SOUTHWESTERN ENERGY CO
Form 10-K
February 25, 2010

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

Form 10-K

[X] Annual Report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934
For the fiscal year ended December 31, 2009
Commission file number 1-08246

Southwestern Energy Company
(Exact name of registrant as specified in its charter)

Delaware	**71-0205415**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
2350 North Sam Houston Parkway East, Suite 125,	
Houston, Texas	**77032**
(Address of principal executive offices)	(Zip Code)

(281) 618-4700
(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 $0.01 (including associated stock purchase rights)	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. Yesx Noo

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 Nox

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yesx Noo

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405 of this chapter) 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. o

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.

Large accelerated filer x Accelerated filer o Non-accelerated filer o Smaller reporting company o

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

The aggregate market value of the voting stock held by non-affiliates of the registrant was $13,121,603,390 based on the New York Stock Exchange Composite Transactions closing price on June 30, 2009, of $38.85. For purposes of this calculation, the registrant has assumed that its directors and executive officers are affiliates.

As of February 23, 2010, the number of outstanding shares of the registrant s Common Stock, par value $0.01, was 346,087,780.

Document Incorporated by Reference

Portions of the registrant s definitive proxy statement to be filed with respect to the annual meeting of stockholders to be held on or about May 18, 2010 are incorporated by reference into Part III of this Form 10-K.

SOUTHWESTERN ENERGY COMPANY
ANNUAL REPORT ON FORM 10-K
For Fiscal Year Ended December 31, 2009

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This Annual Report on Form 10-K includes certain statements that may be deemed to be forward-looking within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934, or the Exchange Act. We refer you to Risk Factors in Item 1A of Part I and to Management s Discussion and Analysis of Financial Condition and Results of Operations Cautionary Statement about Forward-Looking Statements in Item 7 of Part II of this Form 10-K for a discussion of factors that could cause actual results to differ materially from any such forward-looking statements. The electronic version of this Annual Report on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and amendments to those forms filed or furnished pursuant to Section 13(a) or 15(d) of the Exchange Act are available free of charge as soon as reasonably practicable after they are filed with the Securities and Exchange Commission, or SEC, on our website at www.swn.com. Our corporate governance guidelines and the charters of the Audit, Compensation, Nominating and Governance and Retirement Committees of our Board of Directors are available on our website, and are available in print free of charge to any stockholder upon request.

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ITEM 1. BUSINESS

Southwestern Energy Company is an independent energy company engaged in natural gas and crude oil exploration, development and production (E&P). We are also focused on creating and capturing additional value through our natural gas gathering and marketing businesses, which we refer to as Midstream Services.

Exploration and Production - Our primary business is the exploration for and production of natural gas within the United States, with our current operations being principally focused on development of an unconventional gas reservoir located on the Arkansas side of the Arkoma Basin, which we refer to as the Fayetteville Shale play. We are also actively engaged in exploration and production activities in Oklahoma, Texas and Pennsylvania. We conduct our exploration and production operations through our wholly-owned subsidiaries, SEECO, Inc., or SEECO, and Southwestern Energy Production Company, or SEPCO. SEECO operates exclusively in Arkansas where it holds a large base of both developed and undeveloped gas reserves, and conducts the Fayetteville Shale drilling program and the conventional Arkoma Basin drilling program in the Arkoma Basin. SEPCO conducts development drilling and exploration programs in the Oklahoma portion of the Arkoma Basin as well as in Texas and Pennsylvania. DeSoto Drilling, Inc., or DDI, a wholly-owned subsidiary of SEPCO, operates drilling rigs in the Fayetteville Shale play and in East Texas.

Midstream Services - We engage in gas gathering activities in Arkansas and Texas through our gathering subsidiaries, DeSoto Gathering Company, L.L.C., which we refer to as DeSoto Gathering, and Angelina Gathering Company, L.L.C., which we refer to as Angelina Gathering. DeSoto Gathering and Angelina Gathering primarily support our E&P operations and generate revenue from gathering fees associated with the transportation of our and third party gas to market. Our gas marketing subsidiary, Southwestern Energy Services Company, or SES, captures downstream opportunities which arise through marketing and transportation activity of the gas produced in our E&P operations.

The vast majority of our operating income and earnings before interest, taxes, depreciation, depletion and amortization, or EBITDA, is derived from our E&P business. In 2009, absent our $907.8 million, or $558.3 million net of taxes, non-cash ceiling test impairment of our natural gas and oil properties, 86% of our operating income and 90% of our EBITDA were generated from our E&P business, compared to 92% of our operating income and 89% of our EBITDA in 2008 and 94% of our operating income and 95% of our EBITDA in 2007. In 2009, 14% of our operating income, absent the non-cash ceiling test impairment of our natural gas and oil properties, and 10% of our EBITDA were generated from Midstream Services, compared to 7% of our operating income and 5% of our EBITDA in 2008 and 3% of our operating income and 3% of our EBITDA in 2007. In 2008 and 2007, the remainder of our EBITDA was generated from our Gas Distribution business which was sold effective July 1, 2008. EBITDA is a non-GAAP measure. We refer you to Business Other Items Reconciliation of Non-GAAP Measures in Item 1 of Part I of this Form 10-K for a table that reconciles EBITDA to net income (loss) attributable to Southwestern Energy.

Our Business Strategy

We are focused on providing long-term growth in the net asset value of our business. In our E&P business, we prepare an economic analysis for each investment opportunity based upon the expected present value added for each dollar to be invested, which we refer to as Present Value Index, or PVI. The PVI of the future expected cash flows for each project is determined using a 10% discount rate. We target creating at least $1.30 of discounted pre-tax PVI for each dollar we invest in our E&P projects. Our actual PVI results are utilized to help determine the allocation of our future capital investments. The key elements of our business strategy are:

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Exploit and Develop Our Position in the Fayetteville Shale. We seek to maximize the value of our significant acreage position in the Fayetteville Shale play, which we believe will continue to provide significant production and reserve growth. We intend to further develop our acreage position and improve our well results through the use of advanced technologies and detailed technical analysis of our properties. During 2009, primarily as a result of the economic recession, natural gas prices fell to their lowest levels over the last 7 years and if natural gas prices rebound in 2010 we could increase our planned investments and accelerate the development of our Fayetteville Shale play by utilizing additional drilling rigs.

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Maximize Efficiency through Economies of Scale. In our key operating areas, the concentration of our properties allows us to achieve economies of scale that result in lower costs. In our Fayetteville Shale play, we have achieved significant cost savings by operating a fleet of drilling rigs designed specifically for the play and from our other associated oilfield services. We seek to serve as the operator of the wells in which we have a significant interest. As the operator, we are better positioned to control the enhancing, drilling, completing and producing of wells and the marketing of production to minimize costs and maximize both production volumes and realized price.

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Enhancing Our Overall Returns through Expanding Our Midstream Operations. We seek to maximize profitability by exercising control over the delivery of natural gas from the areas where we have production. We have continued to design and improve our gas gathering infrastructure to better manage the physical movement of our production and the costs of our operations. As of December 31, 2009, we have invested approximately $548.9 million in the 1,137 mile gas gathering system built for our Fayetteville Shale play which was gathering approximately 1.3 Bcf per day at year-end. We intend to invest $270 million in our Midstream operations in 2010 to continue the expansion of our infrastructure. We have also been proactive in encouraging the construction of interstate pipelines to provide access to increase the markets in which we can sell our production. Our marketing subsidiary is a foundation shipper on two Fayetteville Shale pipeline projects that will provide access to the eastern and southern United States.

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Grow through New Exploration and Development Activities. We actively seek to find and develop new oil and gas plays with significant exploration and exploitation potential, which we refer to as New Ventures. New Ventures prospects are evaluated based on repeatability, multi-well potential and land availability as well as other criteria, and can be located both inside and outside of the United States. Our Fayetteville Shale play and our Marcellus Shale play began as a New Ventures projects in 2002 and 2007, respectively. As of December 31, 2009, we held 36,125 net undeveloped acres in New Ventures projects. In addition to New Ventures prospects, we also strategically seek to expand existing operations including joint ventures, farm-ins or farm-outs.

Recent Developments

Our planned capital investment program for 2010 is approximately $2.1 billion, which includes approximately $1.7 billion for our E&P segment, $270 million for our Midstream Services segment and $95 million for corporate and other purposes. Our 2010 capital program is expected to be primarily funded by our cash flow from operations and borrowings under our $1 billion revolving credit facility. The planned capital program for 2010 is flexible and can be adjusted to reflect market conditions. We will reevaluate our proposed investments as needed to take into account prevailing market conditions. Based on our capital program, we also announced our targeted 2010 gas and oil production of approximately 400 to 410 Bcfe, an increase of approximately 35% over our 2009 production (using the midpoint of targeted 2010 gas and oil production).

Exploration and Production

Overview

Our operations are primarily focused on the Fayetteville Shale, an unconventional reservoir located in the Arkoma Basin in Arkansas. We also conduct conventional operations in the Arkoma Basin where we target Atokan-age gas reservoirs. In addition to our Arkansas operations, we conduct both conventional and unconventional operations in East Texas primarily targeting the Cotton Valley, James Lime, Pettet, Haynesville Shale and Middle Bossier formations. We also hold a significant acreage position in northeastern Pennsylvania that we will begin drilling in 2010 targeting the Marcellus Shale. We continue to actively seek to develop both conventional and unconventional natural gas and oil resource plays with significant exploration and exploitation potential.

Our E&P segment recorded an operating loss of $157.7 million in 2009 as a result of the recognition of a $907.8 million, or $558.3 million net of taxes, non-cash ceiling test impairment of our natural gas and oil properties recorded for the three months ended March 31, 2009 due to a significant decline in natural gas prices. Our E&P segment recorded operating income of $813.5 million in 2008 and $358.1 million in 2007. The operating loss in 2009 was primarily due to the recognition of this ceiling test impairment, however, even without the write-down, operating income would have decreased, when compared to 2008 operating income, due to lower prices realized from the sale of our production and an increase in operating costs and expenses which more than offset the higher revenues realized from increased gas production. EBITDA from our E&P segment was $1.2 billion in 2009, compared to $1.2 billion in 2008 and $640.5 million in 2007. Our EBITDA in 2009 was approximately equal to 2008 as the impact of our increased production volumes was offset by decreased prices realized from the sale of our production and increased operating costs and expenses. The increases in both our operating income and EBITDA in 2008 when compared to 2007 were due to increased production volumes and higher realized prices, partially offset by increases in operating costs and expenses. EBITDA is a non-GAAP measure. We refer you to Business Other Items Reconciliation of Non-GAAP Measures in Item 1 of Part I of this Form 10-K for a reconciliation of EBITDA to net income (loss) attributable to Southwestern Energy.

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Our Proved Reserves

Our estimated proved natural gas and oil reserves were 3,657 Bcfe at year-end 2009, compared to 2,185 Bcfe at year-end 2008 and 1,450 Bcfe at year-end 2007. The overall increase in total estimated proved reserves in the past three years is primarily due to the development of the Fayetteville Shale play in Arkansas. In 2009, the SEC adopted a number of revisions to its oil and gas reporting disclosure requirements which are effective for this Form 10-K and accordingly, our estimated proved natural gas and oil reserves as of December 31, 2009 were valued utilizing the average prices in the 12-month period, which is defined, with certain exceptions, as the unweighted arithmetic average of the first-day-of-the-month price for each month within such period, of $3.87 per Mcf for natural gas and $57.65 per barrel for oil. The market prices for natural gas and crude oil used in calculating the value of our estimated proved natural gas and oil reserves for 2008 and 2007 were single day prices permitted to be used under the SEC s prior rules, which were $5.71 per Mcf for natural gas and $41.00 per barrel for oil at year-end 2008 and $6.80 per Mcf and $92.50 per barrel at year-end 2007.

The after-tax PV-10, or standardized measure of discounted future net cash flows relating to proved gas and oil reserve quantities, was $1.8 billion at year-end 2009, compared to $2.1 billion at year-end 2008 and $2.0 billion at year-end 2007. The decrease in the after-tax PV-10 value in 2009 is primarily due to a comparative decrease in the average 2009 price from the year-end 2008 gas price and higher operating and future development costs which were partially offset by an increase in reserves. Our proved reserves are almost entirely natural gas and as such the after-tax PV-10 measure is highly dependent upon the natural gas price used in the after-tax PV-10 calculation. The reconciling difference in after-tax PV-10 and pre-tax PV-10 (a non-GAAP measure which is reconciled in the 2009 Proved Reserves by Category and Summary Operating Data table below) is the discounted value of future income taxes on the estimated cash flows. Our year-end 2009 estimated proved reserves had a present value of estimated future net cash flows before income tax, or pre-tax PV-10, of $2.3 billion, compared to $3.0 billion at year-end 2008 and $2.6 billion at year-end 2007.

We believe that the pre-tax PV-10 value of the estimated cash flows related to our estimated proved reserves is a useful supplemental disclosure to the after-tax PV-10 value. While pre-tax PV-10 is based on prices, costs and discount factors that are comparable from company to company, the after-tax PV-10 is dependent on the unique tax situation of each individual company. We understand that securities analysts use pre-tax PV-10 as one measure of the value of a company s current proved reserves and to compare relative values among peer companies without regard to income taxes. We refer you to Note 4 in the consolidated financial statements for a discussion of our standardized measure of discounted future cash flows related to our proved natural gas and oil reserves, to the risk factor Although our estimated natural gas and oil reserve data is independently audited, our estimates may still prove to be inaccurate in Item 1A of Part I of this Form 10-K, and to Management s Discussion and Analysis of Financial Condition and Results of Operations Cautionary Statement about Forward-Looking Statements in Item 7 of Part II of this Form 10-K for a discussion of the risks inherent in utilization of standardized measures and estimated reserve data.

Approximately 100% of our year-end 2009 estimated proved reserves were natural gas and 54% were classified as proved developed, compared to 100% and 62%, respectively, in 2008 and 96% and 64%, respectively, in 2007. We operate approximately 94% of our reserves, based on the pre-tax PV-10 value of our proved developed producing reserves, and our reserve life index approximated 12.2 years at year-end 2009. Sales of natural gas production accounted for nearly 100% of total operating revenues for this segment in 2009, 97% in 2008 and 94% in 2007.

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The following table provides an overall and by category summary of our oil and gas reserves, as of fiscal year-end 2009 based on average fiscal year prices, and our well count, net acreage and PV-10 as of December 31, 2009 and sets forth 2009 annual information related to production and capital investments for each of our operating areas:

2009 PROVED RESERVES BY CATEGORY AND SUMMARY OPERATING DATA

	U.S. Exploitation					
	Fayetteville Shale Play	**East Texas**	**Arkoma Basin**	**Appalachia**	**New Ventures**	**Total**
Estimated Proved Reserves:						
Natural Gas (Bcf):						
Developed (Bcf)	1,501	280	190	2	-	**1,973**
Undeveloped (Bcf)	1,616	43	18	-	-	**1,677**
	3,117	323	208	2	-	**3,650**
Crude Oil (MMBbls):						

Developed (MMBbls)		-		1		-		-		-		**1**
Undeveloped (MMBbls)		-		-		-		-		-		**-**
		-		1		-		-		-		**1**
Total Proved Reserves (Bcfe)(1):												
Proved Developed (Bcfe)		1,501		287		190		2		-		**1,980**
Proved Undeveloped (Bcfe)		1,616		43		18		-		-		**1,677**
		3,117		330		208		2		-		**3,657**
Percent of Total		85%		9%		6%		-		-		**100%**
Percent Proved Developed		48%		87%		91%		100%		-		**54%**
Percent Proved Undeveloped		52%		13%		9%		-		-		**46%**
Production (Bcfe)		243.5		34.9		22.0		-		-		**300.4**
Capital Investments (millions)(2)	$	1,259	$	167	$	40	$	40	$	25	**$**	**1,531**
Total Gross Producing Wells		1,428		582		1,193		-		-		**3,203**
Total Net Producing Wells		993		449		583		-		-		**2,025**
Total Net Acreage		763,293(3)		115,199(4)		463,888(5)		149,317(6)		36,125		**1,527,822**
Net Undeveloped Acreage		394,538(3)		61,298(4)		278,927(5)		149,317(6)		36,125		**920,205**
PV-10:												
Pre-tax (millions)(7)	$	1,857	$	260	$	185	$	2	$	-	**$**	**2,304**

PV of taxes (millions)(7)	405	57	40	-	-	**502**
After-tax (millions)(7)	$ 1,452	$ 203	$ 145	$ 2	$ -	**$ 1,802**
Percent of Total	81%	11%	8%	-	-	**100%**
Percent Operated(8)	95%	97%	85%	-	-	**94%**

(1) We have no reserves from synthetic gas, synthetic oil or nonrenewable natural resources intended to be upgraded into synthetic gas or oil. Our proved reserves increased by 1,685 Bcfe as a result of our drilling program and net upward revisions of 92.9 Bcfe in 2009. Of the reserve additions, 757.6 Bcfe were proved developed and 927.5 Bcfe were proved undeveloped. We used standard engineering and geoscience methods, or a combination of methods, such as performance analysis, volumetric analysis and analogy to establish the appropriate level of certainty for reserve estimates from the material properties included in our total reserves.

(2) Our Total and Fayetteville Shale play capital investments exclude $35 million related to our sand facility and the purchase of drilling rig related and ancillary equipment.

(3) Assuming successful wells are not drilled and leases are not extended, leasehold expiring over the next three years will be 120,977 net acres in 2010, 23,722 net acres in 2011 and 34,231 net acres in 2012.

(4) Assuming successful wells are not drilled to develop the acreage and leases are not extended, leasehold expiring over the next three years will be 21,747 net acres in 2010, 24,594 net acres in 2011 and 2,334 net acres in 2012.

(5) Includes 123,442 net developed acres and 1,960 net undeveloped acres in the Arkoma Basin that are also within our Fayetteville Shale focus area but not included in the Fayetteville Shale acreage in the table above. Assuming successful wells are not drilled and leases are not extended, leasehold expiring over the next three years will be 32,434 net acres in 2010, 34,115 net acres in 2011 and 28,153 net acres in 2012.

(6) Assuming successful wells are not drilled to develop the acreage and leases are not extended, leasehold expiring over the next three years will be 1,475 net acres in 2010, 551 net acres in 2011 and 61,133 net acres in 2012.

(7) Pre-tax PV-10 (a non-GAAP measure) is one measure of the value of a company s proved reserves that we believe is used by securities analysts to compare relative values among peer companies without regard to income taxes. The reconciling difference in pre-tax PV-10 and the after-tax PV-10, or standardized measure, is the discounted value of future income taxes on the estimated cash flows from our proved oil and gas reserves.

(8) Based upon pre-tax PV-10 of proved developed producing properties.

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We refer you to Note 4 in our consolidated financial statements for a more detailed discussion of our proved natural gas and oil reserves as well as our standardized measure of discounted future cash flows related to our proved natural gas and oil reserves. We also refer you to the risk factor Although our estimated natural gas and oil reserve data is independently audited, our estimates may still prove to be inaccurate in Item 1A of Part I of this Form 10-K and to Management s Discussion and Analysis of Financial Condition and Results of Operations Cautionary Statement about Forward-Looking Statements in Item 7 of Part II of this Form 10-K for a discussion of the risks inherent in utilization of standardized measures and estimated reserve data.

Proved Undeveloped Reserves

As of December 31, 2009, we had 1,677 Bcfe of proved undeveloped reserves, none of which were proved undeveloped reserves that remain undeveloped for five years or more after initially being disclosed by us. During 2009, we invested $19.0 million in connection with converting 120.8 Bcfe of our proved undeveloped reserves as of December 31, 2008 into proved developed reserves and added 927.5 Bcfe of proved undeveloped reserve additions. Our 2009 proved undeveloped reserve additions are expected to be developed and to begin to generate cash inflows over the next five years.

The development of our proved undeveloped reserves will require us to make significant additional investments. We expect that the development costs for our proved undeveloped reserves of 1,677 Bcfe as of December 31, 2009, will require us to invest an additional $2.3 billion in order for those reserves to be brought to production. Our ability to make the necessary investments to generate these cash inflows is subject to factors that may be beyond our control. A significant decrease in price levels for an extended period of time could result in certain reserves no longer being economic to produce, leading to both lower proved reserves and cash flows. We refer you to the risk factors A substantial or extended decline in natural gas and oil prices would have a material adverse affect on us, We may have difficulty financing our planned capital investments, which could adversely affect our growth and Our future level of indebtedness and the terms of our financing arrangements may adversely affect operations and limit our growth in Item 1A of Part I of this Form 10-K and to Management s Discussion and Analysis of Financial Condition and Results of Operations Cautionary Statement about Forward-Looking Statements in Item 7 of Part II of this Form 10-K for a more detailed discussion of these factors and other risks.

Our Reserve Replacement

The ability of an E&P company to add new reserves to replace the reserves that are being depleted by its current production volumes is viewed by many investors as an indication of its long-term prospects. Reserves additions can be proved developed. The reserve replacement ratio, which we discuss below, is an important analytical measure used within the E&P industry by investors and peers to evaluate performance results. There are limitations as to the usefulness of this measure as it does not reflect the type of reserves or the cost of adding the reserves or indicate the potential value of the reserve additions. Our reserve replacement ratio has averaged over 500% during the last three years, primarily driven by increases in the reserves associated with our Fayetteville Shale play.

In 2009, we replaced 592% of our production volumes with an increase of 1,685 Bcfe of proved natural gas and oil reserves as a result of our drilling program and net upward revisions of 92.9 Bcfe. Of the reserve additions, 757.6 Bcfe were proved developed and 927.5 Bcfe were proved undeveloped. The upward reserve revisions during 2009 were primarily due to 384.8 Bcfe in upward revisions related to the improved performance of wells in our Fayetteville Shale play, partially offset by downward reserve revisions of 251.5 Bcfe due to a comparative decrease in the average gas price for 2009 as compared to year-end 2008. Additionally, we had downward performance revisions of 25.5 Bcfe and 15.1 Bcfe in our East Texas and conventional Arkoma Basin operating areas, respectively.

In 2008, our reserve replacement ratio was 523% (from reserve additions of 920.2 Bcfe primarily driven by our drilling program in the Fayetteville Shale play), including net upward revisions of 98.1 Bcfe. Of the 2008 reserve additions, 568.2 Bcfe were proved developed and 352.0 Bcfe were proved undeveloped. The improved performance of wells in our Fayetteville Shale play resulted in upward performance reserve revisions of 159.7 Bcf during 2008, which were partially offset by downward reserve revisions of 58.7 Bcfe due to a comparative decrease in year-end gas prices and performance revisions in our conventional Arkoma and East Texas operating areas. Additionally, our reserves decreased by 89.5 Bcfe as a result of our sale of oil and gas leases and wells in 2008.

In 2007, our reserve replacement ratio was 474% (from reserve additions of 507.9 Bcfe primarily driven by our drilling programs in the Fayetteville Shale play), including net upward reserve revisions of 31.0 Bcfe. Of the 2007 reserve additions, 281.2 Bcfe were proved developed and 226.7 Bcfe were proved undeveloped. The upward reserve revisions during 2007 were primarily due to improved performance of wells in our Fayetteville Shale play.

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For the period ending December 31, 2009, our three-year average reserve replacement ratio, including revisions, was 548%. Our reserve replacement ratio for 2009, excluding the effect of reserve revisions, was 561%, compared to 473% in 2008 and 447% in 2007. Excluding reserve revisions, our three-year average reserve replacement ratio is 512%.

Since 2005, the substantial majority of our reserve additions have been generated from our drilling program in the Fayetteville Shale play. We expect our drilling program in the Fayetteville Shale play to continue to be the primary source of our reserve additions in the future, however, our ability to add reserves depends upon many factors that are beyond our control. We refer you to the risk factors Our drilling plans for the Fayetteville Shale play are subject to change and Our exploration, development and drilling efforts and our operation of our wells may not be profitable or achieve our targeted returns in Item 1A of Part I of this Form 10-K and to Management s Discussion and Analysis of Financial Condition and Results of Operations Cautionary Statement about Forward-Looking Statements in Item 7 of Part II of this Form 10-K for a more detailed discussion of these factors and other risks.

Our Operations

Fayetteville Shale Play

Our Fayetteville Shale play is currently the primary focus of our E&P business. The Fayetteville Shale is a Mississippian-age unconventional gas reservoir located on the Arkansas side of the Arkoma Basin, ranging in thickness from 50 to 550 feet and ranging in depth from 1,500 to 6,500 feet. The Barnett Shale found in north Texas is an analogous reservoir. At December 31, 2009, we held leases for approximately 888,695 net acres in the play area (394,538 net undeveloped acres, 368,755 net developed acres held by Fayetteville Shale production, 123,442 net developed acres held by conventional production and an additional 1,960 net undeveloped acres in the traditional Fairway portion of the Arkoma Basin), compared to approximately 875,000 net acres at year-end 2008 and 906,700 net acres at year-end 2007. The increase in our acreage during 2009 was primarily due to additional acreage capture related to the integration of new sections and a small acquisition of producing properties in the play. The slight decrease in our net acreage during 2008 as compared to 2007 was primarily due to the sale of 55,631 acres to XTO Energy, Inc. in April 2008.

Approximately 3,117 Bcf of our reserves at year-end 2009 were attributable to our Fayetteville Shale play, compared to approximately 1,545 Bcf at year-end 2008 and 716 Bcf at year-end 2007. Gross production from our operated wells in the Fayetteville Shale play increased from approximately 720 MMcf per day at the beginning of 2009 to approximately 1,225 MMcf per day by year-end. Our net production from the Fayetteville Shale play was 243.5 Bcf in 2009, compared to 134.5 Bcf in 2008 and 53.5 Bcf in 2007. In 2010, our estimated production from the Fayetteville Shale play is expected to range between 344 and 352 Bcf.

Our leases generally require that we drill at least one producing well per governmental drilling unit (640 acres) in order to prevent our leases from expiring upon the expiration date. At year-end 2009, approximately 48% of our leasehold acreage was held by production, excluding our acreage in the traditional Fairway portion of the Arkoma Basin. We refer you to the risk factor If we fail to drill all of the wells that are necessary to hold our Fayetteville Shale acreage, the initial lease terms could expire, which would result in the loss of certain leasehold rights in Item 1A of Part I of this Form 10-K. Excluding our acreage in the traditional Fairway, our acreage position was obtained at an average cost of approximately $203 per acre with an average royalty interest of 15% and the undeveloped portion of our acreage had an average remaining lease term of 3 years. For more information about our acreage and well count, we refer you to Properties in Item 2 of Part I of this Form 10-K.

As of December 31, 2009, we had spud a total of 1,792 wells in the play, 1,437 of which were operated by us and 355 of which were outside-operated wells. Of the wells spud, 570 were in 2009, 604 were in 2008 and 415 were in 2007. Of the wells spud in 2009, 565 were designated as horizontal wells. At year-end 2009, 1,288 wells had been drilled and completed, including 1,201 horizontal wells. Of the 1,201 horizontal wells, 1,178 wells were fracture stimulated using either slickwater or crosslinked gel stimulation treatments, or a combination thereof.

During 2009, we continued to improve our drilling practices in the Fayetteville Shale play. Our horizontal wells had an average completed well cost of $2.9 million per well, average horizontal lateral length of 4,100 feet and average time to drill to total depth of 12 days from re-entry to re-entry. This compares to an average completed well cost of $3.0 million per well, average horizontal lateral length of 3,619 feet and average time to drill to total depth of 14 days from re-entry to re-entry during 2008. In 2007, our average completed well cost was $2.9 million per well with an average horizontal lateral length of 2,657 feet and average time to drill to total depth of 17 days from re-entry to re-entry. We also continued to improve our completion practices, as wells placed on production during 2009 averaged initial production rates of 3,478 Mcf per day, compared to average initial production rates of 2,777 and 1,687 Mcf per day in 2008 and 2007, respectively. Since 2007, improvements in our completion practices and longer lateral lengths have resulted in quarter-

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over-quarter improvements in average initial production rates of operated wells placed on production. During 2009, we placed 60 wells on production with initial production rates that exceeded 5.0 MMcf per day, including six wells that exceeded 6.0 MMcf per day and the play s highest rate well, the Arklan, Inc. 09-11 #4-32H located in Cleburne County, with an initial production rate of approximately 7.6 MMcf per day.

Beginning in late 2008 and continuing through 2009, we drilled a significant number of wells to test tighter well spacing. At December 31, 2009, we had placed over 300 wells on production that have well spacing of 700 feet or less, representing approximately 65-acre spacing or less, with encouraging results. In areas tested to date, we expect to drill between 10 and 12 wells per section in the Fayetteville Shale play, pending additional well data and analyses. We will continue to focus on optimizing the well spacing for the play and plan to test over 20 different pilot areas with well spacings that will range from 300 to 600 feet apart as part of our 2010 drilling program.

Our total proved net reserves booked in the play at year-end 2009 were 3,117 Bcf from a total of 2,675 locations, of which 1,428 were proved developed producing, 97 were proved developed non-producing and 1,150 were proved undeveloped. Of the 2,675 locations, 2,609 were horizontal. The average gross proved reserves for the undeveloped wells included in our year-end reserves was approximately 2.2 Bcf per well, up from 1.9 Bcf per well at year-end 2008 and 1.5 Bcf per well at year-end 2007. Total proved gas reserves booked in the play in 2008 totaled approximately 1,545 Bcf from a total of 1,508 locations, of which 882 were proved developed producing, 18 were proved developed non-producing and 608 were proved undeveloped. Total proved gas reserves booked in the play in 2007 totaled approximately 716 Bcf from a total of 935 locations, of which 497 were proved developed producing, 14 were proved developed non-producing and 424 were proved undeveloped. If the Fayetteville Shale play continues to be successfully developed, we expect a continued significant level of proved undeveloped reserves in the Fayetteville Shale play over the next few years.

In 2009, we invested approximately $1.3 billion in our Fayetteville Shale play, which included approximately $1.1 billion to spud 570 wells, 420 of which we operated. We increased our reserves in the Fayetteville Shale play by 1,815 Bcf, which included net upward reserve revisions of 238 Bcf due primarily to improved well performance which was partially offset by downward revisions due to lower prices. Included in our total capital investments in the play during 2009 was $40 million for acquisition of properties, $22 million for seismic and $106 million in capitalized costs and other expenses. At December 31, 2009, we had acquired approximately 1,324 square miles of 3-D seismic data, which provides us with seismic data on approximately 68% of our net acreage position in the Fayetteville Shale, excluding our acreage in the traditional Fairway portion of the Arkoma Basin. In 2008, we invested approximately $1.2 billion in our Fayetteville Shale play, which included $1.0 billion to spud 604 wells, $23 million for acquisition of properties, $61 million for seismic and $83 million in capitalized costs and other expenses. In 2007, we invested approximately $960 million in our Fayetteville Shale play, which included $789 million to spud 415 wells, $25 million for acquisition of properties, $97 million for 3-D seismic and $49 million in capitalized costs and other expenses.

In 2010, we plan to invest approximately $1.2 billion in our Fayetteville Shale play, which includes participating in approximately 650 to 680 gross wells, 475 to 500 of which are planned to be operated by us.

We believe that our Fayetteville Shale acreage continues to have significant development potential. Our strategy going forward is to increase our production through development drilling, increase the amount of acreage we hold by production and determine the economic viability of the undrilled portion of our acreage. Our drilling program with respect to our Fayetteville Shale play is flexible and will be impacted by a number of factors, including the results of our horizontal drilling efforts, our ability to determine the most effective and economic fracture stimulation methods and well spacing, the extent to which we can replicate the results of our most successful Fayetteville Shale wells in other Fayetteville Shale acreage and the natural gas commodity price environment. As we continue to gather data about the Fayetteville Shale, it is possible that additional information may cause us to alter our drilling schedule or determine that prospects in some portion of our acreage position should not be pursued at all. We refer you to the risk factor Our drilling plans for the Fayetteville Shale play are subject to change in Item 1A of Part I of this Form 10-K.

U.S. Exploitation

East Texas. We have been an active operator in East Texas since 2000, when we first began our activities in the area targeting the Cotton Valley sand formation with the purchase of the Overton Field, or Overton, in Smith County, Texas. We have expanded our activities to include additional opportunities at Overton as well as significant potential drilling targeting the James Lime, Pettet, Haynesville Shale and Middle Bossier formations.

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At December 31, 2009, we had approximately 330 Bcfe of reserves in East Texas, compared to 351 Bcfe at year-end 2008 and 353 Bcfe at year-end 2007. Our proved reserves have decreased over the past three years primarily due to our annual field production and downward reserve revisions resulting from comparative decreases in gas prices and negative performance revisions, which have more than offset our successful drilling in the James Lime and Haynesville Shale formations. In 2009, we invested approximately $167 million in East Texas and participated in 46 wells, of which 33 were successful and 13 were in progress at year-end, resulting in a 100% success rate and adding new reserves of 94 Bcfe. This area recorded net downward revisions of approximately 55.3 Bcfe primarily due to a comparative decrease in the average 2009 gas price from the 2008 year-end gas price and 25.5 Bcfe of negative performance revisions. Net production from East Texas was 34.9 Bcfe in 2009, compared to 31.6 Bcfe in 2008 and 29.9 Bcfe in 2007. Production has grown over the past three years primarily due to our successful drilling program in the James Lime formation which, combined with successful drilling in the Haynesville Shale in 2009, more than offset the natural production decline at Overton.

Our original interest in Overton (which was approximately 10,800 gross acres) was acquired in April 2000 for $6 million. Our wells in Overton produce from four Taylor series sands in the Cotton Valley formation at approximately 12,000 feet. At December 31, 2009, we held approximately 24,400 gross acres in Overton with an average working interest of 83% and an average net revenue interest of 67%. In 2009, we invested approximately $4 million to drill two wells at Overton, both of which were successful. Our proved reserves in Overton were 189 Bcfe at year-end 2009, compared to 273 Bcfe at year-end 2008 and 315 Bcfe at year-end 2007. Net production from Overton was 14.6 Bcfe in 2009, compared to 19.9 Bcfe in 2008 and 25.1 Bcfe in 2007. We expect our production and reserves from Overton to continue to decline due to the planned lack of significant investment in the field during 2010 and the natural production decline in existing wells.

Our Angelina River Trend properties, collectively referred to as Angelina, are concentrated in several separate development areas located primarily in four counties in East Texas targeting the Travis Peak, Haynesville Shale, James Lime, Pettet and Middle Bossier formations. At December 31, 2009, we held approximately 95,200 gross undeveloped acres and 40,200 gross developed acres at Angelina with an average working interest of 65% and an average net revenue interest of 50%. Our acreage position was obtained at an average cost of approximately $241 per acre and the undeveloped portion of our acreage has an average remaining lease term of 2 years. Our proved reserves in the Angelina area were 137 Bcfe at year-end 2009, compared to 74 Bcfe at year-end 2008 and 33 Bcfe at year-end 2007. Net production from our Angelina properties was 19.7 Bcfe in 2009, compared to 11.3 Bcfe in 2008 and 2.5 Bcfe in 2007.

In 2009, we invested approximately $143 million to drill 44 wells at Angelina, all of which were successful or in progress at December 31, 2009. Our 2009 drilling program was primarily focused on developing the James Lime formation in our Jebel prospect area located in Shelby County, Texas. We also successfully initiated drilling in the Haynesville Shale and Middle Bossier in Shelby and San Augustine Counties with the first horizontal well, the Red River 877 #1 located in Shelby County, production testing at 7.2 MMcf per day in the first quarter of 2009. We drilled four additional wells in the Haynesville Shale formation which production tested at 13.4 MMcf per day, 16.7 MMcf per day, 21.0 MMcf per day and 18.1 MMcf per day. Additionally, we completed our first well in the Middle Bossier formation which production tested at 11.3 MMcf per day. In total, we have approximately 42,300 net acres we believe are prospective for the Haynesville and Middle Bossier Shales and our average gross working interest is approximately 61%.

At December 31, 2009, we had participated in 77 James Lime horizontal wells, 51 of which we operated, including 8 wells which were in progress. Of those, 43 wells that we operated were placed on production at an average gross initial production rate of 9.8 MMcfe per day, resulting in net production from the James Lime of approximately 48 MMcf per day at December 31, 2009.

In 2010, we expect to invest approximately $230 million and participate in approximately 50 to 60 gross wells in East Texas, 22 to 27 of which will be operated. Of the wells planned in 2010, 21 to 26 wells will be targeting the Haynesville or Middle Bossier Shales and 29 to 34 will target the James Lime, Pettet or Cotton Valley formations.

Conventional Arkoma Basin. We have traditionally operated in a portion of the Arkoma Basin located in western Arkansas that we refer to as the Fairway. In recent years, we have expanded our activity in the Arkoma Basin to the south and east of the traditional Fairway area, primarily in the Ranger Anticline and Midway areas. We refer to our drilling program targeting stratigraphic Atokan-age objectives in Oklahoma and Arkansas as the conventional Arkoma drilling program.

At December 31, 2009, we had approximately 208 Bcf of reserves that were attributable to our conventional Arkoma properties, representing approximately 6% of our total reserves, compared to 281 Bcf at year-end 2008 and 304 Bcf at year-end 2007. Our proved reserves have declined over the past three years primarily due to lower capital

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investments in the area which were not sufficient to offset our annual field production and downward revisions due to comparative decreases in gas prices and negative performance revisions. In 2009, we invested approximately $40 million in our conventional Arkoma drilling program and participated in 20 wells, of which 15 were successful and 3 were in progress at year-end, resulting in an 88% success rate and adding new reserves of 14 Bcf. This area recorded net downward revisions of approximately 64 Bcf primarily due to a comparative decrease in the average 2009 price from the year-end 2008 gas price and negative performance revisions. Net production from our conventional Arkoma properties was 22.0 Bcf in 2009, compared to 24.4 Bcf in 2008 and 23.8 Bcf in 2007. Production decreased during 2009 primarily due to significantly lower capital investments in the area as compared to 2008 levels, while production increased in 2008 from 2007 as new production stemming from our 2008 drilling program more than offset the natural production decline from existing wells.

In 2010, we plan to invest approximately $25 million in our conventional Arkoma program and participate in approximately 15 to 20 wells.

Appalachia. We began leasing in northeastern Pennsylvania in 2007 in an effort to gain a position in the emerging Marcellus Shale play. At December 31, 2009, we had approximately 149,317 net acres in Pennsylvania under which we believe the Marcellus Shale is prospective. Our undeveloped acreage position as of December 31, 2009 had an average remaining lease term of 5 years, an average royalty interest of 13% and was obtained at an average cost of approximately $594 per acre. During 2009, we invested approximately $40 million in Pennsylvania, almost all of which was for acquisition of properties, including approximately 22,829 net acres in Lycoming County that was purchased for approximately $8.7 million, or $382 per acre. In 2008, we invested approximately $58 million in the Marcellus Shale play in Pennsylvania and drilled our first four wells (three vertical and one horizontal) on our acreage in Bradford and Susquehanna Counties, three of which have been production tested. In 2007, we invested approximately $17.5 million to purchase acreage in the Marcellus Shale play.

In 2010, we plan to invest approximately $145 million in Appalachia, which includes participating in a total of 35 to 40 wells, 21 to 24 of which will be operated.

New Ventures

We actively seek to find and develop new oil and gas plays with significant exploration and exploitation potential, which we refer to as New Ventures. We have been focusing on unconventional plays (including coalbed methane, shale gas and basin-centered gas) as well as determining the technological methods best suited to developing these plays, such as horizontal drilling and fracture stimulation techniques. New Ventures prospects are evaluated based on repeatability, multi-well potential and land availability as well as other criteria and may be located both inside and outside of the United States. At December 31, 2009, we held 36,125 net undeveloped acres in the United States outside of our core operating areas in connection with New Ventures prospects. This compares to 138,638 and 156,465 net undeveloped acres held at year-end 2008 and 2007, respectively, of which 114,738 and 88,000 net undeveloped acres, respectively, were in Pennsylvania where we are targeting the Marcellus Shale. The Marcellus Shale acreage was transferred to our U.S. Exploitation group in 2009 and is discussed in more detail in the paragraphs above.

In 2009, we invested approximately $25 million in our New Ventures program, compared to approximately $73 million invested in our New Ventures program in 2008 and approximately $42 million in 2007. Of the amounts invested during 2008 and 2007, approximately $58 million and $17.5 million, respectively, were invested in the Marcellus Shale play in Pennsylvania. In 2010, we plan to invest approximately $135 million in various unconventional, exploration and New Ventures projects.

Acquisitions and Divestitures

During 2009, we purchased approximately 22,829 net acres in Lycoming County, Pennsylvania, for approximately $8.7 million. Additionally, during 2009 we also purchased the oil and gas leases, wells and gathering equipment on approximately 16,980 net acres in the Fayetteville Shale play for approximately $4.0 million and sold the oil and gas leases, wells and gathering equipment in our Riverton coalbed methane project in Caldwell Parish, Louisiana, for approximately $4.1 million.

During 2008, we sold the oil and gas leases, wells and equipment that comprised our Permian Basin and onshore Texas Gulf Coast operating assets to various buyers for approximately $240 million in the aggregate. The sales included 95,700 net acres of leasehold, 69 Bcfe of proved reserves and approximately 16 MMcfe per day of production from the properties as of April 1, 2008.

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In 2008, we also sold certain oil and gas leases, wells and gathering equipment in our Fayetteville Shale play to XTO Energy, Inc. for approximately $518.3 million. The sale included 55,631 net acres of leasehold, 20 Bcf of proved reserves and approximately 10.5 MMcf per day of production from the Fayetteville Shale as of March 17, 2008.

There were no significant acquisitions or divestitures of gas and oil properties in 2007.

Capital Investments

During 2009, we invested a total of $1.6 billion in our E&P business and participated in drilling 636 wells, 419 of which were successful, 5 were dry and 212 were in progress at year-end. Of the 212 wells in progress at year-end, 196 were located in our Fayetteville Shale play. Our investments focused primarily on our active drilling programs in the Fayetteville Shale play, East Texas, Appalachia and the conventional Arkoma Basin, which accounted for 82%, 11%, 3% and 3% of our E&P capital investments in 2009, respectively. We invested approximately $1.3 billion in our Fayetteville Shale play, $167 million in East Texas, $40 million in Appalachia, $40 million in our conventional Arkoma Basin program and $25 million in New Ventures projects.

Of the $1.6 billion invested in 2009, approximately $1.3 billion was invested in exploratory and development drilling and workovers, $82 million for acquisition of properties, $32 million for seismic expenditures and $155 million in capitalized interest and expenses and other technology-related expenditures. Additionally, we invested approximately $35 million in our sand facility and drilling rig related and ancillary equipment. In 2008, we invested approximately $1.6 billion in our primary E&P business activities and participated in drilling 750 wells. Of the $1.6 billion invested in 2008, approximately $1.3 billion was invested in exploratory and development drilling and workovers, $83 million for acquisition of properties, $66 million for seismic expenditures and $118 million in capitalized interest and expenses and other technology-related expenditures. Additionally, we invested approximately $36 million in drilling rig related and ancillary equipment. In 2007, we invested approximately $1.4 billion in our primary E&P business activities and participated in drilling 653 wells. Of the $1.4 billion invested in 2007, approximately $1.1 billion was invested in exploratory and development drilling and workovers, $68 million for acquisition of properties, $100 million for seismic expenditures and $77 million in capitalized interest and expenses and other technology-related expenditures.

In 2010, we plan to invest approximately $1.7 billion in our E&P program and participate in drilling 750 to 800 gross wells, 520 to 555 of which are planned to be operated by us. The Fayetteville Shale play will be the primary focus of our capital investments, with planned investments of approximately $1.2 billion. Our planned 2010 capital investments also include approximately $230 million in East Texas, $145 million in Appalachia, $135 million in unconventional, exploration and New Ventures projects, $25 million in our conventional drilling program in the Arkoma Basin and $15 million for other E&P projects.

Of the $1.7 billion allocated to our 2010 E&P capital budget, approximately $1.3 billion (or 76%) will be invested in development and exploratory drilling, $25 million in seismic and other geological and geophysical expenditures, $180 million in acquisition of properties and $220 million in capitalized interest and expenses as well as equipment, facilities and technology-related expenditures. We refer you to Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources Capital Investments for additional discussion of the factors that could impact our planned capital investments in 2010.

Other Revenues

Other revenues and operating income for 2009 included gains of approximately $3.4 million related to the sale of gas-in-storage inventory and charges totaling $6.1 million primarily related to a $4.3 million non-cash impairment to reduce the current portion of our natural gas inventory to the lower of cost or market. Other revenues and operating income for 2008 and 2007 included gains of approximately $4.8 million and $6.4 million, respectively, related to the sale of gas-in-storage inventory.

Sales, Delivery Commitments and Customers

Sales. Our daily natural gas equivalent production averaged 823.1 MMcfe in 2009, compared to 533.1 MMcfe in 2008 and 311.1 MMcfe in 2007. Total natural gas equivalent production was 300.4 Bcfe in 2009, up from 194.6 Bcfe in 2008 and 113.6 Bcfe in 2007. Our natural gas production was 299.7 Bcf in 2009, compared to 192.3 Bcf in 2008 and 109.9 Bcf in 2007. The increase in production in 2009 resulted primarily from a 109.0 Bcf increase in production from the Fayetteville Shale play and an increase in our East Texas production, which more than offset a combined decrease in net production arising from decreased production from our Arkoma and other properties and the sale of our Permian Basin and Gulf Coast properties in 2008. The increase in production in 2008 resulted primarily from an 81.0 Bcf increase in

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production from the Fayetteville Shale play which combined with increases in our East Texas and Arkoma production to more than offset the decreases resulting from the oil and gas properties sold during 2008. We also produced 124,000 barrels of oil in 2009, compared to 385,000 barrels of oil in 2008 and 614,000 barrels of oil in 2007. Our oil production decreased during 2009 and 2008 primarily due to the sale of our Permian and Gulf Coast properties in 2008. For 2010, we are targeting total natural gas and crude oil production of approximately 400 to 410 Bcfe, which represents a growth rate of approximately 35% over our 2009 production volumes.