	(481,556)	(286,594)
Net Purchases / (Sales) of Reserves in Place	**(207,557)**	(16,124)	(38,730)
Net Change in Income Taxes	**(320,349)**	(511,674)	295,096
End of Year	**$ 3,158,726**	$ 2,734,509	$ 1,631,735

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CABOT OIL & GAS CORPORATION

SELECTED DATA (UNAUDITED)
QUARTERLY FINANCIAL INFORMATION

(In thousands, except per share amounts)	First	Second	Third	Fourth	Total
2011					
Operating Revenues	**$ 209,026**	**$ 240,696**	**$ 262,117**	**$ 268,025**	**$ 979,864**
Operating Income[1]	**36,390**	**106,618**	**65,233**	**98,609**	**306,850**
Net Income[1]	**12,886**	**54,677**	**28,482**	**26,363**	**122,408**
Basic Earnings per Share[2]	**0.06**	**0.27**	**0.14**	**0.13**	**0.59**
Diluted Earnings per Share[2]	**0.06**	**0.26**	**0.14**	**0.13**	**0.58**
2010					
Operating Revenues	$ 216,345	$ 200,241	$ 224,062	$ 222,456	$ 863,104
Impairment of Oil and Gas Properties and Other Assets			35,789	5,114	40,903
Operating Income[3]	60,589	52,068	22,273	131,509	266,439
Net Income[3]	28,696	21,682	3,898	49,110	103,386
Basic Earnings per Share[2]	0.14	0.11	0.02	0.24	0.50
Diluted Earnings per Share[2]	0.14	0.11	0.02	0.24	0.49

(1) *Operating Income and Net Income in 2011 contain a $34.2 million gain on the disposition of certain Haynesville and Bossier Shale oil and gas properties in east Texas in the second quarter and an aggregate gain of $29.2 million from the sale of various other properties primarily in the fourth quarter of 2011.*

(2) *All Earnings per Share figures have been retroactively adjusted for the 2-for-1 split of the Company's common stock effective January 25, 2012.*

(3) *Operating Income and Net Income in 2010 contain an aggregate gain of $4.5 million from the sale of various oil and gas properties in the second quarter and a gain of $11.4 million related to the sale of certain oil and gas properties in Texas, a gain of $49.3 million associated with the sale of the Pennsylvania gathering infrastructure and a $40.7 million gain from the sale of the Company's investment in Tourmaline in the fourth quarter of 2010.*

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

None.

ITEM 9A. CONTROLS AND PROCEDURES

Conclusion Regarding the Effectiveness of Disclosure Controls and Procedures and Changes in Internal Control over Financial Reporting

As of December 31, 2011, the Company carried out an evaluation, under the supervision and with the participation of the Company's management, including the Company's Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of the Company's disclosure controls and procedures pursuant to Rules 13a-15 and 15d-15 of the Securities Exchange Act of 1934 (the "Exchange Act"). Based upon that evaluation, the Chief Executive Officer and Chief Financial Officer concluded that the Company's disclosure controls and procedures are effective, in all material respects, with respect to the recording, processing, summarizing and reporting, within the time periods specified in the Commission's rules and forms, of information required to be disclosed by the Company in the reports that it files or submits under the Exchange Act.

There were no changes in the Company's internal control over financial reporting that occurred during the fourth quarter that have materially affected, or are reasonably likely to materially effect, the Company's internal control over financial reporting.

Management's Report on Internal Control over Financial Reporting

The management of Cabot Oil & Gas Corporation is responsible for establishing and maintaining adequate internal control over financial reporting. Cabot Oil & Gas Corporation'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. 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.

Cabot Oil & Gas Corporation's management assessed the effectiveness of the Company's internal control over financial reporting as of December 31, 2011. In making this assessment, it used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in Internal Control Integrated Framework. Based on this assessment management has concluded that, as of December 31, 2011, the Company's internal control over financial reporting is effective at a reasonable assurance level based on those criteria.

The effectiveness of Cabot Oil & Gas Corporation's internal control over financial reporting as of December 31, 2011, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears herein.

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

The information required by this Item is incorporated by reference to the Company's definitive Proxy Statement in connection with the 2012 annual stockholders' meeting. In addition, the information set forth under the caption "Business Other Business Matters Corporate Governance Matters" in Item 1 regarding our Code of Business Conduct is incorporated by reference in response to this Item.

ITEM 11. EXECUTIVE COMPENSATION

The information required by this Item is incorporated by reference to the Company's definitive Proxy Statement in connection with the 2012 annual stockholders' meeting.

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

The information required by this Item is incorporated by reference to the Company's definitive Proxy Statement in connection with the 2012 annual stockholders' meeting.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

The information required by this Item is incorporated by reference to the Company's definitive Proxy Statement in connection with the 2012 annual stockholders' meeting.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

The information required by this Item is incorporated by reference to the Company's definitive Proxy Statement in connection with the 2012 annual stockholders' meeting.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

A. INDEX

1. Consolidated Financial Statements

See Index on page 55.

2. Financial Statement Schedules

Financial statement schedules listed under SEC rules but not included in this report are omitted because they are not applicable or the required information is provided in the notes to our consolidated financial statements.

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3. Exhibits

The following instruments are included as exhibits to this report. Those exhibits below incorporated by reference herein are indicated as such by the information supplied in the parenthetical thereafter. If no parenthetical appears after an exhibit, copies of the instrument have been included herewith. Our Commission file number is 1-10447.

Exhibit Number	Description
3.1	Restated Certificate of Incorporation of the Company (Form 8-K for January 21, 2010).
3.2	Amended and Restated Bylaws of the Company amended January 14, 2010 (Form 8-K for January 14, 2010).
4.1	Form of Certificate of Common Stock of the Company (Registration Statement No. 33-32553).
4.2	Note Purchase Agreement dated as of July 26, 2001 among Cabot Oil & Gas Corporation and the Purchasers listed therein (Form 8-K for August 30, 2001).
	(a) Amendment No. 1 to Note Purchase Agreement, dated as of June 30, 2010 (Form 10-Q for the quarter ended June 30, 2010).
	(b) Amendment No. 2 to Note Purchase Agreement, dated as of September 28, 2010 (Form 10-Q for the quarter ended September 30, 2010).
4.3	Note Purchase Agreement dated as of July 16, 2008 among Cabot Oil & Gas Corporation and the Purchasers named therein (Form 8-K for July 16, 2008).
	(a) Amendment No. 1 to Note Purchase Agreement, dated as of June 30, 2010 (Form 10-Q for the quarter ended June 30, 2010).
4.4	Note Purchase Agreement dated as of December 1, 2008 among Cabot Oil & Gas Corporation and the Purchasers named therein (Form 10-K for 2008).
	(a) Amendment No. 1 to Note Purchase Agreement, dated as of June 30, 2010 (Form 10-Q for the quarter ended June 30, 2010).
4.5	Note Purchase Agreement dated as of December 30, 2010 among Cabot Oil & Gas Corporation and the Purchasers named therein (Form 10-K for 2010).
4.6	Credit Agreement, dated as of September 22, 2010, among the Company, JPMorgan Chase Bank, N.A., as Administrative Agent, Banc of America Securities LLC, as Syndication Agent, Bank of Montreal, as Documentation Agent, and the Lenders party thereto (Form 10-Q for the quarter ended September 30, 2010).
*10.1	Form of Change in Control Agreement between the Company and Certain Officers (Form 10-K for 2008).
	(a) Form of Change in Control Agreement between the Company and Certain Officers (Confirmation that Certain Benefits no Longer Apply).
*10.2	Form of Supplemental Executive Retirement Agreement (Form 10-K for 2008).
	(a) Agreement Concerning SERP.
*10.3	Form of Indemnity Agreement between the Company and Certain Officers (Form 10-K for 1997).

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Exhibit Number	Description
*10.4	Deferred Compensation Plan of the Company, as Amended and Restated, Effective January 1, 2011 (Form 10-Q for the quarter ended June 30, 2011).
10.5	Trust Agreement dated September 2000 between Harris Trust and Savings Bank and the Company (Form 10-K for 2001).
*10.6	Employment Agreement between the Company and Dan O. Dinges dated August 29, 2001 (Form 10-K for 2001).
	(a) Amendment to Employment Agreement between the Company and Dan O. Dinges, effective December 31, 2008 (Form 10-K for 2008).
*10.7	2004 Incentive Plan (Form 10-Q for the quarter ended June 30, 2004).
	(a) First Amendment to the 2004 Incentive Plan effective February 23, 2007 (Form 10-Q for the quarter ended March 31, 2007).
	(b) Second Amendment to the 2004 Incentive Plan Amendment, effective as of January 1, 2009 (Form 10-K for 2008).
*10.8	2004 Performance Award Agreement (Form 10-Q for the quarter ended June 30, 2004).
*10.9	2004 Annual Target Cash Incentive Plan Measurement Criteria for Cabot Oil & Gas Corporation (Form 8-K for February 10, 2005).
*10.10	Form of Restricted Stock Awards Terms and Conditions for Cabot Oil & Gas Corporation (Form 8-K for February 10, 2005).
*10.11	2005 Form of Non-Employee Director Restricted Stock Unit Award Agreement (Form 8-K for May 24, 2005).
*10.12	Savings Investment Plan of the Company, as amended and restated effective January 1, 2001 (Form 10-K for 2005).
	(a) First Amendment to the Savings Investment Plan effective January 1, 2002 (Form 10-K for 2005).
	(b) Second Amendment to the Savings Investment Plan effective January 1, 2003 (Form 10-K for 2005).
	(c) Third Amendment to the Savings Investment Plan effective January 1, 2005 (Form 10-K for 2005).
*10.13	Forms of Award Agreements for Executive Officers under 2004 Incentive Plan (Form 10-K for 2006).
	(a) Form of Restricted Stock Award Agreement (Form 10-K for 2006).
	(b) Form of Stock Appreciation Rights Award Agreement (Form 10-K for 2006).
	(c) Form of Performance Share Award Agreement (Form 10-K for 2006).
10.14	Cabot Oil & Gas Corporation Mineral, Royalty and Overriding Royalty Interest Plan (Registration Statement No. 333-135365).
	(a) Form of Conveyance of Mineral and/or Royalty Interest (Registration Statement No. 333-135365).
	(b) Form of Conveyance of Overriding Royalty Interest (Registration Statement No. 333-135365).

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Exhibit Number	Description
*10.15	Form of Amendment of Employee Award Agreements (Form 8-K for December 19, 2006).
*10.16	Savings Investment Plan of the Company, as amended and restated effective January 1, 2006 (Form 10-K for 2006).
	(a) First Amendment to the Savings Investment Plan of the Company effective January 1, 2006 (Form 10-K for 2007).
	(b) Second Amendment to the Savings Investment Plan of the Company effective April 23, 2008 (Form 10-Q for the quarter ended March 31, 2008).
	(c) Third Amendment to the Savings Investment Plan of the Company effective July 1, 2008 (Form 10-K for 2008).
	(d) Fourth Amendment to the Savings Investment Plan of the Company effective January 1, 2008 (Form 10-K for 2008).
*10.17	Cabot Oil & Gas Corporation Pension Plan, as amended and restated effective September 30, 2010 (Form 10-K for 2010).
*10.18	Savings Investment Plan of the Company, as amended and restated effective January 1, 2009 (Form 10-K for 2009).
	(a) First Amendment to the Savings Investment Plan of the Company effective January 1, 2009 (Form 10-K for 2010).
21.1	Subsidiaries of Cabot Oil & Gas Corporation.
23.1	Consent of PricewaterhouseCoopers LLP.
23.2	Consent of Miller and Lents, Ltd.
31.1	302 Certification Chairman, President and Chief Executive Officer.
31.2	302 Certification Vice President and Chief Financial Officer.
32.1	906 Certification.
99.1	Miller and Lents, Ltd. Audit Letter.
101.INS	XBRL Instance Document.
101.SCH	XBRL Taxonomy Extension Schema Document.
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document.
101.LAB	XBRL Taxonomy Extension Label Linkbase Document.
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document.
101.DEF	XBRL Taxonomy Extension Definition Linkbase Document.

* Compensatory plan, contract or arrangement.

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SIGNATURES

Pursuant to the requirements of Section 13 and 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, in the City of Houston, State of Texas, on the 28th of February 2012.

CABOT OIL & GAS CORPORATION

By: /s/ DAN O. DINGES

Dan O. Dinges
Chairman, President and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Signature	Title	Date
/s/ DAN O. DINGES Dan O. Dinges	Chairman, President and Chief Executive Officer (Principal Executive Officer)	February 28, 2012
/s/ SCOTT C. SCHROEDER Scott C. Schroeder	Vice President, Chief Financial Officer and Treasurer (Principal Financial Officer)	February 28, 2012
/s/ TODD M. ROEMER Todd M. Roemer	Controller (Principal Accounting Officer)	February 28, 2012
/s/ RHYS J. BEST Rhys J. Best	Director	February 28, 2012
/s/ DAVID M. CARMICHAEL David M. Carmichael	Director	February 28, 2012
/s/ JAMES R. GIBBS James R. Gibbs	Director	February 28, 2012
/s/ ROBERT L. KEISER Robert L. Keiser	Director	February 28, 2012
/s/ ROBERT KELLEY Robert Kelley	Director	February 28, 2012
/s/ P. DEXTER PEACOCK P. Dexter Peacock	Director	February 28, 2012

/s/ W. MATT RALLS W. Matt Ralls	Director	February 28, 2012
/s/ WILLIAM P. VITITOE William P. Vititoe	Director	February 28, 2012