CABOT OIL & GAS CORP
Form 10-K
February 27, 2008

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, 2007

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)**

1200 Enclave Parkway, Houston, Texas 77077

(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**
Rights to Purchase Preferred Stock	**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 x No ¨

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

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 x No ¨

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of 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 x.

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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 x	Accelerated filer ¨
Non-accelerated filer ¨ (Do not check if a smaller reporting company)	Smaller reporting company ¨

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

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 29, 2007) was approximately $3.6 billion.

As of February 25, 2008, there were 97,768,036 shares of Common Stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Proxy Statement for the Annual Meeting of Stockholders to be held April 30, 2008 are incorporated by reference into Part III of this report.

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PART III

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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 forward-looking statements. These statements involve risks and uncertainties, including, but not limited to, market factors, market prices (including regional basis differentials) of natural gas and oil, results of future drilling and marketing activity, future production and costs, 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.

CERTAIN DEFINITIONS

The following is a list of commonly used terms and their definitions included within this Annual Report on Form 10-K:

Abbreviated Term	**Definition**
Mcf	Thousand cubic feet
Mmcf	Million cubic feet
Bcf	Billion cubic feet
Bbl	Barrel
Mbbls	Thousand barrels
Mcfe	Thousand cubic feet of natural gas equivalents
Mmcfe	Million cubic feet of natural gas equivalents
Bcfe	Billion cubic feet of natural gas equivalents
Mmbtu	Million British thermal units
NGL	Natural gas liquids

PART I

ITEM 1. BUSINESS

OVERVIEW

Cabot Oil & Gas Corporation is an independent oil and gas company engaged in the development, exploitation and exploration of oil and gas properties located in North America. Our five principal areas of operation are the Appalachian Basin, onshore Gulf Coast, including south and east Texas and north Louisiana, the Rocky Mountains, the Anadarko Basin and the deep gas basin of Western Canada. Operationally, we have four regional offices located in Houston, Texas; Charleston, West Virginia; Denver, Colorado; and Calgary, Alberta.

Net income for 2007 of $167.4 million, or $1.73 per share, was lower than the prior year s net income of $321.2 million, or $3.32 per share, by $153.8 million, or 48%. The year-over-year net income decrease was primarily due to the recognition of a gain on sale of assets of $231.2 million ($144.5 million, net of tax) in 2006 related to the disposition of our offshore portfolio and certain south Louisiana properties to a third party, which was substantially completed in 2006 (the 2006 south Louisiana and offshore properties sale) and, to a lesser extent, lower operating revenues as discussed below. Additionally, operating expenses increased by $5.8 million between 2006 and 2007 principally due to increased depreciation, depletion and amortization costs and impairment charges, partially offset by lower exploration and general and administrative expenses. These lower operating revenues and increased operating expenses, along with a $1.2 million decrease in interest and other expense, reduced income before income taxes by $253.0 million and consequently decreased income tax expense by $99.2 million. Also contributing to the decrease in income taxes was the decrease in the effective tax rate primarily due to a reduction in our overall state income tax liability for 2007 relating to the 2006 south Louisiana and offshore properties sale.

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Operating revenues decreased by $29.8 million, or four percent, over the prior year as described below. Natural gas production revenues increased by $13.5 million, or two percent, over the prior year due to an increase in realized natural gas prices and an increase in natural gas production in the West region, East region and Canada, partially offset by decreased natural gas production in the Gulf Coast region as a result of the 2006 south Louisiana and offshore properties sale. Crude oil and condensate revenues decreased by $36.2 million, or 40%, over the prior year mainly due to decreased crude oil and condensate production in the Gulf Coast region as a result of the 2006 south Louisiana and offshore properties sale, partially offset by an increase in crude oil realized prices. Excluding $70.5 million and $47.4 million, respectively, of natural gas and crude oil revenues from our 2006 results that were attributable to the 2006 south Louisiana and offshore properties sale, natural gas revenues for 2007 would have increased by 17% and crude oil revenues would have increased by 26%. Brokered natural gas revenues decreased by $0.5 million due to a decrease in brokered volumes, offset in part by an increase in sales price.

In 2007, energy commodity prices remained strong throughout the year. Our 2007 average realized natural gas price was $7.23 per Mcf, one percent higher than the 2006 average realized price of $7.13. Our 2007 average realized crude oil price was $67.16 per Bbl, three percent higher than the 2006 average realized price of $65.03. These realized prices include realized gains and losses resulting from commodity derivatives (zero-cost collars or swaps). For information about the impact of these derivatives on realized prices, refer to the Results of Operations section in Item 7 of this Annual Report on Form 10-K. Our balance sheet, strengthened by the 2006 south Louisiana and offshore properties sale, and a hedge position covering approximately half of our anticipated production at levels exceeding our budgeted prices, allowed us to once again expand our capital program. In 2007, we pursued and completed the largest investment program in our history ($636.2 million) which was funded largely through cash flow from operations and, to a lesser extent, borrowings on our revolving credit facility. We believe our balance sheet and availability under our credit facility provides sufficient liquidity to pursue our 2008 program and evaluate other opportunities.

On an equivalent basis, our production level in 2007 decreased by three percent from 2006. We produced 85.5 Bcfe, or 234.1 Mmcfe per day, in 2007, as compared to 88.2 Bcfe, or 241.7 Mmcfe per day, in 2006. Natural gas production increased to 80.5 Bcf in 2007 from 79.7 Bcf in 2006 primarily due to increased production in the West and East regions associated with an increase in the drilling program and an increase in Canada due to increased pipeline capacity and drilling activity in the Hinton field, partially offset by a decline in Gulf Coast production. Excluding 9.0 Bcf of natural gas production sold in the 2006 south Louisiana and offshore properties sale, total natural gas production would have increased by 14%. Gulf Coast natural gas production decreased from 29.9 Bcf in 2006 to 26.8 Bcf in 2007 primarily due to the 2006 south Louisiana and offshore properties sale. Excluding 9.0 Bcf of production sold in that sale, Gulf Coast production would have increased 28% in 2007 over 2006, primarily due to increased drilling in the Minden, Angie (County Line) and McCampbell fields and recompletions in the Raymondville field. Oil production decreased by 582 Mbbls from 1,405 Mbbls in 2006 to 823 Mbbls in 2007, due primarily to a decrease in production in the Gulf Coast region. Excluding 707 Mbbls of crude oil production related to the 2006 south Louisiana and offshore properties sale, oil production would have increased by 18% from 2006 to 2007 mainly due to an increase in drilling and workover activity in the McCampbell field and, to a lesser extent, in the Minden field. Oil production increased slightly in the East region and in Canada and decreased by 17% in the West region due to natural decline. Excluding 13.3 Bcfe of equivalent production sold in the 2006 south Louisiana and offshore properties sale, total equivalent production would have increased by 10.6 Bcfe, or 14%.

A portion of our production was covered by oil and gas hedge instruments throughout 2006 and 2007. Again during 2007 as in 2006, we employed the use of collars to hedge our price exposure on our production. In addition, at the end of 2007, we employed the use of cash flow swaps to cover a portion of our 2008 natural gas production. For 2007, collars covered 53% of natural gas production and had a weighted-average floor of $8.99 per Mcf and a weighted-average ceiling of $12.19 per Mcf. At December 31, 2007, approximately 38% of the anticipated 2008 natural gas production is hedged using collars with a weighted-average floor of $8.17 per Mcf and a weighted-average ceiling of $10.14 per Mcf. Swaps as of December 31, 2007 cover approximately six percent of our anticipated 2008 natural gas production with a weighted-average price of $7.44 per Mcf. For 2007, collars covered 44% of crude oil production with a floor of $60.00 per Bbl and a ceiling of $80.00 per Bbl. At December 31, 2007, approximately 49% of our anticipated crude oil production is hedged for 2008 with a floor of

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$60.00 per Bbl and a ceiling of $80.00 per Bbl. As of December 31, 2007, no derivatives are in place for 2009. Our decision to hedge 2008 production fits with our risk management strategy and allows us to lock in the benefit of high commodity prices on a portion of our anticipated production.

For the year ended December 31, 2007, we drilled 461 gross wells (391 net) with a success rate of 96% compared to 387 gross wells (307 net) with a success rate of 96% for the prior year. In 2008, we plan to drill approximately 419 gross wells (366 net). The number of wells we plan to drill in 2008 is down from 2007 primarily due to lower planned activity in the Rocky Mountains area based on lower natural gas prices and lower planned activity in Canada based on uncertainty around royalties and exchange rates. Our 2007 capital and exploration spending was $636.2 million compared to $537.5 million of total capital and exploration spending in 2006. In both 2007 and 2006, we allocated our planned program for capital and exploration expenditures among our various operating regions based on return expectations, availability of services and human resources. We plan to continue such method of allocation in 2008. Funding of the program is expected to be provided by operating cash flow, existing cash and increased borrowings, if required. We remain focused on our strategies of pursuing lower risk drilling opportunities that provide more predictable results and selectively pursuing impact exploration opportunities as we accelerate drilling on our accumulated acreage position. For 2008, the Gulf Coast region will start the year with the largest allocation of capital, followed by the East, the West and Canada. We believe these strategies are appropriate in the current industry environment and will continue to add shareholder value over the long term. In 2008, we plan to spend approximately $490 million on capital and exploration activities.

Our proved reserves totaled approximately 1,616 Bcfe at December 31, 2007, of which 97% was natural gas. This reserve level was up by 14 percent from 1,416 Bcfe at December 31, 2006 on the strength of results from our drilling program and the increase in our capital spending.

The following table presents certain reserve, production and well information as of December 31, 2007.

				West			
	East	**Gulf Coast**	**Rocky Mountains**	**Mid-Continent**	**Total**	**Canada**	**Total**
Proved Reserves at Year End *(Bcfe)*							
Developed	551.2	207.9	206.6	177.8	384.4	32.6	**1,176.1**
Undeveloped	227.2	116.3	65.0	28.1	93.1	3.2	**439.8**
Total	778.4	324.2	271.6	205.9	477.5	35.8	**1,615.9**
Average Daily Production *(Mmcfe per day)*	67.1	83.4	41.4	31.2	72.6	11.0	**234.1**
Reserve Life Index *(In years)* (1)	31.8	10.7	18.0	18.1	18.0	8.9	**18.9**
Gross Wells	3,178	685	677	778	1,455	38	**5,356**
Net Wells (2)	2,962.2	464.1	302.0	541.8	843.8	13.4	**4,283.5**
Percent Wells Operated *(Gross)*	97.1%	73.3%	50.2%	77.8%	64.9%	55.3%	**85.0%**

(1) *Reserve Life Index is equal to year-end reserves divided by annual production.*

(2) *The term net as used in net acreage or net production throughout this document refers to amounts that include only acreage or production that is owned by us and produced to our interest, less royalties and production due others. Net wells represents our working interest share of each well.*

On September 29, 2006, we substantially completed the sale of our offshore portfolio and certain south Louisiana properties to Phoenix Exploration Company LP (Phoenix) for a gross sales price of $340.0 million. We received approximately $333.3 million in net proceeds from the sale. In addition to the net gain of $231.2 million ($144.5 million, net of tax) recorded in 2006, we recorded a net gain of $12.3 million ($7.7 million, net of tax) in the Consolidated Statement of Operations in 2007, which included cash proceeds of $5.8 million received in the first quarter of 2007, $2.1 million in purchase price adjustments and $4.4 million that had been deferred until legal title to certain properties could be assigned.

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 seven years. These properties are

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held for longer periods if production is established. We own leasehold rights on approximately 2.9 million gross acres. In addition, we own fee interest in approximately 0.2 million gross acres, primarily in West Virginia. Our ten largest fields, which are fields with 2.5% or greater of total company proved reserves, make up approximately 48% of total company proved reserves.

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EAST REGION

Our East region activities are concentrated primarily in West Virginia. This region is managed from our office in Charleston, West Virginia. In this region, our assets include a large acreage position, a high concentration of wells, natural gas gathering and pipeline systems, and storage capacity.

Capital and exploration expenditures for 2007 were $178.6 million, or 28% of our total 2007 capital and exploration expenditures, compared to $145.4 million for 2006, or 27% of our total 2006 capital and exploration expenditures. Of the total company year-over-year increase in capital and exploration expenditures, 23% was attributable to an increase in the East region spending. For 2008, we have budgeted approximately $189 million for capital and exploration expenditures in the region.

At December 31, 2007, we had 3,178 wells (2,962.2 net), of which 3,085 wells are operated by us. There are multiple producing intervals that include the Big Lime, Weir, Berea and Devonian Shale formations at depths primarily ranging from 1,000 to 9,500 feet, with an average depth of approximately 4,000 feet. Average net daily production in 2007 was 67.1 Mmcfe. Natural gas and crude oil/condensate/NGL production for 2007 was 24.4 Bcf and 26 Mbbls, respectively.

While natural gas production volumes from East reservoirs are relatively low on a per-well basis compared to other areas of the United States, the productive life of East region reserves is relatively long. At December 31, 2007, we had 778.4 Bcfe of proved reserves (substantially all natural gas) in the East region, constituting 48% of our total proved reserves. Developed and undeveloped reserves made up 551.2 Bcfe and 227.2 Bcfe of the total proved reserves for the East region, respectively. While no properties are individually significant to our company as a whole, the Sissonville, Pineville, Logan-Holden-Dingess, Big Creek, Hernshaw-Bullcreek and Huff Creek fields in West Virginia are included in our ten largest fields and together contain approximately 29% of our total company proved equivalent reserves.

In 2007, we drilled 254 wells (244.6 net) in the East region, of which 250 wells (240.8 net) were development and extension wells. In 2008, we plan to drill approximately 265 wells (258.5 net), primarily in West Virginia, including the Sissonville, Pineville, Logan-Holden-Dingess, Big Creek, Huff Creek and Hernshaw-Bullcreek fields.

In 2007, we produced and marketed approximately 71 barrels of crude oil/condensate per day in the East region at market responsive prices.

Ancillary to our exploration, development and production operations, we operated a number of gas gathering and transmission pipeline systems, made up of approximately 3,100 miles of pipeline with interconnects to three interstate transmission systems, seven local distribution companies and numerous end users as of the end of 2007. The majority of our pipeline infrastructure in West Virginia 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 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 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 and the higher prices typically associated with winter natural gas sales, while maintaining production at a nearly constant rate throughout the year. The storage fields also enable us to increase for shorter intervals of time the volume of natural gas that we can deliver by more than 40% above the volume that we could deliver solely from our production in the East region. The pipeline systems and storage fields are fully integrated with our operations.

The principal markets for our East region natural gas are in the northeast United States. We sell natural gas to industrial customers, local distribution companies and gas marketers both on and off our pipeline and gathering system.

Approximately 70% of our natural gas sales volume in the East region is sold at index-based prices under contracts with a term of one year or greater. In addition, 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. Approximately two percent of East production is sold on fixed price contracts that typically renew annually.

GULF COAST REGION

Our development, exploitation, exploration and production activities in the Gulf Coast region are primarily concentrated in east and south Texas and north Louisiana. A regional office in Houston manages the operations. Principal producing intervals are in the Cotton Valley and James Lime formations in north Louisiana and east Texas and the Frio, Vicksburg and Wilcox formations in south Texas at depths ranging from 2,200 to 17,700 feet, with an average depth of approximately 10,800 feet.

Capital and exploration expenditures were $291.5 million for 2007, or 46% of our total 2007 capital and exploration expenditures, compared to $234.8 million for 2006, or 44% of our total 2006 capital and exploration expenditures. For 2008, we have budgeted approximately $209 million for capital and exploration expenditures in the region. Our 2008 Gulf Coast drilling program will emphasize activity primarily in east Texas.

We had 685 wells (464.1 net) in the Gulf Coast region as of December 31, 2007, of which 502 wells are operated by us. Average daily production in 2007 was 83.4 Mmcfe. Natural gas and crude oil/condensate/NGL production for 2007 was 26.8 Bcf and 606 Mbbls, respectively.

At December 31, 2007, we had 324.2 Bcfe of proved reserves (89% natural gas) in the Gulf Coast region, which represented 20% of our total proved reserves. Developed and undeveloped reserves made up 207.9 Bcfe and 116.3 Bcfe of the total proved reserves for the Gulf Coast region, respectively. While no properties are individually significant to our company as a whole, the Minden field in east Texas is included in our ten largest fields based on percentage of our total company proved equivalent reserves.

In 2007, we drilled 92 wells (71.0 net) in the Gulf Coast region, of which 87 wells (66.5 net) were development and extension wells. In 2008, we plan to drill 69 wells (51.3 net), primarily in east Texas, including the Minden, County Line and Trawick fields.

Our principal markets for Gulf Coast region natural gas are in the industrialized Gulf Coast area and the northeast United States. We sell natural gas to intrastate pipelines, natural gas processors and marketing companies. Currently, approximately 50% of our natural gas sales volumes in the Gulf Coast region are sold at index-based prices under contracts with terms of one to three years. The remaining 50% of our sales volumes are sold at index-based prices under short-term agreements. The Gulf Coast properties are connected to various processing plants in Texas and Louisiana with multiple interstate and intrastate deliveries, affording us access to multiple markets.

In 2007, we produced and marketed approximately 1,659 barrels of crude oil/condensate per day in the Gulf Coast region at market responsive prices.

WEST REGION

Our activities in the West region, which is comprised of the Rocky Mountains and Mid-Continent areas, are managed by a regional office in Denver, Colorado. At December 31, 2007, we had 477.5 Bcfe of proved reserves (96% natural gas) in the West region, constituting 30% of our total proved reserves. Developed and undeveloped

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reserves made up 384.4 Bcfe and 93.1 Bcfe of the total proved reserves for the West region, respectively. While no properties are individually significant to our company as a whole, the Mocane-Laverne field in Oklahoma in the Mid-Continent area and the Lincoln Road and Cow Hollow fields in Wyoming in the Rocky Mountain area are included within our ten largest fields and together contain approximately 10% of our total company proved equivalent reserves.

Our principal markets for West region natural gas are in the northwest and midwest United States. We sell natural gas to power generators, natural gas processors, local distribution companies, industrial customers and marketing companies. Currently, approximately 90% of our natural gas production in the West region is sold primarily under contracts with a term of one to three years at index-based prices. Another nine percent of the natural gas production is sold under short-term arrangements at index-based prices, and the remaining one percent is sold under certain fixed-price contracts. The West region properties are connected to the majority of the midwest and northwest interstate and intrastate pipelines, affording us access to multiple markets.

In 2007, we produced and marketed approximately 476 barrels of crude oil/condensate per day in the West region at market responsive prices.

Rocky Mountains

Activities in the Rocky Mountains are concentrated in the Green River and Washakie Basins in Wyoming and Paradox Basin in Colorado. At December 31, 2007, we had 271.6 Bcfe of proved reserves (96% natural gas) in the Rocky Mountains area, or 17% of our total proved reserves.

Capital and exploration expenditures in the Rocky Mountains were $54.7 million for 2007, or nine percent of our total 2007 capital and exploration expenditures, compared to $66.2 million for 2006, or 12% of our total 2006 capital and exploration expenditures. For 2008, we have budgeted approximately $23 million for capital and exploration expenditures in the area.

We had 677 wells (302.0 net) in the Rocky Mountains area as of December 31, 2007, of which 340 wells are operated by us. Principal producing intervals in the Rocky Mountains area are in the Almond, Frontier, Dakota and Honaker Trail formations at depths ranging from 4,200 to 14,375 feet, with an average depth of approximately 10,900 feet. Average net daily production in the Rocky Mountains during 2007 was 41.4 Mmcfe. Natural gas and crude oil/condensate/NGL production for 2007 was 14.4 Bcf and 114 Mbbls, respectively.

In 2007, we drilled 49 wells (26.2 net) in the Rocky Mountains, of which 47 wells (25.0 net) were development wells. In 2008, we plan to drill 16 wells (6.8 net), primarily in Wyoming, including the Cow Hollow and Lincoln Road fields.

Mid-Continent

Our Mid-Continent activities are concentrated in the Anadarko Basin in southwest Kansas, Oklahoma and the panhandle of Texas. At December 31, 2007, we had 205.9 Bcfe of proved reserves (97% natural gas) in the Mid-Continent area, or 14% of our total proved reserves.

Capital and exploration expenditures were $54.5 million for 2007, or eight percent of our total 2007 capital and exploration expenditures, compared to $39.8 million for 2006, or seven percent of our total 2006 capital and exploration expenditures. For 2008, we have budgeted approximately $56 million for capital and exploration expenditures in the area.

As of December 31, 2007, we had 778 wells (541.8 net) in the Mid-Continent area, of which 605 wells are operated by us. Principal producing intervals in the Mid-Continent are in the Chase, Morrow and Chester formations at depths ranging from 2,200 to 17,500 feet, with an average depth of approximately 7,050 feet. Average net daily production in 2007 was 31.2 Mmcfe. Natural gas and crude oil/condensate/NGL production for 2007 was 11.0 Bcf and 66 Mbbls, respectively.

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In 2007, we drilled 56 wells (43.9 net) in the Mid-Continent, all of which were development wells. In 2008, we plan to drill 66 wells (48.0 net), primarily in Oklahoma, including the Mocane-Laverne field.

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CANADA REGION

Our activities in the Canada region are managed by a regional office in Calgary, Alberta. Our Canadian exploration, development and producing activities are concentrated in the Province of Alberta. At December 31, 2007, we had 35.8 Bcfe of proved reserves (97% natural gas) in the Canada region, constituting two percent of our total proved reserves. Developed and undeveloped reserves made up 32.6 Bcfe and 3.2 Bcfe of the total proved reserves for the Canada region, respectively. No properties in the Canada region are individually significant to our company as a whole. The largest field in this region is the Hinton field in Alberta, which is not included in our ten largest fields.

Capital and exploration expenditures in Canada were $55.1 million for 2007, or nine percent of our total 2007 capital and exploration expenditures, compared to $49.0 million for 2006, or nine percent of our total 2006 capital and exploration expenditures. For 2008, we have budgeted approximately $13 million for capital and exploration expenditures in the area.

We had 38 wells (13.4 net) in the Canada region as of December 31, 2007, of which 21 wells are operated by us. Principal producing intervals in the Canada region are in the Falher, Bluesky, Cadomin, Dunvegan and the Mountain Park formations at depths ranging from 8,500 to 14,500 feet, with an average depth of approximately 10,950 feet. Average net daily production in Canada during 2007 was 11.0 Mmcfe. Natural gas and crude oil/condensate/NGL production for 2007 was 3.9 Bcf and 18 Mbbls, respectively.

In 2007, we drilled 10 wells (5.2 net) in Canada, of which 8 wells (4.0 net) were development and extension wells. In 2008, we plan to drill 3 wells (1.3 net) in various fields in Alberta.

Our principal markets for Canada natural gas are in western Alberta. We sell natural gas to gas marketers. Currently, all of our natural gas production in Canada is sold primarily under contracts with a term of one year at index-based prices. The Canadian properties are connected to the major interstate pipelines.

In 2007, we produced and marketed approximately 48 barrels of crude oil/condensate per day in the Canada region at market responsive prices.

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 in all of our regions. While there are many different types of derivatives available, in 2007 we employed natural gas price collar and swap agreements and crude oil price collar agreements for portions of our 2007 and 2008 production to attempt to manage price risk more effectively. 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 is below the floor. The price swaps call for payments to, or receipts from, counterparties based on whether the market price of natural gas for the period is greater or less than the fixed price established for that period when the swap is put in place. In 2006 and 2005, we also employed natural gas and crude oil price collar agreements. Additionally, in 2005, we employed natural gas price swap agreements. At December 31, 2007, we have natural gas price collar and swap arrangements and crude oil price collar arrangements in place for 2008.

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.

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RESERVES

Current Reserves

The following table presents our estimated proved reserves at December 31, 2007.

	Natural Gas *(Mmcf)*			**Liquids [1] *(Mbbl)***			**Total [2] *(Mmcfe)***		
	Developed	**Undeveloped**	**Total**	**Developed**	**Undeveloped**	**Total**	**Developed**	**Undeveloped**	**Total**
East	548,762	227,218	775,980	404		404	551,187	227,218	778,405
Gulf Coast	185,243	104,770	290,013	3,778	1,917	5,695	207,911	116,273	324,184
Rocky Mountains	196,543	63,100	259,643	1,668	317	1,985	206,548	65,000	271,548
Mid-Continent	171,819	27,869	199,688	1,001	41	1,042	177,825	28,118	205,943
Canada	31,570	3,059	34,629	175	27	202	32,620	3,219	35,839
Total	**1,133,937**	**426,016**	**1,559,953**	**7,026**	**2,302**	**9,328**	**1,176,091**	**439,828**	**1,615,919**

(1) *Liquids include crude oil, condensate and natural gas liquids.*

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

The proved reserve estimates presented here were prepared by our petroleum engineering staff and reviewed by Miller and Lents, Ltd., independent petroleum engineers. Miller and Lents 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; we used appropriate engineering, geologic and evaluation principles and techniques in accordance with practices generally accepted in the petroleum industry in making our estimates and projections and our total proved reserves are reasonable. For additional information regarding estimates of proved reserves, the review of such estimates by Miller 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 review letter by Miller and Lents, Ltd. has been filed as an exhibit to this Form 10-K. Our estimates of proved reserves in the table above are consistent with those filed by us with other federal agencies. During 2007, we filed estimates of our oil and gas reserves for the year 2006 with the Department of Energy. These estimates differ by 5 percent or less from the reserve data presented. Our reserves are sensitive to natural gas and crude oil sales prices and their effect on economic producing rates. Our reserves are based on oil and gas index prices in effect on the last day of December 2007. If we had considered the impact of our hedging activities, which were in a receivable position at December 31, 2007, in our proved reserves, there would not have been any significant effect.

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.

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Historical Reserves

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

	Natural Gas *(Mmcf)*	Oil & Liquids *(Mbbl)*	Total *(Mmcfe)* [1]
December 31, 2004	1,134,081	11,384	1,202,383
Revision of Prior Estimates	(1,543)	1,073	4,892
Extensions, Discoveries and Other Additions	185,884	334	187,891
Production	(73,879)	(1,747)	(84,361)
Purchases of Reserves in Place	17,567	419	20,083
Sales of Reserves in Place	(14)		(14)
December 31, 2005	1,262,096	11,463	1,330,874
Revision of Prior Estimates [2]	(17,675)	673	(13,640)
Extensions, Discoveries and Other Additions	246,197	1,066	252,594
Production	(79,722)	(1,415)	(88,212)
Purchases of Reserves in Place	1,946	38	2,176
Sales of Reserves in Place	(44,549)	(3,852)	(67,663)
December 31, 2006	1,368,293	7,973	1,416,129
Revision of Prior Estimates	2,604	771	7,228
Extensions, Discoveries and Other Additions	265,830	1,381	274,114
Production	(80,475)	(830)	(85,451)
Purchases of Reserves in Place	3,701	33	3,899
Sales of Reserves in Place			
December 31, 2007	**1,559,953**	**9,328**	**1,615,919**
Proved Developed Reserves			
December 31, 2004	857,834	8,652	909,747
December 31, 2005	944,897	9,127	999,661
December 31, 2006	996,850	5,895	1,032,222
December 31, 2007	**1,133,937**	**7,026**	**1,176,091**

(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) *The majority of the revisions were the result of the decrease in the natural gas price on December 31, 2006 from the price on December 31, 2005.*

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Volumes and Prices: Production Costs

The following table presents regional historical information about our net wellhead sales volume for natural gas and crude oil (including condensate and natural gas liquids), produced natural gas and crude oil realized sales prices, and production costs per equivalent.

	Year Ended December 31,		
	2007	**2006**	**2005**
Net Wellhead Sales Volume			
Natural Gas *(Bcf)*			
East	**24.4**	23.5	21.4
Gulf Coast	**26.8**	30.0	28.1
West	**25.4**	23.6	23.2
Canada	**3.9**	2.6	1.2
Crude/Condensate/Ngl *(Mbbl)*			
East	**26**	24	27
Gulf Coast	**606**	1,164	1,530
West	**180**	214	172
Canada	**18**	13	18
Produced Natural Gas Sales Price *($/Mcf)* [(1)]			
East	**$ 7.78**	$ 7.99	$ 8.02
Gulf Coast	**8.03**	7.37	6.38
West	**6.13**	6.05	6.00
Canada	**5.47**	6.18	6.79
Weighted Average	**7.23**	7.13	6.74
Produced Crude/Condensate Sales Price *($/Bbl)* [(1)]			
East	**$ 66.97**	$ 62.03	$ 53.84
Gulf Coast	**67.17**	65.44	42.81
West	**67.86**	63.36	55.37
Canada	**59.96**	60.55	43.39
Weighted Average	**67.16**	65.03	44.19
Production Costs *($/Mcfe)* [(2)]			
East	**$ 1.37**	$ 1.12	$ 1.09
Gulf Coast	**1.44**	1.37	1.14
West	**1.27**	1.34	1.36
Canada	**0.84**	0.84	1.07
Weighted Average	**1.36**	1.31	1.23

(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, transportation and storage). Includes realized impact of derivative instruments.*

(2) *Production costs include direct lifting costs (labor, repairs and maintenance, materials and supplies), the costs of administration of production offices, insurance and property and severance taxes, but is exclusive of depreciation and depletion applicable to capitalized lease acquisition, exploration and development expenditures.*

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Acreage

The following tables summarize our gross and net developed and undeveloped leasehold and mineral acreage at December 31, 2007. 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 by State						
Alabama	0	0	5,391	3,965	5,391	3,965
Arkansas	1,981	425	0	0	1,981	425
Colorado	16,268	14,053	200,334	128,450	216,602	142,503
Kansas	29,387	28,065	0	160	29,387	28,225
Louisiana	8,247	6,088	20,069	19,197	28,316	25,285
Mississippi	0	0	405,731	263,605	405,731	263,605
Montana	397	210	9,031	8,654	9,428	8,864
New York	2,379	961	621	256	3,000	1,217
Ohio	6,260	2,384	21,405	20,216	27,665	22,600
Oklahoma	184,447	129,436	30,902	23,882	215,349	153,318
Pennsylvania	111,496	63,549	88,932	88,484	200,428	152,033
Texas	111,866	79,605	68,970	49,727	180,836	129,332
Utah	2,820	1,609	179,137	94,436	181,957	96,045
Virginia	7,106	5,010	2,773	1,689	9,879	6,699
West Virginia	597,793	564,969	266,953	244,435	864,746	809,404
Wyoming	139,103	72,002	221,772	127,374	360,875	199,376
Total	**1,219,550**	**968,366**	**1,522,021**	**1,074,530**	**2,741,571**	**2,042,896**
Mineral Fee Acreage by State						
Colorado	0	0	2,899	271	2,899	271
Kansas	160	128	0	0	160	128
Montana	0	0	589	75	589	75
New York	0	0	6,545	1,353	6,545	1,353
Oklahoma	16,580	13,979	730	179	17,310	14,158
Pennsylvania	524	524	1,573	502	2,097	1,026
Texas	207	135	1,012	511	1,219	646
Virginia	17,817	17,817	100	34	17,917	17,851
West Virginia	98,162	79,490	50,896	49,669	149,058	129,159
Total	**133,450**	**112,073**	**64,344**	**52,594**	**197,794**	**164,667**
Aggregate Total	**1,353,000**	**1,080,439**	**1,586,365**	**1,127,124**	**2,939,365**	**2,207,563**

	Developed		Undeveloped		Total	
	Gross	Net	Gross	Net	Gross	Net
Canada Leasehold Acreage by Province						
Alberta	14,240	6,917	102,984	35,110	117,224	42,027
British Columbia	700	280	11,988	4,730	12,688	5,010
Saskatchewan	0	0	4,549	1,365	4,549	1,365
Total	**14,940**	**7,197**	**119,521**	**41,205**	**134,461**	**48,402**

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Total Net Leasehold Acreage by Region of Operation

	Developed	Undeveloped	Total
East	636,873	355,080	991,953
Gulf Coast	58,841	336,366	395,207
West	272,652	383,084	655,736
Canada	7,197	41,205	48,402
Total	**975,563**	**1,115,735**	**2,091,298**

Total Net Undeveloped Acreage Expiration by Region of Operation

The following table presents our net undeveloped acreage expiring over the next three years by operating region as of December 31, 2007. The figures below assume no future successful development or renewal of undeveloped acreage.

	2008	2009	2010
East	47,435	18,917	35,325
Gulf Coast	33,605	65,970	162,843
West	87,181	38,556	65,197
Canada	13,975	4,656	
Total	**182,196**	**128,099**	**263,365**

Well Summary

The following table presents our ownership at December 31, 2007, in productive natural gas and oil wells in the East region (consisting of various fields located in West Virginia, Virginia and Ohio), in the Gulf Coast region (consisting primarily of various fields located in Louisiana and Texas), in the West region (consisting of various fields located in Oklahoma, Kansas, Colorado, Utah and Wyoming) and in the Canada region (consisting of various fields located in the Province of Alberta). This summary includes natural gas and oil wells in which we have a working interest.

	Natural Gas		Oil		Total [1]	
	Gross	Net	Gross	Net	Gross	Net
East	3,153	2,950.2	25	12.0	3,178	2,962.2
Gulf Coast	567	356.3	118	107.8	685	464.1
West	1,400	810.6	55	33.2	1,455	843.8
Canada	37	12.9	1	0.5	38	13.4
Total	**5,157**	**4,130.0**	**199**	**153.5**	**5,356**	**4,283.5**

(1) *Total does not include service wells of 54 (51.6 net).*

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Drilling Activity

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

	Year Ended December 31, 2007									
	East		Gulf Coast		West		Canada		Total	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Development Wells										
Successful	248	238.8	80	61.0	96	63.1	5	2.8	**429**	**365.7**
Dry	1	1.0	3	2.5	7	5.8	0	0.0	**11**	**9.3**
Extension Wells										
Successful	1	1.0	4	3.0	0	0.0	3	1.2	**8**	**5.2**
Dry	0	0.0	0	0.0	0	0.0	0	0.0	**0**	**0.0**
Exploratory Wells										
Successful	3	2.8	1	0.5	0	0.0	2	1.2	**6**	**4.5**
Dry	1	1.0	4	4.0	2	1.2	0	0.0	**7**	**6.2**
Total	**254**	**244.6**	**92**	**71.0**	**105**	**70.1**	**10**	**5.2**	**461**	**390.9**
Wells Acquired	0	0.0	1	0.9	1	1.0	0	0.0	**2**	**1.9**
Wells in Progress at End of Year	2	2.0	9	5.2	2	1.1	1	0.2	**14**	