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-

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.

Sales of gas and oil production are conducted under contracts that reflect current prices and are subject to seasonal price swings. We are unable to predict changes in the market demand and price for natural gas, including changes that may be induced by the effects of weather on demand for our production.

We periodically enter into various hedging and other financial arrangements with respect to a portion of our projected natural gas and crude oil production in order to support certain desired levels of cash flow and to minimize the impact of price fluctuations. Our policies prohibit speculation with derivatives and limit swap agreements to counterparties with appropriate credit standings. At December 31, 2009, we had hedges in place on 66 Bcf, or approximately 16% of our targeted 2010 gas production, and 30 Bcf of our expected 2011 gas production. We intend to hedge additional future production volumes to the extent natural gas prices rise to levels that we believe will achieve certain desired levels of cash flow. We refer you to Item 7A of this Form 10-K, Quantitative and Qualitative Disclosures about Market Risks, for further information regarding our hedge position at December 31, 2009.

Including the effect of hedges, we realized an average wellhead price of $5.30 per Mcf for our natural gas production in 2009, compared to $7.52 per Mcf in 2008 and $6.80 per Mcf in 2007. Our hedging activities increased our average gas price $1.96 per Mcf in 2009, decreased our average price $0.21 per Mcf in 2008 and increased our average price $0.64 per Mcf in 2007. Our average oil price realized was $54.99 per barrel in 2009, compared to $107.18 per barrel in 2008 and $69.12 per barrel in 2007. None of our crude oil production was hedged during 2009, 2008 or 2007.

In recent years, locational differences in market prices for natural gas have been wider than historically experienced. Disregarding the impact of hedges, from 2005 through 2007, the average price received for our gas production was approximately $0.50 to $1.00 per Mcf lower than average NYMEX spot market prices primarily due to the locational market differentials. However, during 2009 and 2008, widening market differentials caused the difference in our annual average price received for our gas production to range from approximately $0.65 to $1.30 per Mcf lower than market prices. The discount was at its highest in late 2008, due to increased production in the Fayetteville Shale for which there was not sufficient transportation to other markets as a result of the delay in the completion of the Boardwalk Pipeline. Since the completion of the Boardwalk Pipeline, the locational differences in the market prices for our gas production has narrowed. Assuming a NYMEX commodity price for 2010 of $5.00 per Mcf of gas, the average price received for our gas production is expected to be approximately $0.10 to $0.20 per Mcf below the NYMEX Henry Hub index price, including the impact of our basis hedges. Our E&P segment receives a sales price for our natural gas at a discount to NYMEX spot prices due to locational basis differentials, while transportation charges and fuel charges also reduce the price received. In 2010, we expect to pay average third-party transportation charges in the range of $0.25 to $0.32 per Mcf and average fuel charges in the range of 0.25% to 1.00% of our sales price for natural gas.

Delivery Commitments. As of February 1, 2010, we had natural gas delivery commitments of 134 Bcf in 2010 and 38 Bcf in 2011 under existing agreements. These commitments require the delivery of natural gas in Arkansas and Texas. These amounts are well below our forecasted 2010 and anticipated 2011 production from our available reserves in our Fayetteville Shale and East Texas operations, which are not subject to any priorities or curtailments that may affect quantities delivered to our customers or any priority allocations or price limitations imposed by federal or state regulatory agencies, or any other factors beyond our control that may affect our ability to meet our contractual obligations other than those discussed in Item 1A. Risk Factors . We expect to be able to fulfill all of our short-term or long-term contractual obligations from available reserves from our own production, however, if we are unable to do so, we may have to purchase gas at market to fulfill our obligations. We may have to borrow funds to pay for these gas purchases and if we are unable to do so, our earnings could be adversely affected.

Customers. Our customers include major and small energy companies, utilities and industrial consumers of natural gas. During the years ended December 31, 2009, 2008 and 2007, no single third-party customer accounted for 10% or more of our consolidated revenues.

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Impact of Federal Regulation of Sales of Natural Gas and Oil

Historically, the sale of natural gas in interstate commerce has been regulated pursuant to the Natural Gas Act of 1938, or the NGA, the Natural Gas Policy Act of 1978, or the NGPA, and regulations promulgated thereunder by the Federal Energy Regulatory Commission, or the FERC. In 1989, Congress enacted the Natural Gas Wellhead Decontrol Act, or the Decontrol Act. The Decontrol Act removed all NGA and NGPA price and non-price controls affecting wellhead sales of natural gas effective January 1, 1993 and sales by producers of natural gas can be made at uncontrolled market prices.

The natural gas industry historically has been heavily regulated and from time to time proposals are introduced by Congress and the FERC and judicial decisions are rendered that impact the conduct of business in the natural gas industry. There can be no assurance that the less stringent regulatory approach pursued by the FERC and Congress will continue. We refer you to Other Items Environmental Matters and the risk factor We incur substantial costs to comply with government regulations, especially regulations relating to environmental protection, and could incur even greater costs in the future in Item 1A of Part I of this Form 10-K for a discussion of the impact of government regulation on our natural gas distribution business.

Competition

All phases of the oil and gas industry are highly competitive. We compete in the acquisition of properties, the search for and development of reserves, the production and sale of natural gas and oil and the securing of labor and equipment required to conduct our operations. Our competitors include major oil and gas companies, other independent oil and gas companies and individual producers and operators. Many of these competitors have financial and other resources that substantially exceed those available to us.

Competition in Arkansas has increased in recent years due largely to the development of improved access to interstate pipelines and our discovery of the Fayetteville Shale play. While improved intrastate and interstate pipeline transportation in Arkansas should increase our access to markets for our gas production, these markets will also be served by a number of other suppliers. Consequently, we will encounter competition that may affect both the price we receive and contract terms we must offer. Outside Arkansas, we are less established and face competition from a larger number of other producers.

Commencing in 1992, the FERC issued a series of orders (collectively, Order No. 636), which require interstate pipelines to provide transportation separately, or unbundled, from the pipelines sales of gas. Order No. 636 also requires pipelines to provide open-access transportation on a basis that is equal for all shippers. Although Order No. 636 does not directly regulate our activities, the FERC has stated that it intends for Order No. 636 to foster increased competition within all phases of the natural gas industry. Starting in 2000, the FERC issued a series of orders (collectively, Order No. 637), which imposed a number of additional reforms designed to enhance competition in natural gas markets. Among other things, Order No. 637 revised the FERC pricing policy by waiving price ceilings for short-term released capacity for a two-year period, and effected changes in FERC regulations relating to scheduling procedures, capacity segmentation, pipeline penalties, rights of first refusal and information reporting. The implementation of these orders has not had a material adverse effect on our results of operations to date.

We cannot predict whether and to what extent any market reforms initiated by the FERC or any new energy legislation will achieve the goal of increasing competition, lessening preferential treatment and enhancing transparency in markets in which our natural gas is sold. However, we do not believe that we will be disproportionately affected as compared to other natural gas producers and marketers by any action taken by the FERC or any other legislative body.

Midstream Services

Our Midstream Services segment is well-positioned to complement our E&P initiatives and to compete with other midstream providers for unaffiliated business. Our midstream assets support our E&P operations and are currently concentrated in our Fayetteville Shale play. We generate revenue from gathering fees associated with the transportation of natural gas to market and through the marketing of natural gas.

Our operating income from this segment was $122.6 million on revenues of $1.6 billion in 2009, compared to $62.3 million on revenues of $2.2 billion in 2008 and $13.2 million on revenues of $962.0 million in 2007. Revenues decreased in 2009 as increased gathering revenues and increased volumes marketed were more than offset by considerably lower gas prices. The increase in revenue in 2008 was largely attributable to increased gathering revenues, increased volumes marketed and higher gas prices. EBITDA generated by our Midstream Services segment was $141.9 million in

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2009, compared to $73.9 million in 2008 and $18.8 million in 2007. The increases in 2009 and 2008 operating income and EBITDA were primarily due to increased gathering revenues and marketing margins, partially offset by increased operating costs and expenses. We expect that the operating income and EBITDA of our Midstream Services segment will increase significantly over the next few years as we continue to develop our Fayetteville Shale acreage. 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.

Gas Gathering

We engage in gas gathering activities through our gathering subsidiaries, DeSoto Gathering and Angelina Gathering. DeSoto Gathering engages in gathering activities in Arkansas primarily related to the development of our Fayetteville Shale play. In 2009, we invested approximately $214.2 million related to these activities and had gathering revenues of $205.6 million, compared to $183.0 million invested and revenues of $114.9 million in 2008 and $107.4 million invested and $37.7 million in revenues in 2007.

DeSoto Gathering is rapidly expanding its network of gathering pipelines and facilities throughout the Fayetteville Shale play area. During 2009, DeSoto Gathering gathered approximately 367.3 Bcf of gas volumes in the Fayetteville Shale play area, including 26.9 Bcf of third-party natural gas. During 2008, DeSoto Gathering gathered approximately 208.3 Bcf of gas volumes in the Fayetteville Shale play area, including 23.8 Bcf of third-party natural gas. In 2007, DeSoto Gathering gathered approximately 78.7 Bcf of gas volumes in the Fayetteville Shale play area, including 7.6 Bcf of third-party natural gas. The increase in volumes gathered in 2009, 2008 and 2007 was primarily due to our growing production volumes from the Fayetteville Shale play. At the end of 2009, DeSoto Gathering had approximately 1,137 miles of pipe from the individual wellheads to the transmission lines and compression equipment had been installed at 48 central point gathering facilities in the field. Angelina Gathering currently engages in gathering activities in East Texas in connection with our Angelina properties. Angelina Gathering provides gathering support for all of our E&P operations outside of Arkansas. At year-end 2009, Angelina Gathering had approximately 21 miles of pipeline in Texas. Our gathering revenues are expected to grow substantially over the next few years largely as a result of increased development of our acreage in the Fayetteville Shale and the increased development activity undertaken by other operators in the play area.

Gas Marketing

Our gas marketing subsidiary, SES, allows us to capture downstream opportunities related to marketing and transportation of natural gas. SES purchases gas production and sells it to end-users and manages the basis and marketing portfolio and acquires transportation rights on pipelines. Our current marketing operations primarily relate to the marketing of our own gas production and some third-party natural gas. During 2009, we marketed 382.5 Bcf of natural gas, compared to 258.0 Bcf in 2008 and 145.7 Bcf in 2007. Of the total volumes marketed, production from our E&P operated wells accounted for 92% in 2009, compared to 96% in 2008 and 89% in 2007.

In 2008 and 2006, SES became a foundation shipper on two pipeline projects serving the Fayetteville Shale play in anticipation of significant growth in the future production volumes from our operations in the play. In 2008, Fayetteville Express Pipeline LLC, or FEP, which is jointly owned by Kinder Morgan Energy Partners, L.P. and Energy Transfer Partners, L.P., agreed to construct a pipeline with an estimated ultimate capacity of up to 2.0 Bcf per day that will provide our operations in the Fayetteville Shale play with access to midwestern and eastern markets. The application for the pipeline was approved by the Federal Energy Regulatory Commission, or the FERC, in December 2009, and it is expected to be in-service by late 2010 or early 2011. SES has a maximum aggregate commitment of 1,200,000 Dekatherms per day for an initial term of ten years from the in-service date. The other project, which began in 2006 and consists of two pipeline laterals called the Fayetteville and Greenville Laterals, has already been constructed by Texas Gas Transmission, LLC, or Texas Gas, a subsidiary of Boardwalk Pipeline Partners, LP. SES has maximum aggregate commitments of 800,000 MMBtu per day on the Fayetteville Lateral and 640,000 MMBtu per day on the Greenville Lateral.

On April 1, 2009, Texas Gas placed in service the Fayetteville and the Greenville laterals and subsequently reduced the capacity on, or shut down, both laterals on several occasions due to various activities, including maintenance and pipeline inspection. As a result, we curtailed a portion of our natural gas production during the third and fourth quarters of 2009 as Texas Gas remediated pipe anomalies pursuant to protocol agreed with the Pipeline and Hazardous Materials Safety Administration, or PHMSA. On October 8, 2009, Texas Gas announced it received authorization from the PHMSA to operate the Fayetteville and Greenville Laterals at standard operating pressures with a capacity of 805,000 MMBtu per day, which is less than the total capacity anticipated under the firm transportation and resulted in a reduction in the capacity to which we are entitled. Texas Gas is continuing to perform the testing protocol required by PHMSA and, once that testing has been completed and the results known, expects to request from PHMSA the authority to operate the

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Fayetteville Lateral at higher than normal operating pressures under a special permit. In January 2010, Texas Gas added compression facilities that increased peak-day delivery capacity to approximately 1.0 Bcf per day on the Greenville Lateral and approximately 1.1 Bcf per day on the Fayetteville Lateral. The designed peakday delivery capacity of the Fayetteville Lateral is approximately 1.3 Bcf per day once the authority to operate it at higher than normal operating pressures is received from PHMSA or Texas Gas completes other system upgrades on that project. The increase in capacity to 1.3 Bcf per day will be needed in order for Texas Gas to meet its contractual commitments that will be in effect in mid-2011.

Prior to the commencement of service on the Fayetteville and Greenville Laterals, the majority of our gas from the Arkoma Basin was moved to markets in the Midwest and was sold primarily based on two indices, NGPL TexOk and Centerpoint East. The Fayetteville and Greenville Laterals allow us to transport our gas to markets in the eastern United States and interconnect with Texas Gas Zone 1, Tennessee Gas Pipeline 100, Trunkline Zone 1A, ANR, Tennessee Gas Pipeline 800, Columbia Gulf Mainline, TETCO M1 30" and Sonat price indices. We rely in part upon the Fayetteville and Greenville Laterals to service our increased production from the Fayetteville Shale play. There can be no assurance that the amount of gas being produced in the Fayetteville Shale will not exceed the available capacity of the various intrastate or interstate transportation pipelines. Our projections, financial condition, results of operation and planned capital expenditures could be adversely impacted by lack of available capacity and continued capacity reductions, shutdowns or other curtailments of the laterals or other pipelines.

Competition

Our gas gathering and marketing activities compete with numerous other companies offering the same services, many of which possess larger financial and other resources than we have. Some of these competitors are other producers and affiliates of companies with extensive pipeline systems that are used for transportation from producers to end-users. Other factors affecting competition are the cost and availability of alternative fuels, the level of consumer demand and the cost of and proximity to pipelines and other transportation facilities. We believe that our ability to compete effectively within the marketing segment in the future depends upon establishing and maintaining strong relationships with producers and end-users.

Regulation

On March 15, 2006, the United States Department of Transportation, or DOT, issued new rules pertaining to certain gathering lines. Compliance with the new rules has not had a material adverse impact on our operations. We refer you to Other Items Environmental Matters and the risk factor We incur substantial costs to comply with government regulations, especially regulations relating to environmental protection, and could incur even greater costs in the future in Item 1A of Part I of this Form 10-K for a discussion of the impact of government regulation on our Midstream Services business.

On November 20, 2008, the FERC issued a Final Rule in Order No. 720, which requires, in relevant part, major non-interstate natural gas pipelines to post, on a daily basis, specific scheduled flow information at each receipt or delivery point with a design capacity of 15,000 MMBtu per day or more. A major non-interstate pipeline is a pipeline that is not classified as a natural gas company under the NGA and delivers on average more than 50 million MMBtu of gas annually over a three year period. Our gathering system in Arkansas constitutes a major non-interstate pipeline under Order No. 720 and will be required to comply with the requirements of Order No. 720 once they become effective for major non-interstate pipelines. On December 11, 2008, the American Gas Association filed a Motion for an Extension of Time to Comply with Order No. 720 arguing that some major non-interstate pipelines will need additional time in which to determine which receipt and delivery points are subject to the posting requirements, obtain corporate approval for expenditures needed for compliance and develop internet posting systems. On January 15, 2009, FERC granted an extension of time for major non-interstate pipelines to comply with the requirements of Order No. 720 until 150 days following the issuance of an order addressing the pending requests for rehearing and such an order was issued on January 21, 2010. We believe that we will be able to comply with the requirements of Order No. 720 within the prescribed 150 days.

Natural Gas Distribution

Effective July 1, 2008, we sold all of the capital stock of Arkansas Western Gas for $223.5 million (net of expenses related to the sale). In order to receive regulatory approval for the sale and certain related transactions, we paid $9.8 million to Arkansas Western Gas for the benefit of its customers. We recorded a pre-tax gain on the sale of $57.3 million in the third quarter of 2008. As a result of the sale of the utility, we are no longer engaged in natural gas distribution operations. Arkansas Western Gas provided operating income for the first half of 2008 of $10.7 million, compared to $10.0 million for the entire year of 2007.

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Other

Our other operations have primarily consisted of real estate development activities concentrated on tracts of land located in Arkansas. There were no sales of commercial real estate in 2009, 2008 or 2007. As of December 31, 2009, we owned our office complex in Fayetteville, Arkansas, an interest in approximately 15 acres of undeveloped real estate near the Fayetteville complex and 731 acres in or near Conway, Arkansas, related to our operations in the Fayetteville Shale play.

Other Items

Reconciliation of Non-GAAP Measures

EBITDA is defined as net income (loss) attributable to Southwestern Energy plus interest, income tax expense, depreciation, depletion and amortization. We have included information concerning EBITDA in this Form 10-K because it is used by certain investors as a measure of the ability of a company to service or incur indebtedness and because it is a financial measure commonly used in our industry. EBITDA should not be considered in isolation or as a substitute for net income (loss) attributable to Southwestern Energy, net cash provided by operating activities or other income or cash flow data prepared in accordance with generally accepted accounting principles in the United

States, or GAAP, or as a measure of our profitability or liquidity. EBITDA as defined above may not be comparable to similarly titled measures of other companies.

We believe that net income (loss) attributable to Southwestern Energy is the financial measure calculated and presented in accordance with GAAP that is most directly comparable to EBITDA as defined. The following table reconciles EBITDA, as defined, with net income (loss) attributable to Southwestern Energy for the years-ended December 31, 2009, 2008 and 2007:

	E&P	**Midstream Services**	**Natural Gas Distribution**	**Other**	
			(in thousands)		
2009					
Net income (loss) attributable to Southwestern Energy........	$ (109,690)	$ 73,950	$	$ 90	$
Depreciation, depletion and amortization................	474,014	19,213		431	
Impairment of natural gas and oil properties ...	907,812				
Net interest expense..	15,237	3,401			
Provision (benefit) for income taxes.........................	(61,724)	45,303		58	
EBITDA..	$ 1,225,649	$ 141,867	$	$ 579	$
2008					
Net income attributable to Southwestern Energy...	$ 492,283	$ 35,145	$ 5,050	$ 35,468	$
Depreciation, depletion and amortization................	399,159	11,402	3,484	415	
Net interest expense..	20,528	6,059	2,317		
Provision for income taxes..	304,636	21,278	3,095	21,990	
EBITDA..	$ 1,216,606	$ 73,884	$ 13,946	$ 57,873	$
2007					
Net income (loss) attributable to Southwestern Energy........	$ 211,876	$ 6,933	$ 2,746	$ (381)	$
Depreciation, depletion and amortization................	282,387	5,527	6,423	163	
Net interest expense..	16,926	2,006	4,941		
Provision for income taxes..	129,315	4,294	1,672	574	
EBITDA..	$ 640,504	$ 18,760	$ 15,782	$ 356	$

Environmental Matters

Our operations are subject to numerous federal, state and local laws and regulations including the Comprehensive Environmental Response, Compensation and Liability Act, or the CERCLA, the Clean Water Act, the Clean Air Act and similar state statutes. These laws and regulations require permits for drilling wells and the maintenance of bonding requirements in order to drill or operate wells and also regulate the spacing and location of wells, the method of drilling

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and casing wells, the surface use and restoration of properties upon which wells are drilled, the plugging and abandoning of wells, the prevention and cleanup of pollutants and other matters. We maintain insurance against costs of clean-up operations, but we are not fully insured against all such risks. Although future environmental obligations are not expected to have a material impact on the results of our operations or financial condition, there can be no assurance that future developments, such as increasingly stringent environmental laws or enforcement thereof, will not cause us to incur material environmental liabilities or costs.

Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal fines and penalties and the imposition of injunctive relief. Changes in environmental laws and regulations occur frequently, and any changes that result in more stringent and costly waste handling, storage, transport, disposal or cleanup requirements could materially adversely affect our operations and financial position, as well as those in the natural gas and oil industry in general. Although we believe that we are in substantial compliance with applicable environmental laws and regulations and that continued compliance with existing requirements will not have a material adverse impact on us, there can be no assurance that this trend will continue in the future.

The Oil Pollution Act, as amended, or the OPA, and regulations thereunder impose a variety of requirements on responsible parties related to the prevention of oil spills and liability for damages resulting from such spills in United States waters. A responsible party includes the owner or operator of an onshore facility, pipeline or vessel, or the lessee or permittee of the area in which an offshore facility is located. OPA assigns liability to each responsible party for oil cleanup costs and a variety of public and private damages. While liability limits apply in some circumstances, a party cannot take advantage of liability limits if the spill was caused by gross negligence or willful misconduct or resulted from violation of a federal safety, construction or operating regulation. If the party fails to report a spill or to cooperate fully in the cleanup, liability limits likewise do not apply. Few defenses exist to the liability imposed by OPA. OPA imposes ongoing requirements on a responsible party, including the preparation of oil spill response plans and proof of financial responsibility to cover environmental cleanup and restoration costs that could be incurred in connection with an oil spill.

CERCLA, also known as the Superfund law, imposes liability, without regard to fault or the legality of the original conduct, on certain classes of persons that are considered to be responsible for the release of a hazardous substance into the environment. These persons include the owner or operator of the disposal site or sites where the release occurred and companies that transported or disposed or arranged for the transport or disposal of the hazardous substances found at the site. Persons who are or were responsible for releases of hazardous substances under CERCLA may be subject to joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment and for damages to natural resources, and it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment.

The Resource Conservation and Recovery Act, as amended, or the RCRA, generally does not regulate wastes generated by the exploration and production of natural gas and oil. The RCRA specifically excludes from the definition of hazardous waste drilling fluids, produced waters and other wastes associated with the exploration, development or production of crude oil, natural gas or geothermal energy. However, legislation has been proposed in Congress from time to time that would reclassify certain natural gas and oil exploration and production wastes as hazardous wastes, which would make the reclassified wastes subject to much more stringent handling, disposal and clean-up requirements. If such legislation were to be enacted, it could have a significant impact on our operating costs, as well as the natural gas and oil industry in general. Moreover, ordinary industrial wastes, such as paint wastes, waste solvents, laboratory wastes and waste oils, may be regulated as hazardous waste.

We own or lease, and have in the past owned or leased, onshore properties that for many years have been used for or associated with the exploration and production of natural gas and oil. Although we have utilized operating and disposal practices that were standard in the industry at the time, hydrocarbons or other wastes may have been disposed of or released on or under the properties owned or leased by us on or under other locations where such wastes have been taken for disposal. In addition, a portion of these properties have been operated by third parties whose treatment and disposal or release of wastes was not under our control. These properties and the wastes disposed thereon may be subject to CERCLA, the Clean Water Act, the RCRA and analogous state laws. Under such laws, we could be required to remove or remediate previously disposed wastes (including waste disposed of or released by prior owners or operators) or property contamination (including groundwater contamination by prior owners or operators), or to perform remedial plugging or closure operations to prevent future contamination.

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The Federal Water Pollution Control Act, as amended, or the FWPCA, imposes restrictions and strict controls regarding the discharge of produced waters and other natural gas and oil waste into navigable waters. Permits must be obtained to discharge pollutants to waters and to conduct construction activities in waters and wetlands. The FWPCA and similar state laws provide for civil, criminal and administrative penalties for any unauthorized discharges of pollutants and unauthorized discharges of reportable quantities of oil and other hazardous substances. Many state discharge regulations and the Federal National Pollutant Discharge Elimination System general permits issued by the Environmental Protection Agency, or the EPA, prohibit the discharge of produced water and sand, drilling fluids, drill cuttings and certain other substances related to the natural gas and oil industry into coastal waters. Although the costs to comply with zero discharge mandates under federal or state law may be significant, the entire industry is expected to experience similar costs and we believe that these costs will not have a material adverse impact on our results of operations or financial position. The EPA has adopted regulations requiring certain natural gas and oil exploration and production facilities to obtain permits for storm water discharges. Costs may be associated with the treatment of wastewater or developing and implementing storm water pollution prevention plans.

We utilize hydraulic fracturing in our E&P operation as a means of maximizing the productivity of our wells. The knowledge and expertise in fracturing techniques we have developed through our operations in the Fayetteville Shale play are being utilized in our other operating areas, including our Marcellus Shale acreage. In our Fayetteville Shale play, the fracturing fluids we use are comprised of over 99% water, with small quantities of additives containing compounds such as hydrochloric acid, mineral oil, citric acid and biocide. Many of these additives can be found in common consumer and household products. The fracturing fluid is combined with sand and injected under high pressure into the target formation. As the mixture is forced into the formation, the pressure causes the rock to fracture and the sand remains behind to prop open the fractures. These fractures create a pathway for the gas to flow out of the formation and into the wellbore. A 2004 study conducted by the EPA found that certain hydraulic fracturing posed no risk to drinking water and Congress exempted hydraulic fracturing from the Safe Drinking Water Act, or SDWA. Recently, there has been a heightened debate over whether the fluids used in hydraulic fracturing may contaminate drinking water supply and proposals have been made to revisit the environmental exemption for hydraulic fracturing under the SDWA or to enact separate federal legislation or legislation at the state and local government levels that would regulate hydraulic fracturing. Both the United States House of Representatives and Senate are considering Fracturing Responsibility and Awareness of Chemicals (FRAC) Act bills and a number of states, including states in which we have operations, are looking to more closely regulate hydraulic fracturing due to concerns about water supply. The recent congressional legislative efforts seek to regulate hydraulic fracturing to Underground Injection Control program requirements, which would significantly increase well capital costs. We are actively exploring and/or testing new alternatives for certain of the compounds we use in our additives but there can be no assurance that these alternatives will be effective at the volumes and rates we require. If the exemption for hydraulic fracturing is removed from the SDWA, or if the FRAC Act or other legislation is enacted at the federal, state or local level, any restrictions on the use of hydraulic fracturing contained in any such legislation could have a significant impact on our financial condition and results of operation.

Employees

At December 31, 2009, we had 1,702 total employees. None of our employees were covered by a collective bargaining agreement at year-end 2009. We believe that our relationships with our employees are good.

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GLOSSARY OF CERTAIN INDUSTRY TERMS

The definitions set forth below shall apply to the indicated terms as used in this Form 10-K. All natural gas reserves and production reported in this Form 10-K are stated at the legal pressure base of the state or area where the reserves exist and at 60 degrees Fahrenheit.

Acquisition of properties Costs incurred to purchase, lease or otherwise acquire a property, including costs of lease bonuses and options to purchase or lease properties, the portion of costs applicable to minerals when land including mineral rights is purchased in fee, brokers fees, recording fees, legal costs, and other costs incurred in acquiring properties. For additional information, see the SEC s definition in Rule 4-10(a) (1) of Regulation S-X, a link for which is available at the SEC s website, http://www.sec.gov/divisions/corpfin/ecfrlinks.shtml.

Analogous reservoir Analogous reservoirs, as used in resources assessments, have similar rock and fluid properties, reservoir conditions (depth, temperature, and pressure) and drive mechanisms, but are typically at a more advanced stage of development than the reservoir of interest and thus may provide concepts to assist in the interpretation of more limited data and estimation of recovery. When used to support proved reserves, an analogous reservoir refers to a reservoir that shares the following characteristics with the reservoir of interest:

(i)

Same geological formation (but not necessarily in pressure communication with the reservoir of interest);

(ii)

Same environment of deposition;

(iii)

Similar geological structure; and

(iv)

Same drive mechanism.

For additional information, see the SEC s definition in Rule 4-10(a) (2) of Regulation S-X, a link for which is available at the SEC s website, http://www.sec.gov/divisions/corpfin/ecfrlinks.shtml.

Available reserves Estimates of the amounts of oil and gas which the registrant can produce from current proved developed reserves using presently installed equipment under existing economic and operating conditions and an estimate of amounts that others can deliver to the registrant under long-term contracts or agreements on a per-day, per-month, or per-year basis. For additional information, see the SEC s definition in Item 1207(d) of Regulation S-K, a link for which is available at the SEC's website, http://www.sec.gov/divisions/corpfin/ecfrlinks.shtml.

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

Bcf One billion cubic feet of gas.

Bcfe One billion cubic feet of gas equivalent. Determined using the ratio of one barrel of crude oil to six Mcf of natural gas.

Btu British thermal unit, which is the heat required to raise the temperature of a one-pound mass of water from 58.5 to 59.5 degrees Fahrenheit.

Dekatherm One million British thermal units (Btu).

Developed oil and gas reserves Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

(i) Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and

(ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

For additional information, see the SEC s definition in Rule 4-10(a) (6) of Regulation S-X, a link for which is available at the SEC s website, http://www.sec.gov/divisions/corpfin/ecfrlinks.shtml.

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Development costs Costs incurred to obtain access to proved reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas. More specifically, development costs, including depreciation and applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to:

(i) Gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, gas lines, and power lines, to the extent necessary in developing the proved reserves.

(ii) Drill and equip development wells, development-type stratigraphic test wells, and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment, and the wellhead assembly.

(iii) Acquire, construct, and install production facilities such as lease flow lines, separators, treaters, heaters, manifolds, measuring devices, and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems.

(iv) Provide improved recovery systems.

For additional information, see the SEC s definition in Rule 4-10(a) (7) of Regulation S-X, a link for which is available at the SEC s website, http://www.sec.gov/divisions/corpfin/ecfrlinks.shtml.

Development project A development project is the means by which petroleum resources are brought to the status of economically producible. As examples, the development of a single reservoir or field, an incremental development in a producing field, or the integrated development of a group of several fields and associated facilities with a common ownership may constitute a development project. For additional information, see the SEC s definition in Rule 4-10(a) (8) of Regulation S-X, a link for which is available at the SEC s website, http://www.sec.gov/divisions/corpfin/ecfrlinks.shtml.

Development well A well drilled within the proved area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive. For additional information, see the SEC s definition in Rule 4-10(a) (9) of Regulation S-X, a link for which is available at the SEC s website, http://www.sec.gov/divisions/corpfin/ecfrlinks.shtml.

Deterministic The method of estimating reserves or resources is called deterministic when a single value for each parameter (from the geoscience, engineering, or economic data) in the reserves calculation is used in the reserves estimation procedure. For additional information, see the SEC s definition in Rule 4-10(a) (5) of Regulation S-X, a link for which is available at the SEC s website, http://www.sec.gov/divisions/corpfin/ecfrlinks.shtml.

Downspacing The process of drilling additional wells within a defined producing area to increase recovery of natural gas and oil from a known reservoir.

EBITDA Represents net income (loss) attributable to Southwestern Energy common stock plus interest, income taxes, depreciation, depletion and amortization and the impairment of natural gas and oil properties. 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 with our net income (loss) attributable to Southwestern Energy from our audited financial statements.

Economically producible The term economically producible, as it relates to a resource, means a resource which generates revenue that exceeds, or is reasonably expected to exceed, the costs of the operation. The value of the products that generate revenue shall be determined at the terminal point of oil and gas producing activities. For additional information, see the SEC s definition in Rule 4-10(a) (10) of Regulation S-X, a link for which is available at the SEC s website, http://www.sec.gov/divisions/corpfin/ecfrlinks.shtml.

Estimated ultimate recovery (EUR) Estimated ultimate recovery is the sum of reserves remaining as of a given date and cumulative production as of that date. For additional information, see the SEC s definition in Rule 4-10(a) (11) of Regulation S-X, a link for which is available at the SEC s website, http://www.sec.gov/divisions/corpfin/ecfrlinks.shtml.

Field An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition. There may be two or more reservoirs in a field that are separated vertically by intervening impervious, strata, or laterally by local geologic barriers, or by both. Reservoirs that are associated by being in overlapping or adjacent fields may be treated as a single or common operational field. The geological terms *structural feature* and *stratigraphic condition* are intended to identify localized geological features as opposed to the broader terms of basins, trends, provinces, plays, areas-of-interest, etc. For additional information, see the SEC s definition in Rule 4-10(a) (15) of Regulation S-X, a link for which is available at the SEC s website, http://www.sec.gov/divisions/corpfin/ecfrlinks.shtml.

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Fracture stimulation A process whereby fluids mixed with proppants are injected into a wellbore under pressure in order to fracture, or crack open, reservoir rock, thereby allowing oil and/or natural gas trapped in the reservoir rock to travel through the fractures and into the well for production.

Gross well or acre A well or acre in which the registrant owns a working interest. The number of gross wells is the total number of wells in which the registrant owns a working interest. For additional information, see the SEC's definition in Item 1208(c)(1) of Regulation S-K, a link for which is available at the SEC's website, http://www.sec.gov/divisions/corpfin/ecfrlinks.shtml.

Gross working interest Gross working interest is the working interest in a given property plus the proportionate share of any royalty interest, including overriding royalty interest, associated with the working interest.

Infill drilling Drilling wells in between established producing wells to increase recovery of natural gas and oil from a known reservoir.

MBbls One thousand barrels of crude oil or other liquid hydrocarbons.

Mcf One thousand cubic feet of natural gas.

Mcfe One thousand cubic feet of natural gas equivalent. Determined using the ratio of one barrel of crude oil to six Mcf of natural gas.

MMBbls One million barrels of crude oil or other liquid hydrocarbons.

MMBtu One million British thermal units (Btu).

MMcf One million cubic feet of natural gas.

MMcfe One million cubic feet of natural gas equivalent. Determined using the ratio of one barrel of crude oil to six Mcf of natural gas.

Net revenue interest Economic interest remaining after deducting all royalty interests, overriding royalty interests and other burdens from the working interest ownership.

Net well or acre Deemed to exist when the sum of fractional ownership working interests in gross wells or acres equals one. The number of net wells or acres is the sum of the fractional working interests owned in gross wells or acres expressed as whole numbers and fractions of whole numbers. For additional information, see the SEC's definition in Item 1208(c)(2) of Regulation S-K, a link for which is available at the SEC's website, http://www.sec.gov/divisions/corpfin/ecfrlinks.shtml.

NYMEX The New York Mercantile Exchange.

Operating interest   An interest in natural gas and oil that is burdened with the cost of development and operation of the property.

Overriding royalty interest   A fractional, undivided interest or right to production or revenues, free of costs, of a lessee with respect to an oil or gas well, that overrides a working interest.

Play   A term applied to a portion of the exploration and production cycle following the identification by geologists and geophysicists of areas with potential oil and gas reserves.

Present Value Index or PVI   A measure that is computed for projects by dividing the dollars invested into the PV-10 resulting from the investment.

Probabilistic   The method of estimation of reserves or resources is called probabilistic when the full range of values that could reasonably occur for each unknown parameter (from the geoscience and engineering data) is used to generate a full range of possible outcomes and their associated probabilities of occurrence. For additional information, see the SEC s definition in Rule 4-10(a) (19) of Regulation S-X, a link for which is available at the SEC s website, http://www.sec.gov/divisions/corpfin/ecfrlinks.shtml.

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Producing property   A natural gas and oil property with existing production.

Productive wells   Producing wells and wells mechanically capable of production. For additional information, see the SEC's definition in Item 1208(c)(3) of Regulation S-K, a link for which is available at the SEC s website, http://www.sec.gov/divisions/corpfin/ecfrlinks.shtml.

Proppant   Sized particles mixed with fracturing fluid to hold fractures open after a hydraulic fracturing treatment. In addition to naturally occurring sand grains, man-made or specially engineered proppants, such as resin-coated sand or high-strength ceramic materials like sintered bauxite, may also be used. Proppant materials are carefully sorted for size and sphericity to provide an efficient conduit for production of fluid from the reservoir to the wellbore.

Proved developed producing   Proved developed reserves that can be expected to be recovered from a reservoir that is currently producing through existing wells.

Proved developed reserves   Proved gas and oil that are also developed gas and oil reserves.

Proved oil and gas reserves   Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time. Also referred to as proved reserves. For additional information, see the SEC s definition in Rule 4-10(a) (22) of Regulation S-X, a link for which is available at the SEC s website, http://www.sec.gov/divisions/corpfin/ecfrlinks.shtml.

Proved reserves   See proved oil and gas reserves.

Proved undeveloped reserves Proved oil and gas reserves that are also undeveloped oil and gas reserves.

PV-10 When used with respect to natural gas and oil reserves, PV-10 means the estimated future gross revenue to be generated from the production of proved reserves, net of estimated production and future development costs, using prices and costs in effect as of the date of the report or estimate, without giving effect to non-property related expenses such as general and administrative expenses, debt service and future income tax expense or to depreciation, depletion and amortization, discounted using an annual discount rate of 10%. Also referred to as present value. After-tax PV-10 is also referred to as standardized measure and is net of future income tax expense.

Reserve life index The quotient resulting from dividing total reserves by annual production and typically expressed in years.

Reserve replacement ratio The sum of the estimated net proved reserves added through discoveries, extensions, infill drilling and acquisitions (which may include or exclude reserve revisions of previous estimates) for a specified period of time divided by production for that same period of time.

Reservoir A porous and permeable underground formation containing a natural accumulation of producible oil and/or gas that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs. For additional information, see the SEC s definition in Rule 4-10(a) (27) of Regulation S-X, a link for which is available at the SEC s website, http://www.sec.gov/divisions/corpfin/ecfrlinks.shtml.

Royalty interest An interest in a natural gas and oil property entitling the owner to a share of oil or gas production free of production costs.

Tcf One trillion cubic feet of gas.

Tcfe One trillion cubic feet of gas equivalent. Determined using the ratio of one barrel of crude oil to six Mcf of natural gas.

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Unconventional play A term used in the natural gas and oil industry to refer to a play in which the targeted reservoirs generally fall into one of three categories: (1) tight sands, (2) coal beds, or (3) gas shales. The reservoirs tend to cover large areas and lack the readily apparent traps, seals and discrete hydrocarbon-water boundaries that typically define conventional reservoirs. These reservoirs generally require fracture stimulation treatments or other special recovery processes in order to produce economic flow rates.

Undeveloped acreage Those leased acres on which wells have not been drilled or completed to a point that would permit the production of economic quantities of oil or gas regardless of whether such acreage contains proved reserves. For additional information, see the SEC's definition in Item 1208(c)(4) of Regulation S-K, a link for which is available at the SEC's website, http://www.sec.gov/divisions/corpfin/ecfrlinks.shtml.

Undeveloped oil and gas reserves Undeveloped oil and gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. Also referred to as undeveloped reserves. For additional information, see the SEC s definition in Rule 4-10(a) (31) of Regulation S-X, a link for which is available at the SEC s website, http://www.sec.gov/divisions/corpfin/ecfrlinks.shtml.

Undeveloped reserves   See   undeveloped oil and gas reserves.

Well spacing   The regulation of the number and location of wells over an oil or gas reservoir, as a conservation measure. Well spacing is normally accomplished by order of the regulatory conservation commission in the applicable jurisdiction. The order may be statewide in its application (subject to change for local conditions) or it may be entered for each field after its discovery. In the operational context,   well spacing   refers to the area attributable between producing wells within the scope of what is permitted under a regulatory order.

Working interest   An operating interest that gives the owner the right to drill, produce and conduct operating activities on the property and to receive a share of production.

Workovers   Operations on a producing well to restore or increase production.

WTI   West Texas Intermediate, the benchmark crude oil in the United States.

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ITEM 1A. RISK FACTORS

In addition to the other information included in this Form 10-K, the following risk factors should be considered in evaluating our business and future prospects. The risk factors described below represent what we believe are the most significant risk factors with respect to us and our business. In assessing the risks relating to our business, investors should also read the other information included in this Form 10-K, including our financial statements and the related notes and   Management   s Discussion and Analysis of Financial Condition and Results of Operation   Cautionary Statement about Forward-Looking Statements.

Natural gas and oil prices are volatile. Volatility in natural gas and oil prices can adversely affect our results and the price of our common stock. This volatility also makes valuation of natural gas and oil producing properties difficult and can disrupt markets.

Natural gas and oil prices have historically been, and are likely to continue to be, volatile. The prices for natural gas and oil are subject to wide fluctuation in response to a number of factors, including:

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relatively minor changes in the supply of and demand for natural gas and oil;

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market uncertainty;

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worldwide economic conditions;

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weather conditions;

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import prices;

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political conditions in major oil producing regions, especially the Middle East;

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actions taken by OPEC;

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competition from other sources of energy; and

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economic, political and regulatory developments.

Historically we have also experienced price volatility as a result of locational differentials for our production from the Arkoma Basin and East Texas which may widen due to pipeline or other constraints. Price volatility makes it difficult to project the return on exploration and development projects involving our natural gas and oil properties and to estimate with precision the value of producing properties that we may own or propose to acquire. In addition, unusually volatile prices often disrupt the market for natural gas and oil properties, as buyers and sellers have more difficulty agreeing on the purchase price of properties. Our results of operations may fluctuate significantly as a result of, among other things, variations in natural gas and oil prices and production performance. In recent years, natural gas and oil price volatility has become increasingly severe.

A substantial or extended decline in natural gas and oil prices would have a material adverse affect on us.

In the first half of 2008, natural gas and oil prices were at or near their highest historical levels but subsequently natural gas and oil prices declined significantly, resulting in a ceiling test write-down in the first quarter of 2009. Natural gas prices remained at substantially lower levels throughout 2009. The further decline in natural gas and oil prices would have a material adverse effect on our financial position, our results of operations, our access to capital and the quantities of natural gas and oil that may be economically produced by us. A significant decrease in price levels for an extended period would negatively affect us in several ways including:

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our cash flow would be reduced, decreasing funds available for capital investments employed to replace reserves or increase production;

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certain reserves would no longer be economic to produce, leading to both lower proved reserves and cash flow; and

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access to other sources of capital, such as equity or long-term debt markets, could be severely limited or unavailable.

Consequently, our revenues and profitability would suffer.

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Lower natural gas and oil prices and/or increased development costs may cause us to record ceiling test write-downs.

We use the full cost method of accounting for our natural gas and oil operations. Accordingly, we capitalize the cost to acquire, explore for and develop natural gas and oil properties. Under the full cost accounting rules of the SEC, the capitalized costs of natural gas and oil properties net of accumulated depreciation, depletion and amortization, and deferred income taxes may not exceed a ceiling limit. This is equal to the present value of estimated future net cash flows from proved natural gas and oil reserves, discounted at 10 percent, plus the lower of cost or fair value of unproved properties included in the costs being amortized, net of related tax effects.

These rules generally require pricing future natural gas and oil production at the unescalated natural gas and oil prices in effect at the end of each fiscal quarter, including the impact of derivatives qualifying as cash flow hedges, utilizing the average price in the 12-month period prior to December 31, 2009, defined as the unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices were defined by contractual arrangements, excluding escalations based upon future conditions. They also require a write-down if the ceiling limit is exceeded, even if prices declined for only a relatively short period of time. Once a write-down is taken, it cannot be reversed in future periods even if natural gas and oil prices increase.

In the period ended March 31, 2009, we incurred a ceiling test write-down of $907.8 million which resulted in an operating loss for our company for 2009. If natural gas and oil prices decline below levels utilized in our ceiling limit test at December 31, 2009 and/or development costs increase, a write-down may occur, which would adversely impact our results of operation and financial condition.

We may have difficulty financing our planned capital investments, which could adversely affect our growth.

We have experienced and expect to continue to experience substantial capital expenditure and working capital needs as a result of our drilling program. Our planned capital investments for 2010 are expected to significantly exceed the net cash generated by our operations. We expect to borrow under our credit facility to fund capital investments that are in excess of our net cash flow and cash on hand. Our ability to borrow under our credit facility is subject to certain conditions. At December 31, 2009, we were in compliance with the borrowing conditions of our credit facility. If we are not in compliance with the terms of our credit facility in the future or if the lenders under our credit facility are unable to fulfill their commitments, we may not be able to borrow under the facility to fund our capital investments. We also cannot be certain that other financing will be available to us on acceptable terms or at all. In the event additional capital resources are unavailable, we may curtail our drilling, development and other activities or be forced to sell some of our assets on an untimely or unfavorable basis. Any such curtailment or sale could have a material adverse effect on our results and future operations.

Working interest owners of some of our properties may be unwilling or unable to cover their portion of development costs, which could change our exploration and development plans.

Some of our working interest owners may have difficulties obtaining the capital needed to finance their activities, or may believe that estimated drilling and completion costs are excessive. As a result, these working interest owners may choose not to participate in certain wells or be unable or unwilling to pay their share of well costs as they become due. These actions could cause us to change our development plans for the affected properties.

Although our estimated natural gas and oil reserve data is independently audited, our estimates may still prove to be inaccurate.

Our reserve data represents the estimates of our reservoir engineers made under the supervision of our management. Our reserve estimates are audited each year by Netherland, Sewell & Associates, Inc., or NSAI, an independent petroleum engineering firm. In conducting its audit, the engineers and geologists of NSAI study our major properties in detail and independently develop reserve estimates. NSAI s audit consists primarily of substantive testing, which includes a detailed review of major properties that account for approximately 88% of the present worth of our total proved reserves. NSAI s audit process consists of sorting all fields by descending present value order and selecting the fields from highest value to descending value until the selected fields account for more than 80% of the present worth of our reserves. The properties in the bottom 20% of the total present worth are the lowest value properties and are not reviewed in the audit. The fields included in approximately the top 88% present value as of December 31, 2009 accounted for approximately 90% of our total proved reserves and approximately 97% of our proved undeveloped reserves. In the conduct of its audit, NSAI did not independently verify the data that we provided to them with respect to ownership interests, oil and gas production, well test data, historical costs of operations and development, product prices, or any

agreements relating to current and future operations of the properties and sales of production. NSAI has advised us that if, in the course of its audit, something came to its attention that brought into question the validity or sufficiency of any such information or data, NSAI did not rely on such information or data until it had satisfactorily resolved any questions relating thereto or had independently verified such information or data. The estimates of NSAI may differ significantly on an individual property basis from our estimates. When, in the aggregate, such differences are within 10%, NSAI is generally satisfied that the estimates of proved reserves are reasonable.

Our estimate of natural gas and oil reserves requires extensive judgments of reservoir engineering data and projections of cost that will be incurred in developing and producing reserves and is generally less precise than other estimates made in connection with financial disclosures. Our reservoir engineers prepare our reserve estimates under the supervision of our management. Reserve estimates are prepared for each of our properties annually by the reservoir engineers assigned to the asset management team to which the property is assigned. The reservoir engineering and financial data included in these estimates are reviewed by senior engineers who are not part of the asset management teams and by our Vice President-Economic Planning and Acquisitions who is the technical person primarily responsible for the preparation of our reserve estimates, and has over twenty years of experience in petroleum engineering, including over fifteen years in estimating oil and gas reserves. On our behalf, the Vice President-Economic Planning and Acquisitions engages NSAI, a worldwide leader of petroleum property analysis for industry and financial organizations and government agencies, to independently audit our proved reserves estimates as discussed in more detail below. The financial data included in the reserve estimates are also separately reviewed by our accounting staff. Our proved reserve estimates, as internally reviewed and audited by NSAI, are submitted for review and approval to our Chief Executive Officer. Finally, upon his approval, NSAI reports the results of its reserve audit to the Board of Directors and final authority over the estimates of our proved reserves rests with our Board of Directors. We incorporate many factors and assumptions into our estimates including:

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expected reservoir characteristics based on geological, geophysical and engineering assessments;

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future production rates based on historical performance and expected future operating and investment activities;

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future oil and gas prices and quality and locational differentials; and

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future development and operating costs.

Although we believe our assumptions are reasonable based on the information available to us at the time we prepare our estimates, our actual results could vary considerably from estimated quantities of proved natural gas and oil reserves (in the aggregate and for a particular geographic location), production, revenues, taxes and development and operating expenditures. In addition, our estimates of reserves may be subject to downward or upward revision based upon production history, results of future exploration and development, prevailing natural gas and oil prices, severance taxes, operating and development costs and other factors. In 2009, our reserves were revised upward by 92.9 Bcfe, primarily due to improved performance in our Fayetteville Shale properties, partially offset by downward revisions due to a comparative decrease in the average 2009 price from the year-end 2008 gas price. In 2008, our reserves were revised upward by 98.1 Bcfe, primarily due to improved performance in our Fayetteville Shale properties, partially offset by downward revisions due to lower year-end oil and gas prices combined with the performance revisions in some of our East Texas and conventional Arkoma Basin properties. In 2007, our reserves were revised upward by 31.0 Bcfe, primarily due to improved performance in our Fayetteville Shale properties, which was partially offset by a downward revision in our Overton properties. These revisions represented no greater than 5% of our total reserve estimates in each of these years, which we believe is indicative of the effectiveness of our internal controls. Because we review our reserve projections for every property at the end of every year, any material change in a reserve estimate is included in subsequent reserve reports.

Finally, recovery of undeveloped reserves generally requires significant capital investments and successful drilling operations. At December 31, 2009, approximately 1,677 Bcfe of our estimated proved reserves were undeveloped. Our reserve data assume that we can and will make these expenditures and conduct these operations successfully, which may not occur. Please read 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 additional information regarding the uncertainty of reserve estimates.

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Our future level of indebtedness and the terms of our financing arrangements may adversely affect operations and limit our growth.

At December 31, 2009, we had total indebtedness of $998.7 million, including borrowings of $324.5 million under our revolving credit facility. At February 25, 2010, we had total long-term indebtedness of $1,089.2 million, including borrowings of $415.0 million under our revolving credit facility. We currently expect to utilize the borrowing availability under our revolving credit facility in order to fund a portion of our capital investments in 2010. See also our risk factor headed We may have difficulty financing our planned capital investments which could adversely affect our growth, above.

The terms of our various financing agreements, including but not limited to the indentures relating to our outstanding senior notes, our revolving credit facility and the master lease agreement relating to our drilling rigs and our other equipment leases, which we collectively refer to as our financing agreements, impose restrictions on our ability and, in some cases, the ability of our subsidiaries to take a number of actions that we may otherwise desire to take, including one or more of the following:

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incurring additional debt, including guarantees of indebtedness;

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redeeming stock or redeeming debt;

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making investments;

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creating liens on our assets; and

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selling assets.

Our level of indebtedness and off-balance sheet obligations, and the covenants contained in our financing agreements, could have important consequences for our operations, including:

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requiring us to dedicate a substantial portion of our cash flow from operations to required payments, thereby reducing the availability of cash flow for working capital, capital investments and other general business activities;

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limiting our ability to obtain additional financing in the future for working capital, capital investments, acquisitions and general corporate and other activities;

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limiting our flexibility in planning for, or reacting to, changes in our business and the industry in which we operate; and

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detracting from our ability to successfully withstand a downturn in our business or the economy generally.

Our ability to comply with the covenants and other restrictions in our financing agreements may be affected by events beyond our control, including prevailing economic and financial conditions. If we fail to comply with the covenants and other restrictions, it could lead to an event of default and the acceleration of our obligations under those agreements. We may not have sufficient funds to make such payments. If we are unable to satisfy our obligations with cash on hand, we could attempt to refinance such debt, sell assets or repay such debt with the proceeds from an equity offering. We cannot assure you that we will be able to generate sufficient cash flow to pay the interest on our debt, to meet our lease obligations, or that future borrowings, equity financings or proceeds from the sale of assets will be available to pay or refinance such debt or obligations. The terms of our financing agreements may also prohibit us from taking such actions. Factors that will affect our ability to raise cash through an offering of our capital stock, a refinancing of our debt or a sale of assets include financial market conditions and our market value and operating performance at the time of such offering or other financing. We cannot assure you that any such proposed offering, refinancing or sale of assets can be successfully completed or, if completed, that the terms will be favorable to us.

If we fail to find or acquire additional reserves, our reserves and production will decline materially from their current levels.

The rate of production from natural gas and oil properties generally declines as reserves are depleted. Unless we acquire additional properties containing proved reserves, conduct successful exploration and development activities, successfully apply new technologies or identify additional behind-pipe zones or secondary recovery reserves, our proved reserves will decline materially as reserves are produced. Future natural gas and oil production is, therefore, highly dependent upon our level of success in acquiring or finding additional reserves.

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Our drilling plans for the Fayetteville Shale play are subject to change.

As of December 31, 2009, we had drilled and completed 1,288 wells relating to our Fayetteville Shale play. 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. Our drilling plans with respect to our Fayetteville Shale play are flexible and are dependent upon a number of factors, including the extent to which we can replicate the results of our most successful Fayetteville Shale wells on our other Fayetteville Shale acreage as well as the natural gas and oil commodity price environment. The determination as to whether we continue to drill wells in the Fayetteville Shale may depend on any one or more of the following factors:

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our ability to determine the most effective and economic fracture stimulation for the Fayetteville Shale formation;

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our ability to transport our production to the most favorable markets;

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material changes in natural gas prices (including regional basis differentials);

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changes in the costs to drill, complete or operate wells and our ability to reduce drilling risks;

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the extent of our success in drilling and completing horizontal wells;

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the costs and availability of oil field personnel services and drilling supplies, raw materials, and equipment and services;

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success or failure of wells drilled in similar formations or which would use the same production facilities;

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receipt of additional seismic or other geologic data or reprocessing of existing data;

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the extent to which we are able to effectively operate our own drillings rigs;

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availability and cost of capital; or

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the impact of federal, state and local government regulation, including any increase in severance taxes.

We continue to gather data about our prospects in the Fayetteville Shale, and 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.

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.

Approximately 178,930 net acres of our Fayetteville Shale acreage will expire in the next three years if we do not drill successful wells to develop the acreage or otherwise take action to extend the leases. As discussed above under Our drilling plans for the Fayetteville Shale play are subject to change, our ability to drill wells depends on a number of factors, including certain factors that are beyond our control. The number of wells we will be required to drill to retain our leasehold rights will be determined by field rules established by the Arkansas Oil and Gas Commission, or the AOGC.

In 2006, the AOGC approved field rules in the Fayetteville Shale, the Moorefield Shale and the Chattanooga Shale as unconventional sources of supply. Under the rules, each drilling unit would consist of a governmental section of approximately 640 acres and operators would be permitted to drill up to 16 wells per drilling unit for each unconventional source of supply. However, current rules are subject to change and could impair our ability to drill or maintain our acreage position. To the extent that any field rules prevent us from successfully drilling wells in certain areas, we may not be able to drill the wells required to maintain our leasehold rights for certain of our Fayetteville Shale acreage.

If our Fayetteville Shale drilling program fails to produce a significant supply of natural gas, our investments in our gas gathering operations could be lost and our commitments for transportation on pipelines could make the sale of our gas uneconomic, which could have an adverse effect on our results of operations, financial condition and cash flows.

As of December 31, 2009, we had invested approximately $548.9 million in our gas gathering system built for the Fayetteville Shale play. We intend to continue to make substantial investments in the expansion of our gas gathering system as we further develop the play. Our gas gathering business will largely rely on gas sourced in our Fayetteville Shale play area in Arkansas. In addition, we have entered into 10-year firm transportation agreements committing us to transportation on the Fayetteville and Greenville laterals recently built by Texas Gas to service the Fayetteville Shale play

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area as well as the pipeline being constructed by Fayetteville Express Pipeline LLC, which is jointly owned by Kinder Morgan Energy Partners, L.P. Our marketing subsidiary has also entered into multiple other firm transportation agreements relating to gas volumes from our Fayetteville Shale play. As of December 31, 2009, our aggregate demand charge commitments under these firm transportation agreements were approximately $1.8 billion. If our Fayetteville Shale drilling program fails to produce a significant supply of natural gas, our investments in our gas gathering operations could be lost, and we could be forced to pay demand charges for transportation on pipelines that we would not be using. These events could have an adverse effect on our results of operations, financial condition and cash flows.

Our exploration, development and drilling efforts and our operation of our wells may not be profitable or achieve our targeted returns.

We require significant amounts of undeveloped leasehold acreage in order to further our development efforts. Exploration, development, drilling and production activities are subject to many risks, including the risk that no commercially productive reservoirs will be discovered. We invest in property, including undeveloped leasehold acreage that we believe will result in projects that will add value over time. However, we cannot assure you that all prospects will result in viable projects or that we will not abandon our initial investments. Additionally, there can be no assurance that leasehold acreage acquired by us will be profitably developed, that new wells drilled by us in prospects that we pursue will be productive or that we will recover all or any portion of our investment in such leasehold acreage or wells. Drilling for natural gas and oil may involve unprofitable efforts, not only from dry wells but also from wells that are productive but do not produce sufficient net reserves to return a profit after deducting drilling, operating and other costs. In addition, wells that are profitable may not achieve our targeted rate of return. Our ability to achieve our target PVI results are dependent upon the current and future market prices for natural gas and crude oil, costs associated with producing natural gas and crude oil and our ability to add reserves at an acceptable cost. We rely to a significant extent on seismic data and other advanced technologies in identifying leasehold acreage prospects and in conducting our exploration activities. The seismic data and other technologies we use do not allow us to know conclusively prior to acquisition of leasehold acreage or drilling a well whether natural gas or oil is present or may be produced economically. The use of seismic data and other technologies also requires greater pre-drilling expenditures than traditional drilling strategies.

In addition, we may not be successful in implementing our business strategy of controlling and reducing our drilling and production costs in order to improve our overall return. The cost of drilling, completing and operating a well is often uncertain, and cost factors can adversely affect the economics of a project. Further, our drilling operations may be curtailed, delayed or canceled as a result of numerous factors, including unexpected drilling conditions, title problems, pressure or irregularities in formations, equipment failures or accidents, adverse weather conditions, environmental and other governmental requirements and the cost of, or shortages or delays in the availability of, drilling rigs, equipment and services.

We incur substantial costs to comply with government regulations, especially regulations relating to environmental protection, and could incur even greater costs in the future.

Our exploration, production, development and gas gathering and marketing operations are regulated extensively at the federal, state and local levels. We have made and will continue to make large expenditures in our efforts to comply with these regulations, including environmental regulation. The natural gas and oil regulatory environment could change in ways that might substantially increase these costs. Hydrocarbon-producing states regulate conservation practices and the protection of correlative rights. These regulations affect our operations and limit the quantity of hydrocarbons we may produce and sell. In addition, at the U.S. federal level, the FERC regulates interstate transportation of natural gas under the NGA. Other regulated matters include marketing, pricing, transportation and valuation of royalty payments.

As an owner or lessee and operator of natural gas and oil properties, and an owner of gas gathering systems, we are subject to various federal, state and local regulations relating to discharge of materials into, and protection of, the environment. These regulations may, among other things, impose liability on us for the cost of pollution clean-up resulting from operations, subject us to liability for pollution damages, and require suspension or cessation of operations in affected areas. Changes in or additions to regulations regarding the protection of the environment could significantly increase our costs of compliance, or otherwise adversely affect our business.

One of the responsibilities of owning and operating natural gas and oil properties is paying for the cost of abandonment. We may incur significant abandonment costs in the future which could adversely affect our financial results.

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Our financial condition and results of operation could be adversely affected if the exemption for hydraulic fracturing is removed from the Safe Drinking Water Act, or if legislation is enacted at the federal, state or local level regulating hydraulic fracturing.

We utilize hydraulic fracturing in our E&P operation as a means of maximizing the productivity of our wells. The knowledge and expertise in fracturing techniques we have developed through our operations in the Fayetteville Shale play are being utilized in our other operating areas, including our Marcellus Shale acreage. In our Fayetteville Shale play, the fracturing fluids we use are comprised of over 99% water, with small quantities of additives containing compounds such as hydrochloric acid, mineral oil, citric acid and biocide. Many of these additives can be found in common consumer and household products. The fracturing fluid is combined with sand and injected under high pressure into the target formation. As the mixture is forced into the formation, the pressure causes the rock to fracture and the sand remains behind to prop open the fractures. These fractures create a pathway for the gas to flow out of the formation and into the wellbore. A 2004 study conducted by the EPA found that certain hydraulic fracturing posed no risk to drinking water and Congress exempted hydraulic fracturing from the Safe Drinking Water Act, or SDWA. Recently, there has been a heightened debate over whether the fluids used in hydraulic fracturing may contaminate drinking water supply and proposals have been made to revisit the environmental exemption for hydraulic fracturing under the SDWA or to enact separate federal legislation or legislation at the state and local government levels that would regulate hydraulic fracturing. Both the United States House of Representatives and Senate are considering Fracturing Responsibility and Awareness of Chemicals (FRAC) Act bills and a number of states, including states in which we have operations, are looking to more closely regulate hydraulic fracturing due to concerns about water supply. The recent congressional legislative efforts seek to regulate hydraulic fracturing to Underground Injection Control program requirements, which would significantly increase well capital costs. We are actively exploring and/or testing new alternatives for certain of the compounds we use in our additives but there can be no assurance that these alternatives will be effective at the volumes and rates we require. If the exemption for hydraulic fracturing is removed from the SDWA, or if the FRAC Act or other legislation is enacted at the federal, state or local level, any restrictions on the use of hydraulic fracturing contained in any such legislation could have a significant impact on our financial condition and results of operation.

Natural gas and oil drilling and producing operations involve various risks.

Our operations are subject to all the risks normally incident to the operation and development of natural gas and oil properties, the drilling of natural gas and oil wells and the sale of natural gas and oil, including but not limited to encountering well blowouts, cratering and explosions, pipe failure, fires, formations with abnormal pressures, uncontrollable flows of oil, natural gas, brine or well fluids, hydrocarbon drainage from adjacent third-party production, release of contaminants into the environment and other environmental hazards and risks and failure of counterparties to perform as agreed.

We maintain insurance against many potential losses or liabilities arising from our operations in accordance with customary industry practices and in amounts that we believe to be prudent. However, our insurance does not protect us against all operational risks. For example, we do not maintain business interruption insurance. Additionally, pollution and environmental risks generally are not fully insurable. These risks could give rise to significant costs not covered by insurance that could have a material adverse effect upon our financial results.

We cannot control activities on properties we do not operate. Failure to fund capital investments may result in reduction or forfeiture of our interests in some of our non-operated projects.

We do not operate some of the properties in which we have an interest and we have limited ability to exercise influence over operations for these properties or their associated costs. As of December 31, 2009, approximately 6% of our gas and oil properties, based on the PV-10 value of our proved developed producing reserves, were operated by other companies. Our dependence on the operator and other working interest owners for these projects and our limited ability to influence operations and associated costs could materially adversely affect the realization of our targeted returns on capital in drilling or acquisition activities and our targeted production growth rate. The success and timing of drilling, development and exploitation activities on properties operated by others depend on a number of factors that are beyond our control, including the operator s expertise and financial resources, approval of other participants for drilling wells and utilization of technology.

When we are not the majority owner or operator of a particular natural gas or oil project, we may have no control over the timing or amount of capital investments associated with such project. If we are not willing or able to fund our capital investments relating to such projects when required by the majority owner or operator, our interests in these projects may be reduced or forfeited.

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

Our ability to bring natural gas and crude oil production to market depends on a number of factors including the availability and proximity of pipelines, gathering systems and processing facilities. In some of the areas where we have operations, we deliver natural gas and crude oil through gathering systems and pipelines that we do not own. With respect to our Fayetteville Shale production, we are relying on third parties to construct additional interstate pipelines to increase our ability to bring our production to market. Delays in the commencement of operations of the new pipelines, the unavailability of the new pipelines or other facilities due to market conditions, mechanical reasons or otherwise could have an adverse impact on our results of operations and financial condition. Any significant change affecting these facilities or our failure to obtain access to existing or future facilities on acceptable terms could restrict our ability to conduct normal operations.

Delays in the construction of the pipelines serving the Fayetteville Shale play or in the receipt of regulatory approvals affecting the pipelines could result in capacity constraints that may limit our ability to sell natural gas and/or receive favorable prices for our gas.

If drilling in the Fayetteville Shale continues to be successful, the amount of gas being produced in the area from new wells, as well as gas produced from existing wells, may exceed the capacity of the various intrastate or interstate transportation pipelines currently available. We have subscribed for capacity on the Fayetteville and Greenville Laterals recently built by Texas Gas Transmission, LLC, and the pipeline being constructed by Fayetteville Express Pipeline LLC which is expected to be in service in late 2010 or early 2011.

On April 1, 2009, Texas Gas placed in service the entire Fayetteville and Greenville laterals and subsequently reduced the capacity on, or shut down, both laterals on several occasions due to various activities, including maintenance and pipeline inspection. As a result, we curtailed a portion of our natural gas production during the third and fourth quarters of 2009 primarily due to the inspections, repairs and maintenance relating to the remediation of pipe anomalies on the Fayetteville and Greenville Laterals. The remediation of the pipe anomalies by Texas Gas was pursuant to an agreement with the Pipeline and Hazardous Materials Safety Administration, or PHMSA, entered during the second quarter 2009, which defined the testing protocol and remediation efforts that Texas Gas would need to complete in order to return to normal operating pressures, and for the Fayetteville Lateral, to operate at higher than normal operating pressures. On October 8, 2009, Texas Gas announced it received authorization from the PHMSA to operate the Fayetteville and Greenville Laterals at standard operating pressures with a capacity of 805,000 MMBtu per day. Texas Gas is continuing to perform the testing protocol required by PHMSA and, once that testing has been completed and the results known, expects to request from PHMSA the authority to operate the Fayetteville Lateral at higher than normal operating pressures under a special permit. In addition, Texas Gas plans to add compression in 2010 that will increase peak-day delivery capacities to approximately 1.0 Bcf per day on the Greenville Lateral, and assuming that the authority is received to operate the Fayetteville Lateral at higher than normal operating pressures, increase peak-day delivery capacities to approximately 1.3 Bcf per day on the Fayetteville Lateral. The compression for the Fayetteville and Greenville Laterals has been approved by the FERC. PHMSA retains discretion as to whether to grant, or to maintain in force, authority to operate a pipeline at higher than normal operating pressures. We cannot predict when or if the Fayetteville Lateral will be able to operate at higher capacities. In addition, PHMSA mandated repairs in conjunction with obtaining the special operating permit or any other substantial delay in obtaining the special operating permit from PHMSA could result in future curtailments of our capacity.

We rely upon the Fayetteville and Greenville Laterals to service our increased production from the Fayetteville Shale play and are relying upon the FEP pipeline s timely construction. There can be no assurance that the amount of gas being produced in the Fayetteville Shale will not exceed the available capacity of the various intrastate or interstate transportation pipelines. Our projections, financial condition, results of operation and planned capital expenditures could be adversely impacted by lack of available capacity and continued capacity reductions, shutdowns or other curtailments of the laterals or other pipelines.

Shortages of oilfield equipment, services, supplies, raw materials and qualified personnel could adversely affect our results of operations.

The demand for qualified and experienced field personnel to drill wells and conduct field operations, geologists, geophysicists, engineers and other professionals in the natural gas and oil industry can fluctuate significantly, often in correlation with natural gas and oil prices, causing periodic shortages. These factors also cause significant increases in costs for equipment, services, personnel and raw materials (such as sand, cement, manufactured proppants and other materials utilized in the provision of the oilfield services). Higher natural gas and oil prices generally stimulate increased

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demand and result in increased prices for drilling rigs, crews and associated supplies, equipment, services and raw materials. In addition, our E&P operations also require local access to large quantities of water supplies and disposal services for produced water in connection with our hydraulic fracture stimulations due to prohibitive transportation costs. We cannot be certain when we will experience shortages or price increases, which could adversely affect our profit margin, cash flow and operating results or restrict our ability to drill wells and conduct ordinary operations.

Our business could be adversely affected by competition with other companies.

The natural gas and oil industry is highly competitive, and our business could be adversely affected by companies that are in a better competitive position. As an independent natural gas and oil company, we frequently compete for reserve acquisitions, exploration leases, licenses, concessions, marketing agreements, equipment and labor against companies with financial and other resources substantially larger than we possess. Many of our competitors may be able to pay more for exploratory prospects and productive natural gas and oil properties and may be able to define, evaluate, bid for and purchase a greater number of properties and prospects than we can. Our ability to explore for natural gas and oil prospects and to acquire additional properties in the future will depend on our ability to conduct operations, to evaluate and select suitable properties and to consummate transactions in this highly competitive environment. In addition, many of our competitors have been operating in some of our core areas for a much longer time than we have or have established strategic long-term positions in geographic regions in which we may seek new entry.

We have made significant investments in our own drilling rig and sand mine operations in order to meet certain of our oilfield service and resource needs, lower our costs and increase of the efficiency of our operations. If disrupted, these operations may adversely impact our results of operations. In addition, these operations may adversely impact our relationships with third-party providers.

We have made significant investments in order to meet certain of our oilfield services needs, including establishing our own drilling rig operations and sand mine and we may make additional investments to expand these operations in the future. Our drilling operations are conducted through our subsidiary, DDI, which had 366 employees as of December 31, 2009. We have lease commitments for 14 drilling rigs and related equipment with respect to DDI's operations and we also own one drilling rig. In addition to these rigs, we have contracts with third-party drilling companies for use of their rigs which may not be terminable without penalty. In 2009, another of our subsidiaries, DeSoto Sand, LLC, began operating our first sand mine in Arkansas in order to meet a portion of our sand needs for the Fayetteville Shale play. We also purchase sand for use in our operations from various third parties, including certain of our oilfield service providers. Our drilling rig and sand mine operations may have an adverse effect on our relationships with our existing third-party service and resource providers or our ability to secure these services and resources from other providers. We may also compete with third-party providers for qualified personnel, which could adversely affect our relationships with such providers. If the operations of our drilling rigs operations and/or sand mine are disrupted or our existing third-party providers discontinue their relationships with us, we may not be able to secure alternative services or resources on a timely basis, or at all. Even if we are able to secure alternative services or resources, there can be no assurance that such services or resources will be of equivalent quality or that pricing and other terms will be favorable to us. If we are unable to secure third-party services or resources or if the terms are not favorable to us, our financial condition and results of operations could be adversely affected.

We depend upon our management team and our operations require us to attract and retain experienced technical personnel.

The successful implementation of our business strategy and handling of other issues integral to the fulfillment of our business strategy depends, in part, on our experienced management team, as well as certain key geoscientists, geologists, engineers and other professionals employed by us. The loss of key members of our management team or other highly qualified technical professionals could have a material adverse effect on our business, financial condition and operating results.

If natural gas prices decline, our failure to hedge a significant portion of our expected 2010 production could adversely affect our results of operations and financial condition.

To reduce our exposure to fluctuations in the prices of natural gas and oil, historically, we have entered into hedging arrangements with respect to a significant portion of our expected production. As of December 31, 2009, we had hedges on approximately 16% of our targeted 2010 natural gas production as compared to approximately 60% to 80% from 2006 to 2008 and 45% for 2009. Our price risk management activities increased gas sales by $587.8 million in 2009, decreased gas sales by $40.5 million in 2008 and increased gas sales by $70.7 million in 2007. If natural gas prices decline in 2010, unless we enter into additional hedging arrangements, our revenues would be adversely affected. To the extent

that we engage in additional hedging activities in the current price environment, we would not realize the benefit of price increases above the levels of the hedges.

In addition, such transactions may expose us to the risk of financial loss in certain circumstances, including instances in which:

.

our production is less than expected;

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there is a widening of price differentials between delivery points for our production and the delivery point assumed in the hedge arrangement;

.

the counterparties to our futures contracts fail to perform the contracts; or

.

a sudden, unexpected event materially impacts natural gas or oil prices.

Finally, future market price volatility could create significant changes to the hedge positions recorded on our financial statements. We refer to you to Quantitative and Qualitative Disclosures about Market Risk in Item 7A of Part II of this Form 10-K.

Our ability to produce gas could be impaired if we are unable to acquire adequate supplies of water for our drilling operations or are unable to dispose of the water we use at a reasonable cost and within applicable environmental rules.

Our inability to locate sufficient amounts of water, or dispose of or recycle water used in our E&P operations, could adversely impact our operations, particularly with respect to our Fayetteville Shale and Marcellus Shale operations. Moreover, the imposition of new environmental initiatives and regulations could include restrictions on our ability to conduct certain operations such as hydraulic fracturing or disposal of waste, including, but not limited to, produced water, drilling fluids and other wastes associated with the exploration, development or production of natural gas. The Federal Water Pollution Control Act, as amended, or the FWPCA, imposes restrictions and strict controls regarding the discharge of produced waters and other natural gas and oil waste into navigable waters. Permits must be obtained to discharge pollutants to waters and to conduct construction activities in waters and wetlands. The FWPCA and similar state laws provide for civil, criminal and administrative penalties for any unauthorized discharges of pollutants and unauthorized discharges of reportable quantities of oil and other hazardous substances. Many state discharge regulations and the Federal National Pollutant Discharge Elimination System general permits issued by the Environmental Protection Agency, or the EPA, prohibit the discharge of produced water and sand, drilling fluids, drill cuttings and certain other substances related to the natural gas and oil industry into coastal waters. The EPA has also adopted regulations requiring certain natural gas and oil exploration and production facilities to obtain permits for storm water discharges. Compliance with environmental regulations and permit requirements governing the withdrawal, storage and use of surface water or groundwater necessary for hydraulic fracturing of wells may increase our operating costs and cause delays, interruptions or termination of our operations, the extent of which cannot be predicted, all of which could have an adverse affect on our operations and financial condition.

Climate change and global warming concerns could lead to additional regulatory measures that may adversely impact our operations and financial condition.

Our E&P operations are currently focused on the production of hydrocarbons from unconventional sources, and we expect to continue to focus on such resources in the future. The production of hydrocarbons from these sources has an energy intensity that is a number of times higher than that for production from conventional sources. Therefore, we expect that the carbon dioxide, or CO_2, intensity of our production will increase in the long-term. We actively seek to reduce the environmental impact of our operations by pursuing more efficient use of natural resources such as hydrocarbons and water and managing and mitigating the emissions to the air, water and soil, with a focus on the reduction of greenhouse gas emissions. With the efforts of our Health, Safety and Environmental Department, we have been able to plan for and comply with environmental initiatives without materially altering our operating strategy. We anticipate making increased expenditures of both a capital and expense nature as a result of the increasingly stringent laws relating to the protection of the environment that will increase the cost of equipment, materials and services whose production utilizes hydrocarbons. We may also face increased competition from alternative energy sources that do not rely on hydrocarbons. We cannot predict with any reasonable degree of certainty our future exposure concerning such matters and if we are unable to find solutions to environmental initiatives as they arise, including reducing the CO_2 emissions for our existing projects, we may have additional costs as well as compliance and operational risks with respect to our existing operations as well as facing difficulties in pursuing new projects.

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Our certificate of incorporation, bylaws, and stockholder rights plan contain provisions that could make it more difficult for someone to either acquire us or affect a change of control.

Certain provisions of our certificate of incorporation and bylaws, together with any stockholder rights plan we might have in place, could discourage an effort to acquire us, gain control of the company, or replace members of our executive management team. These provisions could potentially deprive our stockholders of opportunities to sell shares of our common stock at above-market prices.

ITEM 1B. UNRESOLVED STAFF COMMENTS.

None.

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ITEM 2. PROPERTIES

The summary of our oil and gas reserves as of fiscal year-end 2009 based on average fiscal-year prices, as required by Item 1202 of Regulation S-K, is included in the table headed 2009 Proved Reserves by Category and Summary Operating Data in Business Exploration and Production Our Proved Reserves in Item 1 of this Form 10-K and incorporated by reference into this Item 2. Our proved reserves are based upon estimates prepared for each of our properties annually by the reservoir engineers assigned to the asset management team in the geographic locations in which the property is located. These estimates are reviewed by senior engineers who are not part of the asset management teams and by our Vice President-Economic Planning and Acquisitions, or Vice President-EP&A, who was the technical person primarily responsible for overseeing the preparation of our reserves estimates. Our Vice President-EP&A has more than twenty years of experience in petroleum engineering, including over fifteen years of experience in estimating oil and gas reserves and holds a Bachelor of Science in Chemical Engineering. Prior to joining us in 1993, our Vice President-EP&A worked for Conoco Inc. in various engineering functions. Our Vice President-EP&A is a Registered Professional Engineer in the State of Texas and is a member of the Society of Petroleum Engineers, Society of Petroleum Evaluation Engineers, and an associate member of the American Association of Petroleum Geologists. On our behalf, the Vice President-EP&A engages Netherland, Sewell & Associates, Inc., or NSAI, a worldwide leader of petroleum property analysis for industry and financial organizations and government agencies, to independently audit our proved reserves estimates. NSAI was founded in 1961 and performs consulting petroleum engineering services under Texas Board of Professional Engineers Registration No. F-002699. Within NSAI, the technical persons primarily responsible for auditing our proved reserves estimates each (1) have at a minimum over 25 years of practical experience in petroleum engineering; (2) have at a minimum over 18 years of experience in the estimation and evaluation of reserves; (3) have college degrees; (4) is a registered

Professional Engineer in the State of Texas or a Certified Petroleum Geologist and Geophysicist in the State of Texas; (5) meets or exceeds the education, training, and experience requirements set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers; and (6) is proficient in judiciously applying industry standard practices to engineering and geoscience evaluations as well as applying SEC and other industry reserves definitions and guidelines. The financial data included in the reserve estimates are also separately reviewed by our accounting staff. Our proved reserves estimates, as internally reviewed and audited by NSAI, are submitted for review and approval to our Chief Executive Officer. Finally, upon his approval, NSAI reports the results of its reserve audit to the Board of Directors and final authority over the estimates of our proved reserves rests with our Board of Directors. A copy of NSAI's report has been filed as Exhibit 99.1 to this Form 10-K.

The information regarding our proved undeveloped reserves required by Item 1203 of Regulation S-K is included under the heading Proved Undeveloped Reserves in Business Exploration and Production Our Proved Reserves in Item 1 of this Form 10-K.

The information regarding delivery commitments required by Item 1207 of Regulation S-K is included under the heading Sales, Delivery Commitments and Customers in the Business Exploration and Production Our Operations in Item 1 of this Form 10-K and incorporated by reference into this Item 2. For additional information about our natural gas and oil operations, we refer you to Note 4 to the consolidated financial statements. For information concerning capital investments, we refer you to Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources Capital Investments. We also refer you to Item 6, Selected Financial Data in Part II of this Form 10-K for information concerning natural gas and oil produced.

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The following information is provided to supplement the information that is presented in Item 8 of Part II of this Form 10-K.

Oil and Gas Properties, Wells, Operations and Acreage

Leasehold acreage as of December 31, 2009:

	Undeveloped		Developed	
	Gross	Net	Gross	Net
Fayetteville Shale Play[(1)] ..	689,840	394,538	558,720	368,755
U.S. Exploitation:				
Conventional Arkoma[(2)] .	366,996	278,927	271,476	184,961

East Texas[3]	104,220	61,298	70,679	53,901
Appalachia[4]	150,362	149,317	-	-
New Ventures	41,573	36,125	-	-
	1,352,991	920,205	900,875	607,617

(1) 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.

(2) 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.

(3) 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.

(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 1,475 net acres in 2010, 551 net acres in 2011 and 61,133 net acres in 2012.

Producing wells as of December 31, 2009:

	Gas		Oil		Total		Gross Wells
	Gross	Net	Gross	Net	Gross	Net	Operated
Fayetteville Shale Play ..	1,428	993	-	-	1,428	993	1,160
U.S. Exploitation:							
Conventional Arkoma...	1,193	583	-	-	1,193	583	548
East Texas ...	580	447	2	2	582	449	523
	3,201	2,023	2	2	3,203	2,025	2,231

Drilling and Other Exploratory and Development Activities:

	Exploratory					
	Productive Wells		Dry Wells		Total	
Year	Gross	Net	Gross	Net	Gross	Net

2009	....	1.0	0.9	2.0	1.2	3.0	2.1
2008	....	34.0	22.4	2.0	2.0	36.0	24.4
2007	....	97.0	69.4	5.0	3.7	102.0	73.1

		Development					
		Productive Wells		Dry Wells		Total	
Year		Gross	Net	Gross	Net	Gross	Net
2009	....	418.0	253.6	3.0	1.8	421.0	255.4
2008	....	445.0	270.2	9.0	6.8	454.0	277.0
2007	....	342.0	225.2	12.0	8.5	354.0	233.7

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Present Activities

Wells in progress as of December 31, 2009:

	Gross	Net
Drilling:		
Exploratory	-	-
Development	83.0	51.8
Total	83.0	51.8
Completing:		
Exploratory	1.0	0.1
Development	128.0	76.4
Total	129.0	76.5
Drilling & Completing:		
Exploratory	1.0	0.1
Development	211.0	128.2
Total	212.0	128.3

Production, Average Sales Price and Average Production Cost:

		2009		2008		2007
Gas:						
Production (Bcf)		299.7		192.3		109.9
Average sales price (per Mcf), including hedges	$	5.30	$	7.52	$	6.80
Average sales price (per Mcf), excluding hedges	$	3.34	$	7.73	$	6.16
Oil:						
Production (MBbls)		124		385		614
Average sales price (per Bbl)	$	54.99	$	107.18	$	69.12
Average Production Cost:						
Cost, excluding ad valorem and severance taxes (per Mcfe)	$	0.77	$	0.89	$	0.73

During 2009, we were required to file Form 23, Annual Survey of Domestic Oil and Gas Reserves, with the U.S. Department of Energy. The basis for reporting reserves on Form 23 is not comparable to the reserve data included in Note 4 to the consolidated financial statements in Item 8 to this Form 10-K. The primary differences are that Form 23 reports gross reserves, including the royalty owners share, and includes reserves for only those properties of which we are the operator.

Miles of Pipe

At December 31, 2009, our Midstream Services segment had 1,137 miles and 21 miles of pipe in its gathering systems located in Arkansas and Texas, respectively.

Title to Properties

We believe that we have satisfactory title to substantially all of our active properties in accordance with standards generally accepted in the oil and gas industry. Our properties are subject to customary royalty and overriding royalty interests, certain contracts relating to the exploration, development, operation and marketing of production from such properties, consents to assignment and preferential purchase rights, liens for current taxes, applicable laws and other burdens, encumbrances and irregularities in title, which we believe do not materially interfere with the use of or affect the value of such properties. Prior to acquiring undeveloped properties, we perform a title investigation that is thorough but less vigorous than that conducted prior to drilling, which is consistent with standard practice in the oil and gas industry. Before we commence drilling operations on properties that we operate, we conduct a thorough title examination and perform curative work with respect to significant defects before proceeding with operations. We have performed a thorough title examination with respect to substantially all of our active properties that we operate.

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ITEM 3. LEGAL PROCEEDINGS

We are subject to laws and regulations relating to the protection of the environment. Our policy is to accrue environmental and cleanup related costs of a non-capital nature when it is both probable that a liability has been incurred and when the amount can be reasonably estimated. Management believes any future remediation or other compliance related costs will not have a material effect on our financial position or reported results of operations.

We are subject to litigation and claims that have arisen in the ordinary course of business. Management believes, individually or in aggregate, such litigation and claims will not have a material adverse impact on our financial position or our results of operations but these matters are subject to inherent uncertainties and management s view may change in the future. If an unfavorable final outcome were to occur, there exists the possibility of a material impact on our financial position and the results of operations for the period in which the effect becomes reasonably estimable. We accrue for such items when a liability is both probable and the amount can be reasonably estimated.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

None.

EXECUTIVE OFFICERS OF THE REGISTRANT

Name	Officer Position	Age	Years Served as Officer
Harold M. Korell	Executive Chairman of the Board	65	13
Steven L. Mueller	President and Chief Executive Officer	56	1
Greg D. Kerley	Executive Vice President and Chief Financial Officer	54	20
Mark K. Boling	Executive Vice President, General Counsel and Secretary	52	8
Gene A. Hammons	President, Southwestern Midstream Services Company	64	5

Mr. Korell was appointed Executive Chairman of the Board of Directors in May 2009 and has served as the Chairman of the Board of Directors since May 2002. Mr. Korell also served as our Chief Executive Officer from January 1999 to May 2009 and as President from October 1998 to May 2008. He joined us in 1997 as Executive Vice President and Chief Operating Officer. From 1992 to 1997, he was employed by American Exploration Company where he was most recently Senior Vice President-Operations. From 1990 to 1992, he was Executive Vice President of McCormick Resources and from 1973 to 1989, he held various positions with Tenneco Oil Company, including Vice

President-Production.

Mr. Mueller was appointed Chief Executive Officer in May 2009 and was subsequently elected to the Board of Directors in July 2009. Mr. Mueller joined us as President and Chief Operating Officer in June 2008. He joined us from CDX Gas, LLC, where he was employed as Executive Vice President from September 2007 to May 2008. In December 2008, CDX Gas, LLC voluntarily filed for bankruptcy. In 2009, CDX emerged from bankruptcy and resumed operations as Vitruvian Exploration LLC. From 2001 until 2007, Mr. Mueller served first as the Senior Vice President and General Manager Onshore and later as the Executive Vice President and Chief Operating Officer of The Houston Exploration Company. A graduate of the Colorado School of Mines, Mr. Mueller has over 30 years of experience in the oil and gas industry and has served in multiple operational and managerial roles at Tenneco Oil Company, Fina Oil Company, American Exploration Company, Belco Oil & Gas Company and The Houston Exploration Company.

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Mr. Kerley was appointed to his present position in December 1999. Previously, he served as Senior Vice President and Chief Financial Officer from 1998 to 1999, Senior Vice President-Treasurer and Secretary from 1997 to 1998, Vice President-Treasurer and Secretary from 1992 to 1997, and Controller from 1990 to 1992. Mr. Kerley also served as the Chief Accounting Officer from 1990 to 1998. Prior to joining us, Mr. Kerley held senior financial and accounting positions at Agate Petroleum, Inc. and was a manager for Arthur Andersen, L.L.P. specializing in the energy sector.

Mr. Boling was appointed to his present position in December 2002. He joined us as Senior Vice President, General Counsel and Secretary in January 2002. Prior to joining the company, Mr. Boling had a private law practice in Houston specializing in the natural gas and oil industry from 1993 to 2002. Previously, Mr. Boling was a partner with Fulbright and Jaworski L.L.P. where he was employed from 1982 to 1993.

Mr. Hammons was promoted to President of Southwestern Midstream Services Company in December 2005. He joined the company in July 2005 as Vice President of Southwestern Midstream Services Company. Prior to joining us, he provided consulting services to clients in the natural gas industry. Previously, Mr. Hammons was employed by El Paso Natural Gas Company and Burlington Resources and held managerial positions in facility design and installation, gathering management and marketing over the course of his combined 28-year tenure.

All executive officers are elected at the Annual Meeting of the Board of Directors for one-year terms or until their successors are duly elected. There are no arrangements between any officer and any other person pursuant to which he was selected as an officer. There is no family relationship between any of our executive officers or between any of them and our directors.

PART II

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

Our common stock is traded on the New York Stock Exchange under the symbol SWN. On February 23, 2010, the closing price of our stock was $42.49 and we had 2,815 stockholders of record. The following table presents the high and low sales prices for closing market transactions as reported on the New York Stock Exchange, which prices have been adjusted as appropriate to reflect the two-for-one stock split effected in March 2008.

	Range of Market Prices					
Quarter Ended	**2009**		2008		2007	
March 31..................	**$ 34.14**	**$ 25.99**	$ 34.07	$ 24.82	$ 20.64	$ 16.44
June 30.....................	**$ 45.65**	**$ 30.01**	$ 48.69	$ 33.77	$ 25.09	$ 20.69
September 30...........	**$ 45.08**	**$ 35.39**	$ 48.53	$ 27.91	$ 22.85	$ 18.00
December 31............	**$ 50.62**	**$ 40.28**	$ 37.22	$ 20.81	$ 28.27	$ 21.26

We have indefinitely suspended payment of quarterly cash dividends on our common stock.

Issuer Purchases of Equity Securities

We did not repurchase any shares of our equity securities during 2009. The increase in common stock in treasury in 2009 is due to an increase in shares held on behalf of participants in a non-qualified deferred compensation supplemental retirement savings plan. We refer you to Note 12 Equity to our consolidated financial statements in Item 8 of Part II.

Recent Sales of Unregistered Equity Securities

We did not sell any unregistered equity securities during 2009.

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STOCK PERFORMANCE GRAPH

The following graph compares, for the last five years, the performance of our common stock to the S&P 500 Index and the Dow Jones U.S. Exploration & Production Index. The chart assumes that the value of the investment in our common stock and each index was $100 at December 31, 2004, and that all dividends were reinvested. The stock performance shown on the graph below is not indicative of future price performance.

Southwestern Energy Company

Dow Jones U.S. Exploration & Production

S&P 500 Index

	12/31/04	12/31/05	12/31/06	12/31/07	12/31/08	**12/31/09**
Southwestern Energy Company	100	284	277	440	457	**761**
Dow Jones U.S. Exploration & Production	100	165	174	250	150	**211**
S&P 500 Index	100	105	121	128	81	**102**

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ITEM 6. SELECTED FINANCIAL DATA

The following table sets forth a summary of selected historical financial information for each of the years in the five-year period ended December 31, 2009. This information and the notes thereto are derived from our consolidated financial statements. We refer you to Management s Discussion and Analysis of Financial Condition and Results of Operations and Financial Statements and Supplementary Data.

	2009	2008	2007	2006	2005
	(in thousands except share, per share, stockholder data and percentages)				

Financial Review

Operating revenues:					
Exploration and production	**$ 1,593,231**	$ 1,491,302	$ 795,944	$ 491,545	$ 403,234
Midstream services	**1,603,332**	2,173,971	961,994	475,207	459,890
Gas distribution and other	**687**	118,399	174,914	172,655	179,375
Intersegment revenues	**(1,051,471)**	(1,472,120)	(677,721)	(376,295)	(366,170)
	2,145,779	2,311,552	1,255,131	763,112	676,329
Operating costs and expenses:					
Gas purchases midstream services	**482,836**	710,129	306,336	128,387	124,730
Gas purchases gas distribution		61,439	85,445	79,363	82,689
Operating and general	**259,159**	209,536	166,095	132,691	101,500
Depreciation, depletion and amortization	**493,658**	414,408	293,914	151,290	96,211
Impairment of natural gas and oil properties	**907,812**				
Taxes, other than income taxes	**37,280**	29,272	21,875	25,109	25,279
	2,180,745	1,424,784	873,665	516,840	430,409
Operating income (loss)	**(34,966)**	886,768	381,466	246,272	245,920
Interest expense, net	**18,638**	28,904	23,873	679	15,040
Other income (loss)	**1,449**	4,404	(219)	17,079	4,784
Gain on sale of utility assets		57,264			
Income (loss) before income taxes	**(52,155)**	919,532	357,374	262,672	235,664
Provision (benefit) for income taxes:					
Current	**(64,969)**	122,000			
Deferred	**48,606**	228,999	135,855	99,399	86,431
	(16,363)	350,999	135,855	99,399	86,431
Net income (loss)	**(35,792)**	568,533	221,519	163,273	149,233
Less: net income (loss) attributable to noncontrolling interest	**(142)**	587	345	637	1,473