SOUTHWESTERN ENERGY CO
Form 10-K
February 26, 2009

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, 2008
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 if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant s knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. x

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 $15,977,830,730 based on the New York Stock Exchange Composite Transactions closing price on June 30, 2008, of $47.61. For purposes of this calculation, the registrant has assumed that its directors and executive officers are affiliates.

As of February 23, 2009, the number of outstanding shares of the registrant s Common Stock, par value $0.01, was 343,632,766.

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 19, 2009 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, 2008

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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 the 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 primarily engaged in natural gas and crude oil exploration, development and production (E&P) within the United States. 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 the 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 primarily conduct our exploration and production operations through our wholly-owned subsidiaries, SEECO, Inc. and Southwestern Energy Production Company, or SEPCO. SEECO has historically operated exclusively in Arkansas. It holds a large base of both developed and undeveloped gas reserves in Arkansas and conducts the drilling programs for the Fayetteville Shale play and the conventional drilling program in the Arkansas part of the Arkoma Basin. SEPCO conducts development drilling and exploration programs in the Oklahoma portion of the Arkoma Basin, 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 - Our Midstream Services segment primarily supports our E&P operations and is currently concentrated on the Fayetteville Shale play. Midstream Services generates revenue from gathering fees associated with the transportation of natural gas to market and through the marketing of our own gas production and some third-party natural gas. We engage in gas gathering activities in Arkansas and Texas through our gathering subsidiaries, DeSoto Gathering Company, L.L.C. and Angelina Gathering Company, L.L.C. Our gas marketing subsidiary, Southwestern Energy Services Company, or SES, captures downstream opportunities which arise through marketing and transportation activity.

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 2008, 92% of our operating income and 89% of our EBITDA were generated from our E&P business, compared to 94% of our operating income and 95% of our EBITDA in 2007 and 96% of our operating income and 93% of our EBITDA in 2006. In 2008, 7% of our operating income and 5% of our EBITDA were generated from Midstream Services, compared to 3% of our operating income and 3% of our EBITDA in 2007 and 2% of our operating income and 1% of our EBITDA in 2006. In 2008, 1% of our operating income and 1% of our EBITDA were generated from our Gas Distribution business which was sold effective July 1, 2008, compared to 3% of our operating income and 2% of our EBITDA in 2007 and 2% of our operating income and 3% of our EBITDA in 2006. 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 with our net income.

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 provides us with significant production and reserve growth potential. We intend to continue to develop our acreage position and improve our well results through the use of advanced technologies and detailed technical analysis of our properties.

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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. 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 timing and plans for future enhancement and exploitation efforts, the costs of enhancing, drilling, completing and producing the wells, and the marketing negotiations for our gas production to 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 seek to achieve this by continuing to improve upon and add to our gas gathering infrastructure, which we believe allows us to better manage the physical movement of our production and the costs of our operations. As of December 31, 2008, we have invested approximately $342.3 million in building a gas gathering system in the Fayetteville Shale play which was gathering approximately 802 MMcf per day through 843 miles of gathering lines. We intend to invest $220 million in our Midstream operations in 2009 to continue the expansion of our infrastructure. We have also been pro-active in encouraging the construction of interstate pipelines to provide access to additional markets for our production. Our marketing subsidiary is a foundation shipper on two pipeline projects being developed for the Fayetteville Shale play. These projects will provide access to the eastern United States which will provide new opportunities for us to maximize the realized price for our production.

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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 began as a New Venture project in 2002. As of December 31, 2008, we held 138,638 net undeveloped acres in New Ventures projects, which includes approximately 114,738 net undeveloped acres targeting the Devonian-aged Marcellus Shale in Pennsylvania. In addition to New Ventures prospects, we also seek to enter into and develop oil and gas resources through strategic opportunities to expand existing operations including joint ventures, farm-ins or farm-outs.

Recent Developments

Marcellus Shale Acreage Acquisition. In the first quarter of 2009, we purchased approximately 21,715 net acres in Lycoming County, Pennsylvania, for approximately $8.2 million. Including this acreage acquisition, we currently have approximately 137,000 net undeveloped acres in Pennsylvania as of February 23, 2009, under which we believe the Marcellus Shale is prospective.

2009 Planned Capital Investments and Production Guidance. Our planned capital investment program for 2009 is $1.9 billion, which includes approximately $1.6 billion for our E&P segment, $220 million for our Midstream Services segment, and $40 million for other corporate purposes. Our 2009 capital program is expected to be primarily funded by net cash flow, cash on hand and borrowings under our $1 billion revolving credit facility. The planned capital program for 2009 is flexible and can be modified, including downward, if the low natural gas price environment persists for an extended period of time. 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 2009 gas and oil production of approximately 280 to 284 Bcfe, an increase of approximately 45% over our 2008 production.

Pipeline Precedent Agreement. On October 1, 2008, our marketing subsidiary, SES, signed a precedent agreement pursuant to which it will contract as a foundation shipper for firm transportation services on a proposed new natural gas pipeline of Fayetteville Express Pipeline LLC, which is jointly owned by Kinder Morgan Energy Partners, L.P. and Energy Transfer Partners, L.P. SES will use the new pipeline primarily to deliver gas volumes produced from our operations in the Fayetteville Shale play. Pending regulatory approvals, the pipeline is expected to be in-service by late 2010 or early 2011.

Exploration and Production

Our operations are primarily focused on the Fayetteville Shale, an unconventional reservoir located in the Arkoma Basin in Arkansas. In addition to our significant position in the Fayetteville Shale, we conduct conventional operations in the Arkoma Basin where we target Atokan-age gas reservoirs and in East Texas where we primarily target the James Lime formation. We also hold a significant acreage position in northeastern Pennsylvania, under which we believe the Marcellus Shale is prospective. We will continue to actively seek to develop conventional and unconventional natural gas and oil resource plays with significant exploration and exploitation potential.

Operating income from our E&P segment was $813.5 million in 2008, compared to $358.1 million in 2007 and $237.3 million in 2006. EBITDA from our E&P segment was $1.2 billion in 2008, compared to $640.5 million in 2007 and $386.4 million in 2006. The increases in both our operating income and EBITDA in 2008 and 2007 were due to increased production volumes and higher realized prices, partially offset by increases in operating costs and expenditures. 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 with our net income.

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Our estimated proved natural gas and oil reserves were 2,185 Bcfe at year-end 2008, compared to 1,450 Bcfe at year-end 2007 and 1,026 Bcfe at year-end 2006. The overall increase in total estimated proved reserves in the past three years is primarily due to the discovery and development of the Fayetteville Shale play in Arkansas. The after-tax PV-10, or standardized measure of discounted future net cash flows relating to proved gas and oil reserve quantities, was $2.1 billion at year-end 2008, compared to $2.0 billion at year-end 2007 and $1.0 billion at year-end 2006. The reconciling difference in after-tax PV-10 and pre-tax PV-10 (a non-GAAP measure which is reconciled in the 2008 Summary Operating Data table below) is the discounted value of future income taxes on the estimated cash flows. Our year-end 2008 estimated proved reserves had a present value of estimated future net cash flows before income tax, or pre-tax PV-10, of $3.0 billion, compared to $2.6 billion at year-end 2007 and $1.3 billion at year-end 2006. 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. At year-end 2008, the market prices for natural gas and crude oil that were used to calculate our PV-10 value were $5.71 per Mcf and $41.00 per barrel, respectively, compared to $6.80 per Mcf and $92.50 per barrel at year-end 2007 and $5.64 per Mcf and $57.25 per barrel at year-end 2006. We refer you to Note 8 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 2008 estimated proved reserves were natural gas and 62% were classified as proved developed, compared to 96% and 64%, respectively, in 2007 and 95% and 65%, respectively, in 2006. We operate approximately 95% of our reserves, based on our pre-tax PV-10 value, and our average reserve life approximated 11.2 years at year-end 2008. Sales of natural gas production accounted for 97% of total operating revenues for this segment in 2008, 94% in 2007 and 91% in 2006.

The reserve replacement ratio 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 cost of adding the reserves or indicate the potential value of the reserve additions. Our reserve replacement ratio has averaged over 400% during the last three years, primarily driven by increases in the reserves associated with our Fayetteville Shale play. In 2008, we replaced 523% of our production volumes with an increase of 920.2 Bcfe of proved natural gas and oil reserves as a result of our drilling program and net upward revisions of 98.1 Bcfe. Of the reserve additions, 568.2 Bcfe were proved developed and 352.0 Bcfe were proved undeveloped. The upward reserve revisions during 2008 were primarily due to improved performance of wells in our Fayetteville Shale play, 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 program in the Fayetteville Shale play), including net upward 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.

In 2006, our reserve replacement ratio was 386% (from reserve additions of 365.5 Bcfe primarily driven by our drilling programs in the Fayetteville Shale play, East Texas and conventional Arkoma), including net downward reserve revisions of 86.6 Bcfe. Of the 2006 reserve additions, 153.6 Bcfe were proved developed and 211.9 Bcfe were proved undeveloped. The downward reserve revisions during 2006 were primarily due to a comparative decrease in year-end gas prices, combined with performance revisions in our East Texas and conventional Arkoma Basin properties, which were partially offset by an upward performance revision in our Fayetteville Shale properties.

For the period ending December 31, 2008, our three-year average reserve replacement ratio, including revisions, was 483%. Our reserve replacement ratio for 2008, excluding the effect of reserve revisions, was 473%, compared to 447% in 2007 and 505% in 2006. Excluding reserve revisions, our three-year average reserve replacement ratio is 471%.

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 to continue to be the primary source of our reserve additions in the future; however, our ability to add reserves is dependent upon a number of factors that are beyond our control. We refer you to the risk factors Our drilling plans for the Fayetteville Shale play are subject to

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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.

The development of our proved undeveloped reserves will require us to make significant additional investments. We expect that our proved undeveloped reserves of 840 Bcfe as of December 31, 2008, will require us to invest an additional $1.5 billion in order for those reserves to be brought to production. Our 2008 proved undeveloped reserve additions are expected to be developed and to begin to generate cash inflows over the next five years. 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.

Late in 2008, the SEC adopted major revisions to its required oil and gas reporting disclosures which become effective as of January 1, 2010. Among other things, the amendments provide for the use of the 12-month average price, calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period for purposes of both the disclosure and full-cost accounting rules. The use of new technologies to determine proved reserves is permitted under the new rules, and allows companies to disclose probable and possible reserves to investors unlike current rules which limit disclosure to only proved reserves. The new disclosure requirements also require companies to report the independence and qualifications of the auditor of the reserve estimates and file reports when a third party is relied upon to prepare reserve estimates. The requirements will be effective for annual reports on Form 10-K for fiscal years ending on or after December 31, 2009.

The following table provides information as of December 31, 2008, related to proved reserves, well count, net acreage and PV-10, and 2008 annual information related to production and capital investments for each of our operating areas:

2008 SUMMARY OPERATING DATA

	U.S. Exploitation					
	Fayetteville Shale Play	**Arkoma Basin**	**East Texas**	**Permian/ Gulf Coast** (1)	**New Ventures** (2)	**Total**
Estimated Proved Reserves:						
Total Reserves (Bcfe)	1,545	281	351	-	8	**2,185**
Percent of Total	71%	13%	16%	-	-	**100%**
Percent Natural Gas	100%	100%	97%	-	100%	**100%**
Percent Proved Developed	52%	81%	89%	-	100%	**62%**
Production (Bcfe)	134.5	24.4	31.6	3.1	1.0	**194.6**
Capital Investments (millions)(3)	$ 1,191	$ 133	$ 160	$ 3	$ 73	**$ 1,560**
Total Gross Producing Wells	882	1,163	531	-	14	**2,590**
Total Net Producing Wells	639	584	428	-	10	**1,661**
Total Net Acreage	749,735 (4)	551,471 (5)	134,403 (6)	-	149,909	**1,585,518**
Net Undeveloped Acreage	552,254 (4)	357,792 (5)	98,529 (6)	-	138,638	**1,147,213**
PV-10:						
	$ 2,138	$ 392	$ 485	$ -	$ 9	**$ 3,024**

Pre-tax (millions)[7]												
PV of taxes (millions)[7]		647		118		147		-		3		**915**
After-tax (millions)[7]	$	1,491	$	274	$	338	$	-	$	6	**$**	**2,109**
Percent of Total		71%		13%		16%		-		-		**100%**
Percent Operated[8]		96%		86%		97%		-		84%		**95%**

(1) Our Permian Basin and onshore Texas Gulf Coast properties were sold during 2008.

(2) Includes New Ventures opportunities such as the Marcellus Shale play in Pennsylvania and our Riverton coalbed methane play in Louisiana.

(3) Our Total and Fayetteville Shale play capital investments exclude $36 million related to the purchase of drilling rig related and ancillary equipment.

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(4) Assuming successful wells are not drilled and leases are not extended, leasehold expiring over the next three years will be 94,473 net acres in 2009, 119,398 net acres in 2010 and 16,008 net acres in 2011.

(5) Includes 123,442 net developed acres and 1,930 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 46,427 net acres in 2009, 32,648 net acres in 2010 and 35,963 net acres in 2011.

(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 38,973 net acres in 2009, 21,932 net acres in 2010 and 14,898 net acres in 2011.

(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.

We refer you to Note 8 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.

Fayetteville Shale Play

Our Fayetteville Shale play is now the primary focus of our E&P business. The Fayetteville Shale is an 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 shale is a Mississippian-age shale that is the geologic equivalent of the Caney Shale found on the Oklahoma side of the Arkoma Basin and the Barnett Shale found in north Texas. At December 31, 2008, we held leases for approximately 875,000 net acres in the play area (552,254 net undeveloped acres, 197,481 net developed acres held by Fayetteville Shale production, 123,442 net developed acres held by conventional production and an additional 1,930 net undeveloped acres in the traditional Fairway portion of the Arkoma Basin) down slightly from approximately 906,700 net acres at year-end 2007 due to the sale of 55,631 acres to XTO Energy, Inc. Approximately 1,545 Bcf of our reserves at year-end 2008 were attributable to our Fayetteville Shale play, compared to approximately 716 Bcf at year-end 2007 and 300 Bcf at year-end 2006. Gross production from our operated wells in the Fayetteville Shale play increased from approximately 325 MMcf per day at the beginning of 2008 to approximately 720 MMcf per day by year-end. Approximately 8 MMcf per day of our production at December 31, 2008 was from 22 wells producing from conventional reservoirs located in five counties. Our net production from the Fayetteville Shale play was 134.5 Bcf in 2008, compared to 53.5 Bcf in 2007 and 11.8 Bcf in 2006. In 2009, our estimated production from the Fayetteville Shale play is expected to range between 229 and 232 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 2008, approximately ~~26~~ % 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 undeveloped acreage position as of December 31, 2008 had an average lease term of 5 years, an average royalty interest of 15% and was obtained at an average cost of $140 per acre. 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, 2008, we had spud a total of 1,230 wells in the play, 1,015 of which were operated by us and 215 of which were outside-operated wells. Of the wells spud, 604 were in 2008, 415 were in 2007 and 196 were in 2006. Of the wells spud in 2008, 586 were designated as horizontal wells. At year-end 2008, 804 wells had been drilled and completed, including 726 horizontal wells. Of the 726 horizontal wells, 678 wells were fracture stimulated using either slickwater or crosslinked gel stimulation treatments, or a combination thereof.

During 2008, we continued to improve our drilling practices in the Fayetteville Shale play. Our horizontal wells had 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. This compares to an average completed well cost of $2.9 million per well, 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 during 2007. In 2006, our average completed well cost was $2.8 million per well with an average horizontal lateral length of 2,298 feet and average time to drill to total depth of 18 days from re-entry to re-entry. We also continued to improve our completion practices, as wells placed on production during 2008 averaged initial production rates of 2,777 Mcf per day, compared to average initial production rates of 1,687 Mcf per day and 1,510 Mcf per day in 2007 and 2006, respectively. During 2008, we began to test closer perforation cluster spacing in our horizontal wells with positive results. We tested this technique on approximately 200 of our wells which resulted in a 20% to 25% improvement in early production over average initial production of wells on which we did not utilize this technique. We estimate that ultimate recovery on these wells could be improved by a corresponding 20% to 25% over wells on which we did not utilize this technique and we are currently planning to utilize this technique on all planned wells in 2009. As part of our 2009 drilling program, we will also focus on optimizing the well spacing for the play.

Our total proved net gas reserves booked in the play at year-end 2008 were 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. Of the 1,508 locations, 1,446 were horizontal. The average gross proved reserves for the undeveloped wells included in our year-end reserves was approximately 1.9 Bcf, up from 1.5 Bcf per well at year-end 2007 and 1.15 Bcf per well at year-end 2006. Our gross proved reserves for wells that were placed on production in the second half of 2008 averaged 2.2 Bcf per well. 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. Total proved gas reserves booked in the play in 2006 totaled approximately 300 Bcf from a total of 434 locations, of which 162 were proved developed producing, 9 were proved developed non-producing and 263 were proved undeveloped. If the Fayetteville Shale play continues to be successfully developed, over the next few years, we expect a continued significant level of proved undeveloped reserves in the Fayetteville Shale play.

In 2008, we invested approximately $1.2 billion in our Fayetteville Shale play, which included approximately $1.0 billion to spud 604 wells, and increased our reserves by 984 Bcf, which included upward reserve revisions of 159 Bcf due primarily to improved well performance in our Fayetteville Shale play. Included in this total was $23 million for leasehold acquisition, $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 leasehold acquisition, $97 million for 3-D seismic, and $49 million in capitalized costs and other expenses. In 2006, we invested approximately $388 million, which included $316 million to spud 196 wells, $29 million for leasehold acquisition, $14 million for seismic and $29 million in capitalized costs and other expenses.

In 2009, we plan to invest approximately $1.3 billion in our Fayetteville Shale play, which includes participating in approximately 650 horizontal wells, 500 of which will be operated by us. At December 31, 2008, we had acquired approximately 961 square miles of 3-D seismic data and plan to acquire approximately 139 square miles of 3-D seismic data during 2009, the total of which will give us seismic data on approximately 41% of our net acreage position in the Fayetteville Shale, excluding our acreage in the traditional Fairway portion of the Arkoma Basin.

We believe that our Fayetteville Shale acreage holds significant development potential. Our strategy going forward is to increase our production through development drilling as well as increase the amount of acreage we hold by production while determining 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

Conventional Arkoma Program. 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 and west into the Oklahoma portion of the basin. We refer to our drilling program targeting stratigraphic Atokan-age objectives in Oklahoma and Arkansas as the conventional Arkoma drilling program.

At December 31, 2008, we had approximately 281 Bcf of reserves which were attributable to our conventional Arkoma properties, representing approximately 13% of our total reserves, compared to 304 Bcf at year-end 2007 and 277 Bcf at year-end 2006. In 2008, we invested approximately $133 million and participated in 81 wells in our conventional Arkoma drilling program, of which 67 were successful and 8 were in progress at year-end, resulting in a 92% success rate and adding new reserves of 37 Bcf. This area recorded net downward revisions of approximately 36 Bcf primarily due to a comparative decrease in year-end gas prices and negative performance revisions. Net production from our conventional

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Arkoma properties was 24.4 Bcf in 2008, compared to 23.8 Bcf in 2007 and 20.1 Bcf in 2006. Production over the last few years from the basin has risen as new production stemming from our drilling program has more than offset the natural production decline from existing wells.

Our strategy in the Arkoma Basin is to identify trends using our extensive expertise in the area. In recent years, we have extended our development program into other areas of the basin that had previously been less explored, primarily the Ranger Anticline area and the Midway area, which was our primary focus in 2008.

We began drilling at our Midway prospect area located approximately 11 miles north of Ranger in 2005 and, through year-end 2008, we had drilled a total of 59 wells. Our wells at Midway have primarily targeted the Basham and Borum tight gas sands between 3,500 and 6,000 feet in depth, and net production from the area was 2.7 Bcf in 2008, compared to 0.8 Bcf in 2007 and 0.1 Bcf in 2006. At year-end 2008, we held approximately 31,000 gross acres in our Midway prospect area.

The Ranger Anticline is located at the southern edge of the Arkansas portion of the basin. From 1997 through year-end 2008, we had successfully drilled 215 wells at Ranger. Net production from the field was 9.5 Bcf in 2008, compared to 9.5 Bcf in 2007 and 5.7 Bcf in 2006. At December 31, 2008, we held approximately 96,640 gross acres at Ranger, of which 24,320 acres were developed.

In 2009, we plan to invest approximately $60 million in our conventional Arkoma program and will drill approximately 25 wells.

East Texas. Our East Texas operations are primarily located in the Overton Field in Smith County, Texas, and our Angelina River Trend area located in Angelina, Nacogdoches, San Augustine and Shelby Counties in Texas. At December 31, 2008, we had approximately 351 Bcfe of reserves in East Texas, compared to 353 Bcfe at year-end 2007 and 383 Bcfe at year-end 2006. In 2008, we invested approximately $160 million in East Texas and participated in 50 wells, of which 42 were successful and 8 were in progress at year-end, resulting in a 100% success rate and adding new reserves of 53 Bcfe. This area recorded net downward revisions of approximately 23 Bcfe primarily due to a comparative decrease in year-end gas prices and negative performance revisions. Net production from East Texas was 31.6 Bcfe in 2008, compared to 29.9 Bcfe in 2007 and 32.0 Bcfe in 2006. Production during 2008 grew primarily due to our successful drilling program in the James Lime formation in the Angelina River Trend area which more than offset the natural production decline in our Overton Field.

Our original interest in the Overton Field (which was approximately 10,800 gross acres) was acquired in April 2000 for $6 million. Our wells in the Overton Field produce from four Taylor series sands in the Cotton Valley formation at approximately 12,000 feet. At December 31, 2008, we held approximately 24,400 gross acres in the Overton Field with an average working interest of 85% and an average net revenue interest of 68%. Our proved reserves in the Overton Field were 273 Bcfe at year-end 2008, compared to 315 Bcfe at year-end 2007 and 367 Bcfe at year-end 2006. In 2008, we invested approximately $16 million to drill nine wells at the Overton Field, all of which were successful. Net production from our Overton Field was 19.9 Bcfe in 2008, compared to 25.1 Bcfe in 2007 and 29.8 Bcfe in 2006. We expect our production from the Overton field to continue to decline in 2009 due to the continued lack of significant investment in the further development of the field 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, Pettet and James Lime formations. At December 31, 2008, we held approximately 86,400 gross undeveloped acres and 16,700 gross developed acres at Angelina with an average working interest of 67% and an average net revenue interest of 52%. In 2008, we invested approximately $112 million to drill 41 wells at Angelina, all of which were successful or in progress at December 31, 2008. Our 2008 drilling program was primarily focused on developing the James Lime formation in our Jebel prospect area located in Shelby County, Texas. During 2008, we participated in 32 James Lime horizontal wells (20 of which we operated) and placed 15 wells that we operated on production at an average gross initial production rate of 9.1 MMcfe per day. Our proved reserves in the Angelina area were 74 Bcfe at year-end 2008, compared to 33 Bcfe at year-end 2007 and 16 Bcfe at year-end 2006. Net production from our Angelina properties was 11.3 Bcfe in 2008, compared to 2.5 Bcfe in 2007 and 1.8 Bcfe in 2006.

In 2009, we plan to invest up to $110 million to drill approximately 40 wells in East Texas, 34 of which are planned to be horizontal wells targeting the James Lime formation at Angelina.

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Permian Basin and Gulf Coast. 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 46,200 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. Net production from these areas during 2008 was 3.1 Bcfe, compared to 6.1 Bcfe in 2007 and 8.4 Bcfe in 2006. The sale also included approximately 49,500 acres which were located in Culberson County, Texas, in the Barnett Shale play in the Permian Basin.

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, 2008, we held 138,638 net undeveloped acres in the United States outside of our core operating areas in connection with New Ventures prospects. This compares to 156,465 net undeveloped acres held at year-end 2007 and 89,592 net undeveloped acres held at year-end 2006.

In 2008, we invested approximately $73 million in our New Ventures program, including approximately $58 million in the Marcellus Shale play in Pennsylvania. At year-end 2008, we had approximately 114,738 net acres in Pennsylvania under which we believe the Marcellus Shale is prospective at a total cost of $530 per acre. During 2008, we 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 the first quarter of 2009, we purchased approximately 21,715 net acres in Lycoming County, Pennsylvania, for approximately $8.2 million. Including this acreage acquisition, we currently have approximately 137,000 net undeveloped acres in Pennsylvania where we are targeting the Marcellus Shale.

In 2007, we invested approximately $42 million in our New Ventures program, including $17.5 million to purchase acreage in the Marcellus Shale play. We also invested approximately $10.5 million in 2007 to spud 25 wells in our Riverton coalbed methane project in Caldwell Parish, Louisiana, of which all were successful. We have approximately 35,200 net acres in this project area targeting the Tertiary-age lower Wilcox coals at a depth of approximately 2,800 feet. Additionally in 2007, we invested $5.2 million to participate in 5 outside-operated Woodford Shale wells in Oklahoma. In 2006, we invested approximately $46 million as part of our New Ventures program to purchase acreage and drill 7 exploration wells, of which 5 were successful.

In 2009, we plan to invest approximately $80 million in various unconventional, exploration and New Ventures projects, including the Marcellus Shale play in Pennsylvania.

Acquisitions and Divestitures

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.

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 in cash. 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 of gas and oil properties in 2008 or 2007.

In 2006, we sold our remaining South Louisiana properties to a private company for $12.7 million. These properties had proved reserves of 7.0 Bcfe and produced approximately 1.1 Bcfe annually. In 2006, we acquired additional working interests in our Overton Field for approximately $9 million and also acquired interests in our Riverton coalbed methane project located in Caldwell Parish, Louisiana, for approximately $9 million.

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Capital Investments

During 2008, we invested a total of $1.6 billion in our E&P business and participated in drilling 750 wells, 479 of which were successful, 11 were dry and 260 were in progress at year-end. Of the 260 wells in progress at year-end, 236 were located in our Fayetteville Shale play. Our investments focused primarily on our active drilling programs in the Fayetteville Shale play, East Texas and the conventional Arkoma Basin, which accounted for 76%, 10% and 8% of our E&P capital investments in 2008, respectively. We invested approximately $1.2 billion in our Fayetteville Shale play, $160 million in East Texas, $133 million in our conventional Arkoma Basin program and $73 million in New Ventures projects.

Of the $1.6 billion invested in 2008, approximately $1.3 billion was invested in exploratory and development drilling and workovers, $83 million for leasehold acquisition, $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, $66 million for leasehold acquisitions, $100 million for seismic expenditures, $2 million for producing property acquisitions and $77 million in capitalized interest and expenses and other technology-related expenditures. In 2006, we invested approximately $767 million in our primary E&P business activities and participated in drilling 382 wells. Additionally, we invested $94 million for the purchase of drilling rigs and related equipment which were sold in December 2006 as part of a sale and leaseback transaction. Of the $767 million invested in 2006, approximately $196 million was invested in exploratory drilling, $421 million in development drilling and workovers, $49 million for leasehold acquisition, $21 million for seismic expenditures, $18 million for producing property acquisitions and $62 million in capitalized interest and expenses and other technology-related expenditures. The increases in capital investments and wells drilled over the last three years are primarily due to the acceleration of our drilling program in the Fayetteville Shale play.

In 2009, we plan to invest approximately $1.6 billion in our E&P program and participate in drilling 715 wells. The Fayetteville Shale play will be the primary focus of our capital investments, where we plan to invest approximately $1.3 billion. Our capital investments will also include up to $110 million in East Texas, approximately $60 million in our conventional drilling program in the Arkoma Basin, $80 million in unconventional, exploration and New Ventures projects and $40 million for other E&P projects.

Of the $1.6 billion allocated to our 2009 E&P capital budget, approximately $1.3 billion will be invested in development and exploratory drilling, $56 million in seismic and other geologic and geophysical expenditures, $58 million in leasehold, and $228 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 our planned capital investments in 2009.

Other Revenues

Other revenues and operating income for 2008, 2007 and 2006 included pre-tax gains of approximately $4.8 million, $6.4 million and $4.0 million, respectively, related to the sale of gas-in-storage inventory.

Sales and Major Customers

Our daily natural gas equivalent production averaged 533.1 MMcfe in 2008, compared to 311.1 MMcfe in 2007 and 198.1 MMcfe in 2006. Total natural gas equivalent production was 194.6 Bcfe in 2008, up from 113.6 Bcfe in 2007 and 72.3 Bcfe in 2006. Our natural gas production was 192.3 Bcf in 2008, compared to 109.9 Bcf in 2007 and 68.1 Bcf in 2006. The increase in production in 2008 resulted primarily from an 81.0 Bcf increase in production from the Fayetteville Shale play. Increases in our East Texas and Arkoma net production were offset by decreases resulting from sales of oil and gas properties that occurred during 2008. The increase in production in 2007 resulted primarily from a 41.7 Bcf increase in production from the Fayetteville Shale play and a 3.7 Bcf increase in production from our conventional Arkoma Basin activities, offset by a 2.3 Bcfe decrease in our Gulf Coast and Permian Basin production and a 2.1 Bcfe decrease in our East Texas production. The increase in 2006 production resulted primarily from a 10.0 Bcf increase in production related to our Fayetteville Shale play and a 4.0 Bcfe increase in production from East Texas, partially offset by a decrease in production from our Gulf Coast and Permian Basin properties. We also produced 385,000 barrels of oil in 2008, compared to 614,000 barrels of oil in 2007 and 698,000 barrels of oil in 2006. Our oil production decreased during 2008 due to the sale of our Permian and Gulf Coast properties in the second and third quarters of 2008. For 2008, we are targeting total

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natural gas and crude oil production of approximately 280 to 284 Bcfe, which equates to a growth rate of approximately 45% above our 2008 production volumes.

A portion of our gas production is sold to Arkansas Western Gas Company, or AWG, our former subsidiary which is now owned by SourceGas, LLC. SEECO s sales to AWG were 4.3 Bcf in 2008, compared to 4.8 Bcf in 2007 and 4.7 Bcf in 2006. In connection with the sale of AWG to SourceGas effective on July 1, 2008, SEECO signed a five-year natural gas services agreement with AWG pursuant to which AWG, among other things, will transport SEECO s production on its gathering system to industrial and commercial end-users on AWG s system. SEECO s sales to AWG are dependant upon its ability to successfully bid for AWG gas supply contracts in a competitive bidding process.

SEECO also owns an unregulated natural gas storage facility connected to AWG s distribution system that has historically been utilized to help meet its peak seasonal sales commitments and has in the past provided a competitive advantage in the bidding process. Future sales to AWG will be dependent upon SEECO s success in obtaining gas supply contracts from them. Sales to AWG accounted for approximately 2% of total E&P revenues in 2008, 4% in 2007 and 7% in 2006.

Sales of gas and oil production are conducted under contracts that reflect current short-term 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, 2008, we had hedges in place on 135 Bcf, or approximately 48% of our targeted 2009 gas production, and 50 Bcf of our expected 2010 gas production. We intend to hedge additional future production volumes in the event that natural gas prices rise to levels that protect 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, 2008.

We realized an average wellhead price of $7.52 per Mcf for our natural gas production in 2008, compared to $6.80 per Mcf in 2007 and $6.55 per Mcf in 2006, including the effect of hedges. Our hedging activities decreased our average gas price $0.21 per Mcf in 2008 and increased our average price $0.64 per Mcf in 2007 and $0.18 per Mcf in 2006. Our average oil price realized was $107.18 per barrel in 2008, compared to $69.12 per barrel in 2007 and $58.36 per barrel in 2006, including the effect of hedges. None of our crude oil production was hedged during 2008 or 2007. Our hedging activities lowered our average oil price $4.81 per barrel in 2006.

Disregarding the impact of hedges, the average price received for our gas production has historically been approximately $0.30 to $0.50 per Mcf lower than average NYMEX spot market prices. However, during 2008, 2007 and 2006, widening market differentials caused the difference in our average price received for our gas production to be approximately $0.70 to $1.30 per Mcf lower than spot market prices. The discount was at its widest point in late 2008 due to the impact that the delay in the completion of Boardwalk Pipeline had upon the Centerpoint East differential. Assuming a NYMEX commodity price of $6.00 per Mcf of gas for 2009, the average price received for our gas production is expected to be approximately $0.75 per Mcf below the NYMEX Henry Hub index price, including the impact of our basis hedges.

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 recently 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.

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Sales of crude oil, condensate and gas liquids are not regulated and are made at negotiated prices. Effective January 1, 1995, the FERC implemented regulations establishing an indexing system for transportation rates for oil that allowed for an increase in the cost of transporting oil to the purchaser. The implementation of these regulations has not had a material adverse effect on our results of operations.

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 our own gas production and some third-party natural gas.

Our operating income from this segment was $62.3 million on revenues of $2.2 billion in 2008, compared to $13.2 million on revenues of $962.0 million in 2007 and $4.1 million on revenues of $475.2 million in 2006. The increases in revenues are largely attributable to increased gathering revenues, increased volumes marketed and higher purchased gas costs. EBITDA generated by our midstream services segment was $73.9 million in 2008, compared to $18.8 million in 2007 and $5.3 million in 2006. The increase in 2008 and 2007 operating income and EBITDA was 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 with our net income.

Gas Gathering

We engage in gas gathering activities through our gathering subsidiaries, DeSoto Gathering Company, L.L.C. and Angelina Gathering Company, L.L.C., which we refer to as DGC and AGC, respectively. DGC engages in gathering activities in Arkansas primarily related to the development of our Fayetteville Shale play. In 2008, we invested

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approximately $183.0 million related to these activities and had gathering revenues of $114.9 million, compared to $107.4 million invested and revenues of $37.7 million in 2007 and $48.7 million invested and $7.9 million in revenues in 2006. DGC is rapidly expanding its network of gathering pipelines and facilities throughout the Fayetteville Shale region. During 2008, DGC 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, DGC gathered approximately 78.7 Bcf of gas volumes in the Fayetteville Shale play area, including 7.6 Bcf of third-party natural gas. In 2006, DGC gathered approximately 14.6 Bcf of gas. The increase in volumes gathered in 2008 and 2007 was primarily due to our growing production volumes from the Fayetteville Shale play. At the end of 2008, DGC had approximately 843 miles of pipe from the individual wellheads to the transmission lines and compression equipment had been installed at 37 central point gathering facilities in the field. AGC currently engages in gathering activities in East Texas in connection with our Angelina properties. AGC provides gathering support for all of our E&P operations outside of Arkansas. At year-end 2008, AGC had approximately 9 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 which arise through marketing and transportation activity. SES not only purchases, sells and schedules natural gas to be delivered to certain end-users, but also is involved in basis management, marketing portfolio management and acquiring 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 2008, we marketed 258.0 Bcf of natural gas, compared to 145.7 Bcf in 2007 and 72.7 Bcf in 2006. Purchases from our E&P subsidiaries accounted for 96% of total volumes marketed in 2008, compared to 89% in 2007 and 85% in 2006.

On December 15, 2006, due to the significant growth of future production volumes from our operations in the Fayetteville Shale play, SES signed a precedent agreement with Texas Gas Transmission, LLC (Texas Gas), a subsidiary of Boardwalk Pipeline Partners, LP, for the construction of two pipeline laterals to serve the Fayetteville Shale play. Pursuant to the precedent agreement with Texas Gas, in the third quarter of 2008, SES entered into firm transportation agreements with Texas Gas relating to its commitments for the Fayetteville and Greenville Laterals. SES options to increase the volumes to be transported on each of the laterals were fully exercised in 2008 and 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.

During 2008, 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. On December 24, 2008, the Phase 1 facilities of the Fayetteville Lateral portion of the Texas Gas Pipeline began transporting gas to markets. We expect the Phase 2 facilities, which include the Greenville Lateral that originates at the Texas Gas mainline system near Greenville, Mississippi, and extends eastward to interconnect with various interstate pipelines, to be placed in-service during the second quarter of 2009. When the Phase 2 facilities of the Texas Gas Pipeline are placed in-service, our transportation agreements will give us access to additional markets east of the Mississippi river which could result in increasing our average wellhead price. The Fayetteville and Greenville laterals will transport our gas to markets in the eastern United States and will 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.

On September 30, 2008, again due to anticipated significant growth of future production volumes from our operations in the Fayetteville Shale play, SES entered into a precedent agreement pursuant to which it will contract for firm gas transportation services on a proposed new pipeline of Fayetteville Express Pipeline LLC, which is jointly owned by Kinder Morgan Energy Partners, L.P. and Energy Transfer Partners, L.P. SES will be a Foundation Shipper for the project and will use the new pipeline primarily to deliver gas volumes produced from our operations in the Fayetteville Shale play to eastern markets. Pending regulatory approvals, the pipeline is expected to be in-service by late 2010 or early 2011. The proposed pipeline will have an estimated ultimate capacity of up to 2.0 Bcf per day. Following the approval of the pipeline by the Federal Energy Regulatory Commission, or FERC, and subject to certain conditions, pursuant to the precedent agreement, SES will enter into a firm transportation agreement to transport up to 1,200,000 Dekatherms per day for an initial term of ten years.

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Competition

Our gas 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 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. We also experience competition for our gathering services from other producers and non-affiliated gathering companies and we expect this competition to continue in the future.

Regulation

On March 15, 2006, the Department of Transportation, or the 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 National Gas Act and delivers on average more than 50 million MMBtu of gas annually over a three year period. Our gathering system 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.

Natural Gas Distribution

Effective July 1, 2008, we sold all of the capital stock of Arkansas Western Gas Company (AWG) to SourceGas, L.L.C. 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 AWG 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.

AWG provided operating income for the first half of 2008 of $10.7 million, compared to $10.0 million for the entire year of 2007 and $4.5 million for the entire year of 2006.

Transportation and Other

On May 2, 2006, we sold our 25% interest in NOARK Pipeline System, Limited Partnership (NOARK), a partnership that owns a 723-mile integrated interstate pipeline system known as Ozark Gas Transmission System, to Atlas Pipeline Partners, L.P. for $69.0 million, resulting in a pre-tax gain of $10.9 million. In connection with the sale, we assumed $39.0 million of partnership debt that we had previously guaranteed. Our share of NOARK s results of operations was a pre-tax gain of $0.9 million in 2006 prior to the sale.

Our other operations have primarily consisted of the activities of our wholly-owned subsidiary, A. W. Realty Company, a company with real estate development activities concentrated on tracts of land located in Arkansas. There were no sales of commercial real estate in 2008, 2007 or 2006. As of December 31, 2008, A. W. Realty Company owned our office complex in Fayetteville, Arkansas, an interest in approximately 15 acres of undeveloped real estate near the Fayetteville complex and 457 acres in or near Conway, Arkansas, related to our operations in the Fayetteville Shale play.

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Other Items

Reconciliation of Non-GAAP Measures

EBITDA is defined as net income 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, 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 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 is the financial measure calculated and presented in accordance with generally accepted accounting principles in the United States that is most directly comparable to EBITDA as defined. The following table reconciles EBITDA, as defined, with net income for the years-ended December 31, 2008, 2007 and 2006:

	E&P	Midstream Services	Natural Gas Distribution	Other	T
			(in thousands)		

2008					
Net income..	$ 492,283	$ 35,145	$ 5,050	$ 35,468	**$ 5**
Depreciation, depletion and amortization..............	399,159	11,402	3,484	415	**4**
Net interest expense...	20,528	6,059	2,317		
Provision for income taxes.......................................	304,636	21,278	3,095	21,990	**3**
EBITDA..	$ 1,216,606	$ 73,884	$ 13,946	$ 57,873	**$1,3**
2007					
Net income (loss)...	$ 211,876	$ 6,933	$ 2,746	$ (381)	**$ 2**
Depreciation, depletion and amortization..............	282,387	5,527	6,423	163	**2**
Net interest expense...	16,926	2,006	4,941		
Provision for income taxes.......................................	129,315	4,294	1,672	574	**1**
EBITDA..	$ 640,504	$ 18,760	$ 15,782	$ 356	**$ 6**
2006					
Net income..	$ 151,157	$ 2,976	$ 2,190	$ 6,313	**$ 1**
Depreciation, depletion and amortization..............	143,500	1,773	6,428	94	**1**
Net interest expense...	508		171		
Provision for income taxes.......................................	91,276	554	1,698	5,871	
EBITDA..	$ 386,441	$ 5,303	$ 10,487	$ 12,278	**$ 4**

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 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 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

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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.

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.

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We utilize hydraulic fracturing in connection with certain of our E&P operations. In hydraulic fracturing, large quantities of water, sand, and certain additives are 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 hydraulic fracturing posed no risk to drinking water and Congress exempted hydraulic fracturing from the Safe Drinking Water Act. 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 Safe Drinking Water Act or to enact legislation at the state and local government levels that would regulate the impact of hydraulic fracturing on drinking water supply. If the exemption for hydraulic fracturing is removed from the Safe Drinking Water Act, or if legislation is enacted at the state and local level, it could have a significant impact on the natural gas industry as a whole and on our financial condition and results of operation.

Employees

At December 31, 2008, we had 1,367 total employees. None of our employees were covered by a collective bargaining agreement at year-end 2008. We believe that our relationships with our employees are good.

GLOSSARY OF CERTAIN INDUSTRY TERMS

The definitions set forth below shall apply to the indicated terms as used in this Form 10-K. All volumes of natural gas referred to herein are stated at the legal pressure base of the state or area where the reserves exist and at 60 degrees Fahrenheit and in most instances are rounded to the nearest major multiple.

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).

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

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 attributable to common stock plus interest, income taxes, depreciation, depletion and amortization. We refer to 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 from our audited financial statements.

Exploration prospects or locations A location where a well is drilled to find and produce natural gas or oil reserves not classified as proved, to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir or to extend a known reservoir.

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 acreage or gross wells The total acres or wells, as the case may be, in which a working interest is owned.

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

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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 acres or net wells The sum of the fractional working interests owned in gross acres or gross wells.

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

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.

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

Proved developed reserves Proved reserves that can be expected to be recovered from existing wells with existing equipment and operating methods. For additional information, see the SEC s definition in Rule 4-10(a)(3) 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 The estimated quantities of crude oil, natural gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. For additional information, see the SEC s definition in Rule 4-10(a)(2)(i) through (iii) of Regulation S-X, a link for which is available at the SEC s website, http://www.sec.gov/divisions/corpfin/ecfrlinks.shtml.

Proved undeveloped reserves Proved reserves 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. Reserves on undrilled acreage shall be limited to those drilling units that offset productive units and that are reasonably certain of production when drilled. For additional information, see the SEC s definition in Rule 4-10(a)(4) of Regulation S-X, a link for which is available at the SEC s website, http://www.sec.gov/divisions/corpfin/ecfrlinks.shtml.

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.

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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.

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.

Unconventional play A play in which the targeted reservoirs generally fall into one of three categories: (1) tight sands, (2) coal beds, and (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 stimulation treatments or other special recovery processes in order to produce economic flow rates.

Undeveloped acreage Lease acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of natural gas and oil regardless of whether such acreage contains proved 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. 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.

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:

- relatively minor changes in the supply of and demand for natural gas and oil;
- market uncertainty;
- worldwide economic conditions;
- weather conditions;
- import prices;
- political conditions in major oil producing regions, especially the Middle East;
- 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 budget and 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. A continued or extended 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.

Lower natural gas and oil prices 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 hedges. 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.

If natural gas and oil prices decline below levels at December 31, 2008, a write-down may occur. Write-downs required by these rules do not impact cash flow from operating activities but do reduce net income and stockholders' equity.

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 2009 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, 2008, 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

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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 be unable or unwilling to pay their share of well costs as they become due. These problems 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 NSA, an independent petroleum engineering firm. In conducting its audit, the engineers and geologists of NSA study our major properties in detail and independently develop reserve estimates. NSA s audit consists primarily of substantive testing, which includes a detailed review of major properties that account for approximately 83% of the present worth of our total proved reserves. NSA 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 83% present value as of December 31, 2008 accounted for approximately 83% of our total proved reserves and approximately 92% of our proved undeveloped reserves. In the conduct of its audit, NSA 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. NSA 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, NSA 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 Netherland, Sewell & Associates, Inc. may differ significantly on an individual property basis from our estimates. When, in the aggregate, such differences are within 10%, Netherland, Sewell & Associates, Inc. is generally satisfied that the estimates of proved reserves are reasonable.

Reserve estimates are 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 President and Chief Operating Officer. Finally, the estimates of our proved reserves together with the audit report of Netherland, Sewell & Associates, Inc. are reviewed by our Board of Directors. There are numerous uncertainties and risks that are inherent in estimating quantities of natural gas and oil reserves and projecting future rates of production and timing of development expenditures as many factors are beyond our control. 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 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. In 2006, our reserves were revised downward by 86.6 Bcfe, primarily due to lower prevailing oil and gas prices at year-end combined with performance revisions in some of our East Texas and conventional Arkoma Basin properties, which were partially

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offset by an upward performance revision in our Fayetteville Shale properties. These revisions represented no greater than 8% 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, 2008, approximately 840 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.

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

At December 31, 2008 and at February 23, 2009, we had total indebtedness of $735.4 million, with no amounts borrowed under our revolving credit facility. In January 2008, we issued $600 million of senior notes and used the net proceeds to repay outstanding amounts 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 2009. 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, 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:

- incurring additional debt, including guarantees of indebtedness;
- redeeming stock or redeeming debt;
- making investments;
- creating liens on our assets; and
- 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:

- 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;
- limiting our ability to obtain additional financing in the future for working capital, capital investments, acquisitions and general corporate and other activities;
- limiting our flexibility in planning for, or reacting to, changes in our business and the industry in which we operate; and
- 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, and in the case of the master lease agreement, loss of use of our drilling rigs. 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

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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, through engineering studies, 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.

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

As of December 31, 2008, we had drilled and completed 804 wells relating to our Fayetteville Shale play. At year-end 2008, approximately 26% 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 or complete 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 229,879 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

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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, 2008, we had invested approximately $342.3 million in our gas gathering operations and we intend to invest approximately $220 million in 2009. Our gas gathering business will largely rely on gas sourced in our Fayetteville Shale play area in Arkansas. In addition, we have signed 10-year firm transportation agreements committing us to transportation on the Fayetteville and Greenville laterals being built by Texas Gas Transmission, LLC, a subsidiary of Boardwalk Pipeline Partners, LP, or Texas Gas, to service the Fayetteville Shale play area. We have also entered into a precedent agreement with Fayetteville Express Pipeline LLC, which is jointly owned by Kinder Morgan Energy Partners, L.P. and Energy Transfer Partners, L.P., with respect to another pipeline for the Fayetteville Shale play, pursuant to which we will have significant firm transportation commitments if the pipeline is built. Our marketing subsidiary has also entered into multiple other firm transportation agreements relating to gas volumes from our Fayetteville Shale play. 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 transportation fees on pipeline capacity 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 distribution 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 Federal Energy Regulatory Commission regulates interstate transportation of natural gas under the Natural Gas Act. 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. Effective January 1, 2003, companies were required to reflect abandonment costs as a liability on their balance sheets. We may incur significant abandonment costs in the future which could adversely affect our financial results.

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, 2008, approximately 5% of our gas and oil properties, based on PV-10 value, 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.

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. The Fayetteville and Greenville laterals being built by Texas Gas were supposed to be fully available in January 2009 but are experiencing delays. 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.

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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. For example, during the last half of 2006, we had difficulty obtaining additional well completion services due to a shortage of completion crews in our Fayetteville Shale play area, which resulted in a higher inventory of wells that had been drilled but were awaiting completion. There have also been shortages of drilling rigs and other equipment, as demand for rigs and equipment has increased along with the number of wells being drilled. These factors also cause significant increases in costs for equipment, services and personnel. Higher natural gas and oil prices generally stimulate increased demand and result in increased prices for drilling rigs, crews and associated supplies, equipment and services. 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 drilling rig operations and we have significant commitments with third-party drilling companies.

We have made significant investments in our drilling rig operations, including lease commitments for 14 drilling rigs and related equipment and have hired, as of December 31, 2008, 371 employees for our drilling subsidiary, DeSoto Drilling, Inc. We also own one drilling rig. In addition to the rigs we are leasing, we have contracts for third-party drilling companies for use of their rigs which may not be terminable without penalty. Our drilling rig operations may have an adverse effect on our relationships with our existing third-party rig providers or our ability to secure third-party rigs from other providers. We may also compete with third-party rig providers for qualified personnel, which could adversely affect our relationships with rig providers. If our existing third-party rig providers discontinue their relationships with us, we may not be able to secure alternative rigs on a timely basis, or at all. Even if we are able to secure alternative rigs, there can be no assurance that replacement rigs will be of equivalent quality or that pricing and other terms will be favorable to us. If we are unable to secure third-party rigs or if the terms are not favorable to us, our financial condition and results of operations could be adversely affected.

We have limited experience in operating drilling rigs.

We cannot assure you that we will be able to continue to attract and retain qualified field personnel to operate our drilling rigs or to otherwise effectively conduct our drilling operations. If we are unable to retain qualified personnel or to effectively conduct our drilling operations, our financial and operating results may 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.

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Our hedging activities may prevent us from benefiting from price increases and may expose us to other risks.

To reduce our exposure to fluctuations in the prices of natural gas and oil, we enter into hedging arrangements with respect to a portion of our expected production. As of December 31, 2008, we had hedges on approximately 48% of our targeted 2009 natural gas production. Our price risk management activities decreased revenues by $40.5 million in 2008, and increased revenues by $70.7 million in 2007 and $8.7 million in 2006. To the extent that we engage in hedging activities, we may be prevented from realizing the benefits 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:

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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;

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

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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 you to Quantitative and Qualitative Disclosures about Market Risk in Item 7A of Part II of this Form 10-K.

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.

Our stockholder rights plan, together with certain provisions of our certificate of incorporation and bylaws, 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.

ITEM 2. PROPERTIES

For additional information about our natural gas and oil operations, we refer you to Notes 7 and 8 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.

The following information is provided to supplement the information that is presented in Item 8 of Part II of this Form 10-K. For a further description of our natural gas and oil properties, we refer you to Business Exploration and Production.

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Leasehold acreage as of December 31, 2008:

	Undeveloped		Developed	
	Gross	Net	Gross	Net
Fayetteville Shale Play[(1)].....................	897,200	552,254	283,520	197,481
U. S. Exploitation:				
Conventional Arkoma[(2)]...................	462,898	357,792	299,578	193,679
East Texas[(3)].......................................	131,732	98,529	48,655	35,874
New Ventures[(4)]..................................	143,765	138,638	14,085	11,271
	1,635,595	1,147,213	645,838	438,305

(1) Assuming we do not drill successful wells to develop the acreage and do not extend the leases in our undeveloped acreage in the Fayetteville Shale play, leasehold expiring over the next three years will be 94,473 net acres in 2009, 119,398 net acres in 2010 and 16,008 net acres in 2011.

(2) Includes 123,442 net developed acres and 1,930 net undeveloped acres in our Conventional Arkoma Basin operating area that are also within our Fayetteville Shale focus area but not included in the Fayetteville Shale acreage above. Assuming we do not drill successful wells to develop the acreage and do not extend the leases in our undeveloped acreage in the Conventional Arkoma Basin, leasehold expiring over the next three years will be 46,427 net acres in 2009, 32,648 net acres in 2010 and 35,963 net acres in 2011.

(3) Assuming we do not drill successful wells to develop the acreage and do not extend the leases in our undeveloped acreage in East Texas, leasehold expiring over the next three years will be 38,973 net acres in 2009, 21,932 net acres in 2010 and 14,898 net acres in 2011.

(4) Includes New Ventures project acreage in the Marcellus Shale play in Pennsylvania and our Riverton coalbed methane play in Louisiana.

Producing wells as of December 31, 2008:

	Gas		Oil		Total		Gross Wells
	Gross	Net	Gross	Net	Gross	Net	Operated
Fayetteville Shale Play.............	882	639			882	639	731
U. S. Exploitation							
Conventional Arkoma............	1,163	584			1,163	584	558
East Texas	528	425	3	3	531	428	489
New Ventures............................	14	10			14	10	11
	2,587	1,658	3	3	2,590	1,661	1,789

Wells drilled during the year:

	Exploratory					
	Productive Wells		Dry Holes		Total	
Year	Gross	Net	Gross	Net	Gross	Net
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
2006.........................	48.0	40.0	4.0	2.3	52.0	42.3

	Development					
	Productive Wells		Dry Holes		Total	
Year	Gross	Net	Gross	Net	Gross	Net
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
2006.........................	182.0	138.8	5.0	3.4	187.0	142.2

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Wells in progress as of December 31, 2008:

	Gross	Net
Exploratory......................................	18.0	11.1
Development..................................	242.0	165.4
Total..	260.0	176.5

During 2008, 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 8 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, 2008, our Midstream Services segment had 882 miles and 9 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.

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.

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EXECUTIVE OFFICERS OF THE REGISTRANT

Name	Officer Position	Age	Years Served as Officer
Harold M. Korell	Chief Executive Officer and Chairman of the Board	64	12
Steven L. Mueller	President and Chief Operating Officer	55	
Greg D. Kerley	Executive Vice President and Chief Financial Officer	53	19
Mark K. Boling	Executive Vice President, General Counsel and Secretary	51	7
Gene A. Hammons	President, Southwestern Midstream Services Company	63	4

Mr. Korell was elected as Chairman of the Board in May 2002 and has served as Chief Executive Officer since January 1999. He also served 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 as President and Chief Operating Officer in June 2008 and is responsible for both our E&P business and our Midstream operations. 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 filed for bankruptcy. 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.

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.

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PART II

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

Our common stock is traded on the New York Stock Exchange under the symbol SWN. On February 23, 2009, the closing price of our stock was $25.99 and we had 2,661 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	**2008**		2007		2006	
March 31................	**$ 34.07**	**$ 24.82**	$ 20.64	$ 16.44	$ 21.71	$ 14.67
June 30...................	**$ 48.69**	**$ 33.77**	$ 25.09	$ 20.69	$ 19.99	$ 12.40
September 30.........	**$ 48.53**	**$ 27.91**	$ 22.85	$ 18.00	$ 18.74	$ 13.98
December 31..........	**$ 37.22**	**$ 20.81**	$ 28.27	$ 21.26	$ 21.30	$ 13.93

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 2008. The increase in common stock in treasury in 2008 is due to an increase in shares held on behalf of participants in a non-qualified defined contribution supplemented retirement savings plan. We refer you to Note 6 Pension Plan and Other Postretirement Benefits 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 2008.

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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 MidCap 400 Index, the S&P 500 Index and the Dow Jones U.S. Exploration & Production Index (previously known as the Dow Jones Oil Secondary Index). In June 2008, our common stock was removed from the S&P MidCap 400 Index and instead was added to the S&P 500 Index. Accordingly, that index has been added to the stock performance graph. The chart assumes that the value of the investment in our common stock and each index was $100 at December 31, 2003, 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 MidCap 400 Index

S&P 500 Index

	12/31/03	12/31/04	12/31/05	12/31/06	12/31/07	**12/31/08**
Southwestern Energy Company	100	212	602	587	933	**970**
Dow Jones U.S. Exploration & Production	100	142	235	247	355	**213**
S&P MidCap 400 Index	100	116	131	145	156	**100**
S&P 500 Index	100	111	116	135	142	**90**

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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, 2008. This information and the notes thereto are derived from our consolidated financial statements. We refer to you to Management s Discussion and Analysis of Financial Condition and Results of Operations and Financial Statements and Supplementary Data.

	2008	2007	2006	2005	2004
	(in thousands except share, per share, stockholder data and percentages)				
Financial Review					
Operating revenues					
Exploration and production	**$ 1,491,302**	$ 795,944	$ 491,545	$ 403,234	$ 286,924
Midstream services	**2,173,971**	961,994	475,207	459,890	314,977
Gas distribution and other	**118,399**	174,914	172,655	179,375	158,698
Intersegment revenues	**(1,472,120)**	(677,721)	(376,295)	(366,170)	(283,462)
	2,311,552	1,255,131	763,112	676,329	477,137
Operating costs and expenses					
Gas purchases midstream services	**710,129**	306,336	128,387	124,730	60,804
Gas purchases gas distribution	**61,439**	85,445	79,363	82,689	64,311
Operating and general	**209,536**	166,095	132,691	101,500	78,231
Depreciation, depletion and amortization	**414,408**	293,914	151,290	96,211	73,674
Taxes, other than income taxes	**29,272**	21,875	25,109	25,279	17,830
	1,424,784	873,665	516,840	430,409	294,850
Operating income	**886,768**	381,466	246,272	245,920	182,287
Interest expense, net	**(28,904)**	(23,873)	(679)	(15,040)	(16,992)
Other income (loss)	**4,404**	(219)	17,079	4,784	(362)
Gain on sale of utility assets	**57,264**				
Minority interest in partnership	**(587)**	(345)	(637)	(1,473)	(1,579)
Income before income taxes	**918,945**	357,029	262,035	234,191	163,354
Income taxes					
Current [(1)]	**122,000**				
Deferred	**228,999**	135,855	99,399	86,431	59,778
	350,999	135,855	99,399	86,431	59,778
Net income	**$ 567,946**	$ 221,174	$ 162,636	$ 147,760	$ 103,576
Return on equity	**22.6%**	13.4%	11.3%	13.3%	23.1%

Net cash provided by operating activities	**$1,160,809**	$ 622,735	$ 429,937	$ 304,482	$ 237,897
Net cash used in investing activities	**$ (792,078)**	$ (1,513,497)	$ (630,006)	$ (452,918)	$ (285,448)
Net cash provided by (used in) financing activities	**$ (174,286)**	$ 849,667	$ 19,291	$ 370,906	$ 47,509
Common Stock Statistics (2)					
Earnings per share:					
Basic	**$ 1.66**	$ 0.65	$ 0.49	$ 0.49	$ 0.36
Diluted	**$ 1.64**	$ 0.64	$ 0.47	$ 0.47	$ 0.35
Cash dividends declared and paid per share	**$**	$	$	$	$
Book value per average diluted share	**$ 7.24**	$ 4.74	$ 4.19	$ 3.55	$ 1.51
Market price at year-end	**$ 28.97**	$ 27.86	$ 17.52	$ 17.97	$ 6.34
Number of stockholders of record at year-end	**2,497**	2,275	2,412	2,126	2,022
Average diluted shares outstanding	**346,245,938**	347,442,660	342,575,500	312,618,078	295,702,176

(1) As a result of the gains from the E&P asset sales and the sale of the utility, we used all of our net operating loss carryforward in 2008 and were subject to current alternative minimum taxes of $122.0 million, of which $107.5 million was paid in 2008.

(2) 2007, 2006 and 2005 restated to reflect the two-for-one stock split effected in March 2008. 2004 restated to reflect two-for-one stock splits effected in June 2005, November 2005 and March 2008.

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	2008	2007	2006	2005	2004

Capitalization (in thousands)					
Total debt	**$ 735,400**	$ 978,800	$ 137,800	$ 100,000	$ 325,000
Common stockholders equity	**2,507,830**	1,646,500	1,434,643	1,110,304	447,677
Total capitalization	**$3,243,230**	$ 2,625,300	$ 1,572,443	$ 1,210,304	$ 772,677
Total assets	**$4,760,158**	$ 3,622,716	$ 2,379,069	$ 1,868,524	$ 1,146,144
Capitalization ratios:					
Debt	**22.7%**	37.3%	8.8%	8.3%	42.1%
Equity	**77.3%**	62.7%	91.2%	91.7%	57.9%
Capital Investments (in millions) (1)					
Exploration and production					
Exploration and development	**$ 1,569.1**	$ 1,375.2	$ 767.4	$ 416.2	$ 282.0
Drilling rigs and related equipment (2)	**26.7**	4.5	93.6	35.1	
	1,595.8	1,379.7	861.0	451.3	282.0
Midstream services	**183.0**	107.4	48.7	15.8	
Gas distribution (3)	**3.6**	11.4	11.2	10.9	7.3
Other	**13.8**	4.6	21.5	5.1	5.7
	$ 1,796.2	$ 1,503.1	$ 942.4	$ 483.1	$ 295.0
Exploration and Production					
Natural gas:					
Production, Bcf	**192.3**	109.9	68.1	56.8	50.4
Average price per Mcf, including hedges	**$ 7.52**	$ 6.80	$ 6.55	$ 6.51	$ 5.21
Average price per Mcf, excluding hedges	**$ 7.73**	$ 6.16	$ 6.37	$ 7.73	$ 5.80
Oil:					
Production, MBbls	**385**	614	698	705	618
Average price per barrel, including hedges	**$ 107.18**	$ 69.12	$ 58.36	$ 42.62	$ 31.47
Average price per barrel, excluding hedges	**$ 107.18**	$ 69.12	$ 63.17	$ 54.37	$ 40.55
Total gas and oil production, Bcfe	**194.6**	113.6	72.3	61.0	54.1
Lease operating expenses per Mcfe	**$ 0.89**	$ 0.73	$ 0.66	$ 0.48	$ 0.38
General and administrative expenses per Mcfe	**$ 0.41**	$ 0.48	$ 0.58	$ 0.46	$ 0.36
Taxes, other than income taxes per Mcfe	**$ 0.13**	$ 0.16	$ 0.30	$ 0.37	$ 0.28
Proved reserves at year-end:					
Natural gas, Bcf	**2,175.5**	1,396.9	978.9	772.3	594.5
Oil, MBbls	**1,507**	8,912	7,898	9,079	8,508

Total reserves, Bcfe	**2,184.6**	1,450.3	1,026.3	826.8	645.5
Midstream Services					
Gas volumes marketed, Bcf	**258.0**	145.7	72.7	61.9	57.0
Gas volumes gathered, Bcf	**224.1**	78.7	14.6	2.3	
Natural Gas Distribution (3)					
Sales and transportation volumes, Bcf	**14.5**	23.6	21.8	23.2	24.0
Off-system transportation, Bcf (4)		0.3	0.1		1.0
Total volumes delivered	**14.5**	23.9	21.9	23.2	25.0
Customers at year-end					
Residential	**n/a**	134,616	133,679	130,654	127,622
Commercial	**n/a**	17,180	17,151	16,996	16,815
Industrial	**n/a**	192	173	170	175
	n/a	151,988	151,003	147,820	144,612
Annual degree days	**n/a**	3,699	3,413	3,744	3,678
Percent of normal	**n/a**	91%	83%	91%	90%

(1) Capital investments include an increase of $36.2 million for 2008, a reduction of $20.6 million for 2007 and increases of $88.9 million, $28.1 million and $3.9 million for 2006, 2005 and 2004, respectively, related to the change in accrued expenditures between years.

(2) The 2006 and 2005 drilling rigs and related equipment capital investments were sold in December 2006 as part of a sale and leaseback transaction.

(3) Effective July 1, 2008, we sold our utility subsidiary, Arkansas Western Gas Company and, as a result, we no longer have any natural gas distribution operations. The 2008 column reflects results for the first six months of 2008.

(4) 2008 and 2005 off-system transportation volumes were less than 0.1 Bcf.

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

This Form 10-K contains forward-looking statements that involve risks and uncertainties. Our actual results could differ materially from those anticipated in forward-looking statements for many reasons, including the risks described in the Cautionary Statement About Forward-Looking Statements below, in Item 1A, Risk Factors in Part I and elsewhere in this annual report. You should read the following discussion with the Selected Financial Data and our consolidated financial statements and the related notes included in this Form 10-K.

OVERVIEW

Southwestern Energy Company is an independent energy company primarily focused on the exploration and production of natural gas within the United States. Our operations primarily are located in Arkansas, Oklahoma, Pennsylvania and Texas. We are also focused on creating and capturing additional value at and beyond the wellhead through our established natural gas gathering and marketing businesses, which we refer to collectively as our Midstream Services. We have historically operated principally in three segments: Exploration and Production (E&P), Midstream Services and Natural Gas Distribution. Effective July 1, 2008, we sold our utility subsidiary, Arkansas Western Gas Company (AWG) and, as a result, we no longer have any natural gas distribution operations. The assets and liabilities of AWG were classified as held for sale in our December 31, 2007 balance sheet, however, the results of operations for AWG are appropriately consolidated in the statements of operations and are not presented as discontinued operations. We refer you to Note 2 to the consolidated financial statements for additional information.

We are focused on providing long-term growth in the net asset value of our business, which we achieve in our E&P business through the drillbit. We prepare economic analyses for each of the investment opportunities in our E&P business and rank them based upon the expected present value added for each dollar invested, which we refer to as PVI. The PVI of the future expected cash flows for each project is determined using a 10% discount rate. Our actual PVI results are utilized to help determine the allocation of our future capital investments.

We derive the vast majority of our operating income and cash flow from the natural gas production of our E&P business and expect this to continue in the future. We expect that growth in our operating income and revenues will primarily depend on natural gas prices and our ability to increase our natural gas production. Our ability to increase our natural gas production is dependent upon our ability to economically find and produce natural gas, our ability to control costs and our ability to market natural gas on economically attractive terms to our customers. In recent years, there has been significant price volatility in natural gas and crude oil prices due to a variety of factors we cannot control or predict. These factors, which include weather conditions, political and economic events, and competition from other energy sources, impact supply and demand for natural gas, which in turn determines the sale prices for our production. In addition, the prices we realize for our production are affected by our hedging activities as well as locational differences in market prices. We are subject to credit risk relating to the risk of loss as a result of non-performance by counterparties in our hedging activities. The counterparties are primarily major investment and commercial banks which management believes minimizes credit risks. The credit quality of each counterparty and the level of financial exposure we have to each counterparty are closely monitored to limit our credit risk exposure. We have not incurred any counterparty losses in 2006, 2007 and 2008 related to non-performance and do not anticipate any losses given the information we have currently. However, given the current volatility in the financial markets, we cannot be certain that we will not experience such losses in the future.

In 2008, our gas and oil production increased 71% to 194.6 Bcfe from 113.6 Bcfe in 2007. The 81.0 Bcfe increase in 2008 production was due to an 81.0 Bcf increase in net production from our Fayetteville Shale play. Increases in our East Texas and Arkoma net production were offset by decreases resulting from sales of oil and gas properties that occurred during 2008. In 2007, our production increased 57% to 113.6 Bcfe. The 41.2 Bcfe increase in 2007 production was due to a 41.7 Bcf increase in net production from our Fayetteville Shale play which was slightly offset by a net decrease in our other operating areas. We are targeting 2009 gas and oil production of 280.0 to 284.0 Bcfe, an increase of approximately 45% over our 2008 production. Our year-end reserves grew 51% in 2008 to 2,184.6 Bcfe, up from 1,450.3 Bcfe at the end of 2007. These increases were also primarily fueled by the continued development of our Fayetteville Shale play.

We reported net income of $567.9 million in 2008, or $1.64 per share on a fully diluted basis, up 157% from the prior year. Net income in 2008 included a $35.4 million net of tax gain, or $0.10 per diluted share, related to the sale of our utility subsidiary that closed July 1, 2008. Excluding the $35.4 million gain on the sale of the utility, the increase in net income in 2008 was a result of increased revenues of $1.1 billion, partially offset by an increase in operating costs and expenses of $551.1 million and an increase in interest expense of $5.0 million. Net income in 2007 increased approximately 36% to $221.2 million, or $0.64 per share, compared to 2006. The increase in net income in 2007 was a result of increased revenues of $492.0 million, partially offset by an increase in operating costs and expenses of $356.8 million and an increase in interest expense of $23.2 million. Our cash flow from operating activities increased 86% to $1,160.8 million in 2008 and 45% to $622.7 million in 2007, due to increases in net income and adjustments for non-cash expenses.

Operating income for our E&P segment was $813.5 million in 2008, $358.1 million in 2007 and $237.3 million in 2006. Operating income for our E&P segment increased in 2008 due to an increase in revenues of $695.4 million from an 82.4 Bcf increase in gas production volumes and a $0.72 increase in product prices, partially offset by an increase in operating costs and expenses of $239.9 million. Operating income for our E&P segment increased in 2007 due to an increase in revenues of $304.4 million from higher gas production volumes and increased product prices, partially offset by an increase in operating costs and expenses of $183.6 million. Operating income for our Midstream Services segment was $62.3 million in 2008, compared to $13.2 million in 2007 and $4.1 million in 2006. Operating income for our Midstream Services segment increased in 2008 due to an increase of $77.2 million in gathering revenues and an increase of $6.4 million in the margin generated from our natural gas marketing activities, which were partially offset by a $34.5 million increase in operating costs and expenses, exclusive of purchased gas costs. Operating income for our Midstream Services segment increased in 2007 due to an increase of $29.7 million in gathering revenues and an increase of $0.9 million in the margin generated from our natural gas marketing activities, which were partially offset by a $21.6 million increase in operating costs and expenses, exclusive of purchased gas costs. Operating income for our Natural Gas Distribution segment was $10.7 million for the six months in 2008 prior to the utility sale, compared to $10.0 million in 2007 and $4.5 million in 2006. The increase in operating income for our Natural Gas Distribution segment in 2007 resulted from a rate increase implemented in August, from colder weather and a decrease in operating costs and expenses.

Our capital investments totaled approximately $1.8 billion in 2008, up 19% from $1.5 billion in the prior year. We invested $1.6 billion in our E&P segment in 2008, compared to $1.4 billion in 2007 and $861.0 million in 2006 (including $93.6 million invested in drilling rigs). Funds for our 2008 capital investments were provided by cash flow from operations and net proceeds of $964.0 million from our sales of E&P assets and our utility segment. As a result of our increased cash flow from operations and the proceeds received from asset sales, we were able to lower our total debt-to-capitalization ratio to 23% at December 31, 2008, down from 37% at December 31, 2007.

For 2009, our planned capital investments are $1.9 billion, compared to our 2008 capital investments of approximately $1.8 billion, and include approximately $1.6 billion for our E&P segment, $220 million for our Midstream Services segment and $40 million for other corporate purposes. The $1.6 billion of E&P investments includes approximately $1.3 billion for the development of our Fayetteville Shale play and approximately 80% of our 2009 E&P capital is allocated to drilling. In addition to the planned investments in the Fayetteville Shale play, our E&P investments in 2009 will also focus on our active drilling programs in East Texas and other conventional drilling in the Arkoma Basin. We expect our capital investments in 2009 to be funded from operating cash flow, cash on hand and borrowings under our revolving credit facility. The planned capital program for 2009 is flexible and can be modified, including downward, if the low natural gas price environment persists for an extended period of time. We will reevaluate our proposed investments as needed to take into account prevailing market conditions.

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RESULTS OF OPERATIONS

Exploration and Production

	Year Ended December 31,		
	2008	2007	2006
Revenues (in thousands)	**$ 1,491,302**	$ 795,944	$ 491,545
Operating income (in thousands)	**$ 813,504**	$ 358,079	$ 237,307
Gas production (Bcf)	**192.3**	109.9	68.1
Oil production (MBbls)	**385**	614	698
Total production (Bcfe)	**194.6**	113.6	72.3
Average gas price per Mcf, including hedges	**$ 7.52**	$ 6.80	$ 6.55
Average gas price per Mcf, excluding hedges	**$ 7.73**	$ 6.16	$ 6.37
Average oil price per Bbl, including hedges	**$ 107.18**	$ 69.12	$ 58.36
Average oil price per Bbl, excluding hedges	**$ 107.18**	$ 69.12	$ 63.17

Average unit costs per Mcfe:						
Lease operating expenses	**$**	**0.89**	$	0.73	$	0.66
General and administrative expenses	**$**	**0.41**	$	0.48	$	0.58
Taxes, other than income taxes	**$**	**0.13**	$	0.16	$	0.30
Full cost pool amortization	**$**	**1.99**	$	2.41	$	1.90

Revenues, Operating Income and Production

Revenues. Revenues for our E&P segment were up $695.4 million, or 87%, in 2008, compared to the prior year. Approximately $544.3 million, or 78%, of the increase was attributable to an increase in production volumes and $152.4 million, or 22%, was attributable to higher gas and oil prices realized. E&P revenues were up $304.4 million, or 62%, in 2007, compared to 2006, of which approximately $268.7 million, or 88%, of the increase, was attributable to an increase in production volumes and $33.6 million, or 11%, was attributable to higher gas and oil prices realized. We expect our production volumes to continue to increase due to the development of our Fayetteville Shale play in Arkansas. We are unable to predict gas and oil prices which are subject to wide price fluctuations. As of February 23, 2009, we had hedged 135.0 Bcf of 2009 gas production and 50.0 Bcf of 2010 gas production to limit our exposure to price fluctuations. We refer you to Note 10 to the consolidated financial statements included in this Form 10-K and to Commodity Prices below for additional information. Revenues for 2008, 2007 and 2006 also include pre-tax gains of $4.8 million, $6.4 million and $4.0 million, respectively, related to the sale of gas-in-storage inventory.

Operating Income. Operating income from our E&P segment was $813.5 million in 2008, an increase of 127% from 2007, as the 87% increase in revenues was partially offset by a 55% increase in operating costs and expenses. In 2007, operating income increased 51% to $358.1 million from $237.3 million in 2006, as the 62% increase in revenues was partially offset by a 72% increase in operating costs and expenses.

Production. Gas and oil production was up approximately 71% to 194.6 Bcfe in 2008, as compared to the prior year, due to an 81.0 Bcf increase in net production from our Fayetteville Shale play, as a result of our ongoing development program and increases in our East Texas and Arkoma net production which were offset by decreases in net production resulting from the sale of all of our producing properties in the Permian and Gulf Coast. Gas and oil production in 2007 was up approximately 57% to 113.6 Bcfe, due to a 41.7 Bcf increase in net production from our Fayetteville Shale play and a 0.4 Bcfe decrease in our other operating areas. Our net production from the Fayetteville Shale play was 134.5 Bcf in 2008, up from 53.5 Bcf in 2007 and 11.8 Bcf in 2006. In the second quarter of 2008, we completed the sale of 55,631 net acres, or approximately 6% of our December 31, 2007 total net acres in the Fayetteville Shale play, and related facilities for $518.3 million. Production from the acreage sold was approximately 10.5 MMcf per day at the time of the sale. Additionally, we sold our Gulf Coast and Permian Basin properties in the second and third quarters of 2008. Production from these properties contributed approximately 3.1 Bcfe, 6.1 Bcfe and 8.4 Bcfe to total production in 2008, 2007 and 2006, respectively.

Gas sales to unaffiliated purchasers were up 79% to 188.0 Bcf in 2008 and up 66% to 105.1 Bcf in 2007, compared to the prior years. Sales to unaffiliated purchasers are primarily made under contracts that reflect current short-term prices and are subject to seasonal price swings. Intersegment sales to AWG for the six-month period prior to the sale of the utility were 4.3 Bcf compared to 4.8 Bcf for the full year of 2007. We expect to continue to sell natural gas to the utility through an annual competitive bidding process. Future increases in demand for our gas production are expected to

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come from sales to unaffiliated purchasers. We are unable to predict changes in the market demand and price for natural gas, including weather-related changes affecting demand for our production.

We are targeting 2009 gas and oil production of 280.0 to 284.0 Bcfe, an increase of approximately 45% over our 2008 production. Based on early production histories and modeling, and assuming continued positive exploration and development results, approximately 229.0 to 232.0 Bcf of our 2009 targeted gas production is projected to come from our activities in the Fayetteville Shale play. Although we expect production volumes in 2009 to increase, we cannot guarantee our success in discovering, developing, and producing reserves, including with respect to our Fayetteville Shale play. Our ability to discover, develop and produce reserves is dependent upon a number of factors, many of which are beyond our control, including the availability of capital, the timing and extent of changes in natural gas and oil prices and competition. There are also many risks inherent to the discovery, development and production of natural gas and oil. We refer you to Risk Factors in Item 1A of Part I of this Form 10-K for a discussion of these risks and the impact they could have on our financial condition and results of operations.

Commodity Prices

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 ensure certain desired levels of cash flow and to minimize the impact of price fluctuations, including fluctuations in locational market differentials (we refer you to Item 7A of this Form 10-K and Note 10 to the consolidated financial statements for additional discussion). The average price realized for our gas production, including the effects of hedges, increased 11% to $7.52 per Mcf in 2008 and increased 4% to $6.80 per Mcf in 2007. The change in the average price realized reflects changes in average spot market prices and the effects of our price hedging activities. Our hedging activities decreased the average gas price $0.21 per Mcf in 2008, compared to increases of $0.64 per Mcf in 2007 and $0.18 per Mcf in 2006. In recent years, locational differences in market prices for natural gas have been wider than historically experienced. Disregarding the impact of hedges, historically the average price received for our gas production was approximately $0.30 to $0.50 per Mcf lower than average NYMEX spot market prices due to the locational market differentials. However, during 2008, 2007 and 2006, widening market differentials caused the difference in our average price received for our gas production to be approximately $0.70 to $1.30 per Mcf lower than spot market prices. The discount was at its widest point in late 2008 due to the impact that the delay in the completion of Boardwalk Pipeline had upon the Centerpoint East differential. Assuming a NYMEX commodity price for 2009 of $6.00 per Mcf of gas, the average price received for our gas production is expected to be approximately $0.75 per Mcf below the NYMEX Henry Hub index price, including the impact of our basis hedges. We hedged approximately 73% of our production in 2008 from the impact of widening basis differentials through our hedging activities and sales arrangements. Additionally, at December 31, 2008, we had basis protected on approximately 132.6 Bcf of our 2009 expected gas production through financial hedging activities and physical sales arrangements at a differential to NYMEX gas prices of approximately $0.30 per Mcf.

In addition to the basis hedges discussed above, at December 31, 2008, we had NYMEX commodity price hedges in place on 135.0 Bcf of our 2009 expected future gas production and 50.0 Bcf of our 2010 expected future gas production.

We realized an average price of $107.18 per barrel for our oil production for the year ended December 31, 2008, up approximately 55% from the prior year. The 2007 realized average price of $69.12 per barrel was up 18% from 2006. We did not hedge any of our 2008 or 2007 oil production. The average price we received for our oil production in 2006 was reduced by $4.81 per barrel due to the effects of our hedging activities. Assuming a NYMEX commodity price of $50.00 per barrel of oil for 2009, we expect the average price received for our oil production during 2009 to be approximately $1.50 per barrel lower than average spot market prices as market differentials reduce the average prices received.

Operating Costs and Expenses

Lease operating expenses per Mcfe for the E&P segment were $0.89 in 2008, compared to $0.73 in 2007 and $0.66 in 2006. Lease operating expenses per unit of production increased in 2008 and 2007 due primarily to higher per unit operating costs associated with our Fayetteville Shale operations, including the impact that higher natural gas prices had on the cost of compressor fuel in 2008. Our Fayetteville Shale production is growing rapidly and is expected to continue to provide upward pressure on our per unit operating costs. We expect our per unit operating cost for this segment to range between $0.87 and $0.92 per Mcfe in 2009.

General and administrative expenses for the E&P segment were $0.41 per Mcfe in 2008, down from $0.48 per Mcfe in 2007 and $0.58 per Mcfe in 2006. The decreases in general and administrative costs per Mcfe in 2008 and 2007 were due to the effects of our increased production volumes. In total, general and administrative expenses for the E&P

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segment were $80.2 million in 2008, $54.8 million in 2007 and $41.9 million in 2006. The increases in general and administrative expenses since 2006 were primarily due to increases in payroll, incentive compensation and employee-related costs associated with the expansion of our E&P operations due to the continued development of the Fayetteville Shale play. These increases accounted for $19.7 million, or 78%, of the 2008 increase and $9.4 million, or 73%, of the 2007 increase. We added 145 new E&P employees during 2008, compared to 176 employees added in 2007. In 2008 and 2007, increased expenses associated with leased aircraft and increases in information technology-related expenses accounted for most of the remaining increases in general and administrative expenses. We expect our cost per unit for general and administrative expenses in 2009 to range between $0.32 and $0.37 per Mcfe. The expected decrease in per unit costs in 2009 is due to anticipated increased production volumes from our Fayetteville Shale play. Future changes in our general and administrative expenses for this segment are primarily dependent upon our salary costs, level of pension expense, stock-based compensation expensing under Statement on Financial Accounting Standards No. 123R Share-Based Payment (FAS 123R) and the amount of incentive compensation paid to our employees. For eligible employees, a portion of incentive compensation is based on the achievement of certain operating and performance results, including production, proved reserve additions, present value added for each dollar of capital invested, and lease operating expenses and general and administrative expenses per unit of production, while another portion is discretionary based upon an employee s performance. Additional discretionary awards may also be awarded under the incentive compensation plan. See Critical Accounting Policies below for further discussion of pension expense.

Our full cost pool amortization rate averaged $1.99 per Mcfe for 2008, $2.41 per Mcfe for 2007 and $1.90 per Mcfe for 2006. The decline in the average amortization rate for 2008 was primarily the result of the sales of oil and gas properties in 2008, the proceeds of which were credited to the full cost pool. The amortization rate is impacted by the timing and amount of reserve additions and the costs associated with those additions, revisions of previous reserve estimates due to both price and well performance, write-downs that result from full cost ceiling tests, proceeds from the sale of properties that reduce the full cost pool and the levels of costs subject to amortization. We cannot predict our future full cost pool amortization rate with accuracy due to the variability of each of the factors discussed above, as well as other factors, including but not limited to the uncertainty of the amount of future reserves attributed to our Fayetteville Shale play. Based on recent well performance in the Fayetteville Shale play, we expect the amount of reserves from future wells to continue to increase which would, if all other factors remained constant, decrease our full cost pool amortization rate going forward. Unevaluated costs excluded from amortization were $540.6 million at the end of 2008, compared to $372.4 million at the end of 2007 and $166.8 million at the end of 2006. The increases in unevaluated costs during these periods resulted primarily from the increased activity in our Fayetteville Shale play. See Note 7 to the consolidated financial statements for additional information regarding our unevaluated costs excluded from amortization.

Taxes other than income taxes per Mcfe were $0.13 in 2008, $0.16 in 2007 and $0.30 in 2006, and vary from year to year due to changes in severance and ad valorem taxes that result from the mix of our production volumes and fluctuations in commodity prices. Additionally, we accrued $5.0 million, or $0.03 per Mcfe, in 2008 for severance tax refunds related to our East Texas production, compared to $4.9 million, or $0.04 per Mcfe, in 2007. In April 2008, the State of Arkansas enacted legislation that will increase the severance tax on natural gas produced within the state to a base rate of 5%, effective January 1, 2009, subject to certain periods of reduced rates for high-cost gas wells, new discovery gas wells and gas wells that produce below a specified level. We have evaluated the impact of the increase in the severance taxes with respect to all of our production within the State of Arkansas, including our Fayetteville Shale operations, and expect that our wells will qualify for the reduced rate exceptions noted above. We do not expect it to materially affect our results of operations in 2009 or beyond.

The timing and amount of production and reserve additions attributed to our Fayetteville Shale play could have a material impact on our per unit costs; if production or reserves additions are lower than projected, our per unit costs could increase.

We utilize the full cost method of accounting for costs related to the exploration, development, and acquisition of natural gas and oil reserves. Under this method, all such costs (productive and nonproductive) including salaries, benefits and other internal costs directly attributable to these activities are capitalized and amortized on an aggregate basis over the estimated lives of the properties using the units-of-production method. These capitalized costs are subject to a ceiling test that limits such pooled costs to the aggregate of the present value of future net revenues attributable to proved natural gas and oil reserves discounted at 10 percent (standardized measure) plus the lower of cost or market value of unproved properties. Any costs in excess of the ceiling are written off as a non-cash expense. The expense may not be reversed in future periods, even though higher natural gas and oil prices may subsequently increase the ceiling. Full cost companies must use the prices in effect at the end of each accounting quarter, including the impact of derivatives qualifying as hedges, to calculate the ceiling value of their reserves. However, commodity price increases subsequent to the end of a reporting

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period but prior to the release of periodic reports may be utilized to calculate the ceiling value of reserves. At December 31, 2008, 2007 and 2006, our unamortized costs of natural gas and oil properties did not exceed this ceiling amount. At December 31, 2008, the ceiling value of our reserves was calculated based upon quoted market prices of $5.71 per Mcf for Henry Hub gas and $41.00 per barrel for West Texas Intermediate oil, adjusted for market differentials. Cash flow hedges of gas production in place at December 31, 2008 increased the calculated ceiling value by approximately $338.7 million (net of tax). Excluding the benefit of the cash flow hedges at December 31, 2008, unamortized costs still did not exceed the ceiling value. At December 31, 2007, the ceiling value of our reserves was calculated based upon quoted market prices of $6.80 per Mcf for Henry Hub gas and $92.50 per barrel for West Texas Intermediate oil, and at December 31, 2006, the ceiling value of our reserves was calculated based upon quoted market prices of $5.64 per Mcf for Henry Hub gas and $57.25 per barrel for West Texas Intermediate oil. Decreases in market prices from December 31, 2008 levels, as well as changes in production rates, levels of reserves, the evaluation of costs excluded from amortization, future development costs, and service costs could result in future ceiling test impairments.

Inflation impacts our E&P operations by generally increasing our operating costs and the costs of our capital additions. The effects of inflation on our operations prior to 2000 were minimal. However, since 2001, as commodity prices have generally increased, the impact of inflation has intensified in our E&P segment as shortages in drilling rigs, third-party services and qualified labor have risen due to increased activity levels in the natural gas and oil industry. We have endeavored to mitigate rising costs by obtaining vendor pricing commitments for multiple projects and by offering performance bonuses related to increased economic efficiencies. During 2007, our E&P operations began experiencing decreases in certain costs for third-party services primarily due to increased vendor competition in our Fayetteville Shale operating area. In late 2008, costs for third-party services further declined as competition increased due to decreased activity levels in the natural gas and oil industry as a result of the economic turmoil in the United States and abroad.

Midstream Services

	Year Ended December 31,		
	2008	2007	2006
	(in millions, except volumes)		
Revenues marketing	**$ 2,059.1**	$ 924.3	$ 467.3
Revenues gathering	**$ 114.9**	$ 37.7	$ 7.9
Gas purchases marketing	**$ 2,043.5**	$ 915.1	$ 458.9
Operating costs and expenses	**$ 68.2**	$ 33.7	$ 12.2
Operating income	**$ 62.3**	$ 13.2	$ 4.1
Gas volumes marketed (Bcf)	**258.0**	145.7	72.7
Gas volumes gathered (Bcf)	**224.1**	78.7	14.6

Revenues and Operating Income

Revenues. Revenues from our Midstream Services segment were up 126% to $2.2 billion in 2008 and up 102% to $962.0 million in 2007, as compared to prior years. The increase in marketing revenues for 2008 resulted from a 112.3 Bcf increase in volumes marketed and a 26% increase in the price received for volumes marketed. Approximately 92% of the increase in gathering revenues for 2008 resulted from increases in volumes gathered related to the Fayetteville Shale play. The increase in marketing revenues for 2007 resulted from a 73.0 Bcf increase in volumes marketed largely resulting from increased production from the Fayetteville Shale play, partially offset by a 1% decrease in the price received for volumes marketed. Of the total volumes marketed, production from our E&P operated wells accounted for 96% in 2008, 89% in 2007 and 85% in 2006. Increases and decreases in marketing revenues due to changes in commodity prices are largely offset by corresponding changes in gas purchase expenses. Gathering volumes, revenues and expenses for this segment are expected to continue to grow as reserves related to our Fayetteville Shale play are developed and production increases.

Operating Income. Operating income from our Midstream Services segment increased 371% to $62.3 million in 2008 and 222% to $13.2 million in 2007 as a result of the increases in gathering revenues from the Fayetteville Shale play and increases in the margin generated by gas marketing activities, partially offset by increased operating costs and expenses. The margin generated from natural gas marketing activities was $15.6 million for 2008, compared to $9.2 million for 2007 and $8.4 million for 2006. Margins may fluctuate depending on the prices paid for commodities and the ultimate disposition of those commodities. The increases in volumes marketed in 2008 and 2007, as compared to prior years, resulted from marketing our increased E&P production volumes. We enter into hedging activities from time to time with respect to our gas marketing activities to provide margin protection. We refer you to Quantitative and Qualitative Disclosures about Market Risk and Note 10 to the consolidated financial statements for additional information. As noted above, gathering revenues and expenses are expected to continue to grow as a result of our

Fayetteville Shale activities.

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Our Midstream Services segment has significant commitments for transportation services related to its marketing activities and compression for its gathering activities. See Contractual Obligations and Contingent Liabilities and Commitments below for further discussion.

Natural Gas Distribution

	Year Ended December 31,		
	2008(1)	2007	2006
	($ in thousands, except for per Mcf amounts)		
Revenues	**$ 117,710**	$ 174,466	$ 172,207
Gas purchases	**$ 79,120**	$ 111,338	$ 112,922
Operating costs and expenses	**$ 27,857**	$ 53,168	$ 54,811
Operating income	**$ 10,733**	$ 9,960	$ 4,474
Sales and end-use transportation deliveries (Bcf)	**14.5**	23.6	21.8
Sales customers at year-end	**n/a**	151,988	151,003
Average sales rate per Mcf	**$ 11.61**	$ 11.07	$ 12.30
Annual heating weather degree days	**n/a**	3,699	3,413
Percent of normal	**n/a**	91%	83%

(1)

The 2008 column reflects results for the first six months of 2008 prior to the sale of the utility.

Effective July 1, 2008, we sold all of the capital stock of AWG 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 AWG for the benefit of its customers. A gain on the sale of $57.3 million ($35.4 million after-tax) was recorded in the third quarter of 2008. As a result of the sale of AWG, we no longer have any natural gas distribution operations. The 2008 column in the table above reflects results for the first six months of 2008, which represents the period of our ownership of AWG in 2008.

Transportation

In 2006, we sold our 25% partnership interest in NOARK Pipeline System, Limited Partnership (NOARK) to Atlas Pipeline Partners, L.P. for $69.0 million and recognized a pre-tax gain of approximately $10.9 million ($6.7 million after-tax) relating to the transaction. We recorded pre-tax income from operations related to our investment in NOARK of $0.9 million in 2006. Income from operations and the gain on the sale in the second quarter of 2006 were recorded in other income in our statements of operations.

Other Revenues

In 2008, 2007 and 2006, other revenues included pre-tax gains of $4.8 million, $6.4 million and $4.0 million, respectively, related to the sale of gas-in-storage inventory.

Interest Expense and Interest Income

Interest costs, net of capitalization, increased to $28.9 million in 2008 and to $23.9 million in 2007 due to our increased average levels of borrowings outstanding that resulted from our increased level of capital investments. Our debt level had decreased $243.4 million to $735.4 million by year end 2008 due to cash flow in excess of capital investments generated by the $964.0 million of proceeds received for our asset sales. We refer you to Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources Financing Requirements and Note 3 to the consolidated financial statements for further discussion of our debt. Interest capitalized increased to $34.5 million in 2008, up from $13.8 million in 2007 and $11.8 million in 2006, as our costs excluded from amortization in the E&P segment have continued to increase along with the overall increased level of our capital investments. Costs excluded from amortization in the E&P segment increased to $540.6 million at December 31, 2008, compared to $372.4 million at December 31, 2007. Total capital investments for our E&P segment were $1.6 billion in 2008, up from $1.4 billion in 2007.

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During 2008, 2007 and 2006, we earned interest income of $4.4 million, $0.1 million and $6.3 million, respectively, related to our cash investments. These amounts are recorded in other income on the Statements of Operations.

Income Taxes

Our provision for income taxes was an effective rate of 38.2% for 2008, compared to 38.1% in 2007 and 37.9% in 2006. Any changes in the provision for income taxes recorded each period result primarily from the level of income before income taxes, adjusted for permanent differences. As a result of the gains from the E&P asset sales and the sale of the utility, we used all of our net operating loss carryforward in 2008 and were subject to current taxes of $122.0 million, of which $107.5 million was paid in 2008. We also generated an alternative minimum tax credit in 2008 of $121.5 million which will be utilized to reduce future taxes. We do not expect to be subject to current taxes in 2009.

Pension Expense

We incurred pension costs of $6.5 million in 2008 for our pension and other postretirement benefit plans, compared to $5.3 million in 2007 and $4.0 million in 2006. As a result of the sale of AWG, we transferred pension and other postretirement plan assets and liabilities related to the employees of AWG to the purchaser. Although our net periodic benefit costs for our pension and other postretirement plans were approximately 30% lower in the second half of 2008 compared to the first half of 2008, our pension costs for the year were higher due to the deterioration of the markets in the second half of 2008.

The amount of pension expense recorded is determined by actuarial calculations and is also impacted by the funded status of our plans. During 2008, we contributed $9.8 million to our pension plans and $0.3 million to our other postretirement plans, compared to $6.5 million and $0.4 million, respectively, in 2007. The recent decline in the financial markets may require changes in management s assumptions relative to expected return on plan assets which could, in turn, adversely impact the funded status of our pension plans and increase the amount of future contribution requirements. For further discussion of our pension plans, we refer you to Note 6 to the consolidated financial statements and Critical Accounting Policies below.

Stock-Based Compensation Expense

We recognized expense of $7.6 million and capitalized $3.9 million to gas and oil properties for stock-based compensation in 2008, compared to $5.4 million expensed and $2.6 million capitalized to gas and oil properties in 2007 and $5.2 million expensed and $1.7 million capitalized to gas and oil properties in 2006. We refer you to Note 12 to the consolidated financial statements for additional discussion of our equity based compensation plans. Additionally in 2008, we recorded expense of $0.3 million related to the valuation of company shares held in our non-qualified deferred compensation plan, compared to $0.9 million expensed and $0.6 million capitalized to gas and oil properties in 2007.

Adoption of Accounting Principles

During the first quarter of 2008, we adopted Statement of Financial Accounting Standards No. 157, Fair Value Measurements (FAS 157). FAS 157 defines fair value, establishes a framework for measuring fair value and expands disclosures about fair value measurements. This statement applies to other accounting pronouncements that require or permit fair value measurements, and is effective for financial statements issued for fiscal years beginning after November 15, 2007. In addition to required disclosures, FAS 157 also requires companies to evaluate current measurement techniques. The adoption of FAS 157 had no material impact on our results of operations and financial condition.

During the first quarter of 2008, we adopted Statement of Financial Accounting Standards No. 159, The Fair Value Option for Financial Assets and Financial Liabilities (FAS 159). FAS 159 permits entities to choose to measure many financial instruments and certain other items at fair value and applies to other accounting pronouncements that require or permit fair value measurements. FAS 159 is effective for financial statements issued for fiscal years beginning after November 15, 2007. The adoption of FAS 159 had no impact on our results of operations and financial condition.

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In December 2007, the FASB issued Statement of Financial Accounting Standards No. 160, Noncontrolling Interest in Consolidated Financial Statements, an amendment of ARB No. 51 (FAS 160). FAS 160 will change the financial accounting and reporting of noncontrolling (or minority) interests in consolidated financial statements, and is effective for financial statements issued for fiscal years beginning after December 15, 2008. FAS 160 will impact the presentation of our balance sheet line item Minority Interest related to our Overton partnership, a partnership formed by SEPCO with an investor to drill and complete 14 wells in the Overton Field in East Texas, but is expected to have no material impact on our results of operations and financial condition.

In February 2008, the FASB issued FASB Staff Position FAS 157-2, Effective Date of FASB Statement No. 157 (FSP FAS 157-2). FSP FAS 157-2 delays the effective date of FAS 157 to fiscal years beginning after November 15, 2008 for all nonfinancial assets and nonfinancial liabilities, except those that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually). FSP FAS 157-2 is effective for our fiscal year beginning January 1, 2009. The adoption of FSP FAS 157-2 is not expected to have a material impact on our results of operations and financial condition.

In March 2008, the FASB issued SFAS No. 161, Disclosures about Derivative Instruments and Hedging Activities an amendment of FASB Statement No. 133 (FAS 161). FAS 161 requires enhanced disclosures for derivative instruments and hedging activities that include explanations of how and why an entity uses derivatives, how instruments and the related hedged items are accounted for under FAS 133 and related interpretations, and how derivative instruments and related hedged items affect the entity s financial position, results of operations and cash flows. FAS 161 is effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008. The adoption of FAS 161 is not expected to have a material impact on our results of operations and financial condition.

In October 2008, the FASB issued FASB Staff Position FAS 157-3, Determining the Fair Value of a Financial Asset When the Market for That Asset Is Not Active (FSP FAS 157-3). FSP FAS 157-3 clarifies the application of FAS 157, Fair Value Measurements, when a market for that financial asset is inactive. FSP FAS 157-3 became effective for financial statements upon issuance and its adoption did not have a material impact on our results of operations and financial condition.

Late in 2008, the SEC adopted major revisions to its required oil and gas reporting disclosures which become effective as of January 1, 2010. Among other things, the amendments provide for the use of the 12-month average price, calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period for purposes of both the disclosure and full-cost accounting rules. With respect to accounting pronouncements that currently make reference to a single-day pricing regime with respect to oil and gas reserves, the SEC indicated that it was communicating with the FASB staff to align the standards used in the FASB s pronouncements with the new 12-month average price and that it will consider whether to delay the compliance date based on its discussions with the FASB. The SEC expressed the view that the change from using single-day year-end price to an average price should be treated as a change in accounting principle, or a change in the method of applying an accounting principle, that is inseparable from a change in accounting estimate and that the change would be considered a change in accounting estimate pursuant to Statement of Financial Accounting Standard No. 154 Accounting Changes and Error Corrections (SFAS 154) and accounted for prospectively. The SEC further expressed that the view that any accounting change resulting from the changes in definitions and required pricing assumptions in Rule 4-10 of Regulation S-X should be treated as a change in accounting principle that is inseparable from a change in accounting estimate, not requiring retroactive revision but requiring recognition in the independent auditor s report through the addition of an explanatory paragraph. We will not be able to determine the impact of these amendments on our results of operation or financial condition until the FASB issues its pronouncements.

LIQUIDITY AND CAPITAL RESOURCES

We depend primarily on internally-generated funds, our unsecured revolving credit facility, funds accessed through debt and equity markets and periodic asset sales as our primary sources of liquidity. We may borrow up to $1.0 billion under our revolving credit facility from time to time. The amount available under our revolving credit facility may be increased up to $1.25 billion at any time upon our agreement with our existing or additional lenders. As of December 31, 2008, we had no indebtedness outstanding under our revolving credit facility and at December 31, 2007, we had $842.2 million outstanding under the facility. During 2009, we expect to draw on a portion of the funds available under the facility to fund our planned capital investments (discussed below under Capital Investments), which are expected to exceed the net cash generated by our operations and the remaining net proceeds from our asset sales in 2008.

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On January 16, 2008, we completed a private placement of $600 million of 7.5% Senior Notes due 2018 (discussed below under Financing Requirements). Net proceeds of approximately $591 million from the offering were used to pay outstanding indebtedness under our revolving credit facility.

In the second quarter of 2008, we completed the sale of 55,631 net acres, or approximately 6% of our total net acres in the Fayetteville Shale play, for approximately $518.3 million. Additionally in 2008, we sold various oil and gas properties in the Gulf Coast and the Permian Basin for approximately $240.0 million in the aggregate. Effective July 1, 2008, we closed the previously announced sale of our utility, AWG, to SourceGas, LLC. We received $223.5 million (net of expenses related to the sale) and, in order to receive regulatory approval for the sale and certain related transactions, paid $9.8 million to AWG for the benefit of its customers. We recorded a pre-tax gain on the sale of AWG of $57.3 million in the third quarter of 2008. In total, we received $964.0 million in proceeds from asset sales during 2008 which were utilized to pay down borrowings under our revolving credit facility and fund a portion of our 2008 capital investment program. The remaining proceeds were invested in cash equivalents and will be used to help fund our 2009 capital investments program.

Net cash provided by operating activities increased 86% to $1.2 billion in 2008, due to a $516.3 million increase in net income and adjustments for non-cash expenses. Net cash provided by operating activities increased 45% to $622.7 million in 2007, due to a $237.7 million increase in net income and adjustments for non-cash expenses. For 2008, requirements for our capital investments were funded from our revolving credit facility, cash generated by operating activities and the net proceeds from our asset sales. Net cash from operating activities provided 65% of our cash requirements for capital investments in 2008, 41% in 2007 and 46% in 2006.

At December 31, 2008, our capital structure consisted of 23% debt and 77% equity, and we had $196.3 million in cash and cash equivalents. We believe that our operating cash flow, the remaining proceeds from our asset sales and available funds under our revolving credit facility will be adequate to meet our capital and operating requirements for 2009. The credit status of the financial institutions participating in our revolving credit facility could adversely impact our ability to borrow funds under the facility. While we believe all of the lenders under the facility have the ability to provide funds, we cannot predict whether each will be able to meet its obligation under the facility. Current economic conditions make it difficult to access debt and equity markets for funding. Given the unused capacity on our revolving credit facility and our expectations of cash flow from our future operations, we do not plan on accessing those markets in the near term.

Our cash flow from operating activities is highly dependent upon the market prices that we receive for our gas and oil production. Natural gas and oil prices are subject to wide fluctuations and are driven by market supply and demand factors which are impacted by the overall state of the economy. The price received for our production is also influenced by our commodity hedging activities, as more fully discussed in Note 10 to the consolidated financial statements included in this Form 10-K and Item 7A, Quantitative and Qualitative Disclosures about Market Risk. Our commodity hedging activities are subject to the credit risk of our counterparties being financially unable to complete the transaction. We actively monitor the credit status of our counterparties, performing both quantitative and qualitative assessments based on their credit ratings and credit default swap rates where applicable, and to date have not had any credit defaults associated with our transactions. However, any future failures by one or more counterparties could negatively impact our cash flow from operating activities.

Additionally, our short-term cash flows are dependent on the timely collection of receivables from our customers and partners. We actively manage this risk through credit management activities and, through the date of this filing, have not experienced any significant write-offs for non-collectible amounts. However, any sustained inaccessibility of credit by our customers and partners could adversely impact our cash flows.

Due to the above factors, we are unable to forecast with certainty our future level of cash flow from operations. Accordingly, we will adjust our discretionary uses of cash dependent upon available cash flow.

Capital Investments

Our capital investments increased 19% to approximately $1.8 billion in 2008 and increased 59% in 2007 to approximately $1.5 billion. Capital investments include an increase of $36.2 million in 2008, a reduction of $20.6 million in 2007 and an increase of $88.9 million for 2006 related to the change in accrued expenditures between years. Our E&P segment investments in 2008 were $1.6 billion, up from $1.4 billion in 2007 and $861.0 million in 2006. Capital investments for 2006 included $93.6 million for drilling rigs and related equipment which were subsequently sold and leased back in December 2006.

	2008	2007	2006

		(in thousands)	
Exploration and production			
Exploration and development	**$ 1,569,089**	$ 1,375,204	$ 767,400
Drilling rigs and related equipment	**26,739**	4,453	93,641
	1,595,828	1,379,657	861,041
Midstream services	**183,021**	107,363	48,660
Natural gas distribution	**3,574** (1)	11,375	11,232
Other	**13,745**	4,743	21,474
	$ 1,796,168	$ 1,503,138	$ 942,407

(1)

Natural gas distribution capital investments are through June 30, 2008, prior to the sale of this segment.

Our capital investments for 2009 are planned to be $1.9 billion, consisting of $1.6 billion for E&P, $220 million for Midstream Services and $40 million for other corporate purposes. We expect to allocate approximately $1.3 billion of our 2009 E&P capital to our Fayetteville Shale play, up from approximately $1.2 billion in 2008. Our planned level of capital investments in 2009 is expected to allow us to accelerate our drilling activity in the Fayetteville Shale, continue the development of our properties in East Texas, continue our conventional drilling in the Arkoma Basin, maintain our present markets, explore and develop other existing gas and oil properties and generate new drilling prospects. As discussed above, our 2009 capital investment program is expected to be funded through cash flow from operations, borrowings under our credit facility and the remaining net proceeds from our 2008 asset sales. The planned capital program for 2009 is flexible and can be modified, including downward, if the low natural gas price environment persists for an extended period of time. We will reevaluate our proposed investments as needed to take into account prevailing market conditions.

Financing Requirements

Our total debt outstanding was $735.4 million at December 31, 2008, including $61.2 million classified as short-term debt on our balance sheet, compared to $978.8 million at December 31, 2007. Our 7.625% Senior Notes due 2027 are putable by the note holders on May 1, 2009, and as a result, the $60 million principal balance of these notes has been reclassified to short-term debt in our balance sheet. If the put option is exercised in 2009, we would use cash available to pay the notes, or alternatively, we would borrow the required funds under our revolving credit facility. Our unsecured revolving credit facility has a borrowing capacity of $1.0 billion, which may be increased to $1.25 billion at any time upon our agreement with our existing or additional lenders. As of December 31, 2008, we had no indebtedness outstanding under our revolving credit facility compared to $842.2 million outstanding as of December 31, 2007. As discussed more fully below, in January 2008, we issued $600 million of 7.5% Senior Notes due 2018, the net proceeds of which were used to repay amounts outstanding under our revolving credit facility. The interest rate on the credit facility is calculated based upon our public debt rating and is currently 87.5 basis points over LIBOR. The revolving credit facility is currently guaranteed by our subsidiaries, SEECO, Inc. (SEECO), Southwestern Energy Production Company (SEPCO) and Southwestern Energy Services Company (SES) and requires additional subsidiary guarantors if certain guaranty coverage levels are not satisfied. Our publicly traded notes are rated BB+ by Standard and Poor s and we have a Corporate Family Rating of Ba2 by Moody s. Any downgrades in our public debt ratings could increase our cost of funds under the credit facility.

Our revolving credit facility contains covenants which impose certain restrictions on us. Under the credit agreement, we may not issue total debt in excess of 60% of our total capital, must maintain a certain level of stockholders equity and must maintain a ratio of EBITDA to interest expense of 3.5 or above. Additionally, there are certain limitations on the amount of indebtedness that may be incurred by our subsidiaries. We were in compliance with all of the covenants of our credit agreement at December 31, 2008. Although we do not anticipate any violations of our financial covenants, our ability to comply with those covenants is dependent upon the success of our exploration and development program and upon factors beyond our control, such as the market prices for natural gas and oil. If we are unable to borrow under our credit facility, we would have to decrease our capital investment plans.

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On January 16, 2008, we issued $600 million of 7.5% Senior Notes due 2018 in a private placement, which are rated BB+ by Standard and Poor s and Ba2 by Moody s. If we undergo a change of control, as defined in the indenture, holders of the 7.5% Senior Notes will have the option to require us to purchase all or any portion of the notes at a purchase price equal to 101% of the principal amount of the notes to be purchased plus any accrued and unpaid interest to, but excluding, the change of control date. Payment obligations with respect to the 7.5% Senior Notes are currently guaranteed by SEECO, SEPCO and SES, which guarantees may be unconditionally released in certain circumstances. As a result of the issuance of the guarantees of the 7.5% Senior Notes, and in order for all of our senior notes to rank equally, on May 2, 2008, we and our subsidiaries, SEECO, SEPCO and SES, entered into supplemental indenture agreements with the trustees under the indentures relating to our 7.625% Medium-Term Notes due 2027, 7.125% Fixed Rate Notes due October 10, 2017, 7.35% Fixed Rate Notes due October 2, 2017 and 7.15% Notes due 2018, pursuant to which SEECO, SEPCO and SES became guarantors of such notes to the same extent to which such subsidiaries have guaranteed our 7.5% Senior Notes. We refer you to Note 4, "Condensed Consolidating Financial Information" in this Form 10-K for additional information. The indentures governing our senior notes contain covenants that, among other things, restrict our ability and/or our subsidiaries ability to incur liens, to engage in sale and leaseback transactions and to merge, consolidate or sell assets.

At December 31, 2008, our capital structure consisted of 23% debt and 77% equity, and we had available $196.3 million in cash and cash equivalents. Our debt as a percentage of total capital declined throughout 2008, primarily due to our operating results and the use of a portion of the proceeds received from our asset sales to reduce debt. Stockholders equity at December 31, 2008, includes a net gain of $258.9 million in accumulated other comprehensive income related to our hedging activities that is required to be recorded under the provisions of Statement on Financial Accounting Standards No. 133, Accounting for Derivative Instruments and Hedging Activities (FAS 133), and a loss of $10.9 million related to changes in our pension and other postretirement liabilities recorded under the provisions of Statement on Financial Accounting Standards No. 158, Employers Accounting for Defined Benefit Pension and Other Postretirement Plans (FAS 158). The amount recorded for FAS 133 is based on current fair values of our hedges at December 31, 2008, and does not necessarily reflect the value that we will receive or pay when the hedges are ultimately settled, nor does it take into account revenues to be received associated with the physical delivery of sales volumes hedged. Our credit facility s financial covenants with respect to capitalization percentages exclude the effects of non-cash entries that result from FAS 133 and FAS 158 and the non-cash impact of any full cost ceiling write-downs. Our capital structure at December 31, 2008 would have been 25% debt and 75% equity without consideration of accumulated other comprehensive income in stockholders equity related to our commodity hedge position and our pension and other postretirement liabilities.

As part of our strategy to ensure a certain level of cash flow to fund our operations, we have hedged 135.0 Bcf of our expected 2009 gas production and 50.0 Bcf of our expected 2010 gas production. The amount of long-term debt we incur will be dependent upon commodity prices and our capital investment plans. If commodity prices significantly decrease, we may decrease and/or reallocate our planned capital investments.

Off-Balance Sheet Arrangements

In December 2006, we entered into a sale and leaseback transaction pursuant to which we sold 13 operating drilling rigs, 2 rigs yet to be delivered and related equipment and then leased such drilling rigs and equipment under leases that expire on January 1, 2015. Subject to certain conditions, we have options to purchase the rigs and related equipment from the lessors at the end of the 84th month of the lease term at an agreed upon price or at the end of the lease term for the then fair market value. Additionally, we have the option to renew each lease for a negotiated renewal term at a periodic rental equal to the fair market rental value of the rigs as determined at the time of renewal. In 2007, we sold and leased back additional drilling rig equipment receiving proceeds of $3.1 million, and leased an additional $5.9 million of drilling rig equipment, under similar terms as the 2006 transaction. In December 2008, pursuant to the terms of the lease, one of the lessors required us to pay $10.5 million, the stipulated loss value, for a rig that suffered a casualty. The payment of the stipulated loss value is treated as a purchase of the rig and is reflected in capital investments within the statement of cash flows. Our current aggregate annual rental payment for drilling rigs and related equipment under the leases is approximately $19.4 million.

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Contractual Obligations and Contingent Liabilities and Commitments

We have various contractual obligations in the normal course of our operations and financing activities. Significant contractual obligations at December 31, 2008, were as follows:

Contractual Obligations:

	Payments Due by Period				
	Total	Less than 1 Year	1 to 3 Years	3 to 5 Years	More than 5 Years
			(in thousands)		
Demand charges[1]	**$ 892,429**	$ 72,878	$ 192,557	$ 168,338	$ 458,656
Debt[2]	**735,400**	61,200	2,400	2,400	669,400
Interest on senior notes[3]	**455,908**	51,931	100,530	100,187	203,260
Rig leases[4]	**116,261**	19,377	38,754	38,754	19,376
Purchase obligations[5]	**101,443**	101,443			
Compression services[6]	**92,075**	26,413	46,272	19,390	
Operating leases[7]	**71,642**	15,398	24,286	17,356	14,602
Operating agreements[8]	**41,968**	38,716	3,252		
Other obligations[9]	**31,817**	27,037	4,780		
	$2,538,943	$ 414,393	$ 412,831	$ 346,425	$ 1,365,294

(1) Our Midstream Services segment has commitments for demand transportation charges of approximately $888.1 million related to the Fayetteville Shale play and approximately $3.0 million related to East Texas. Our E&P segment has commitments for approximately $1.3 million of demand transportation charges.

(2) Debt includes $60.0 million of our 7.625% Senior Notes that are putable at the holders option in May 2009 and $35.4 million of our 7.15% Notes due 2018 which requires semi-annual principal payments of $0.6 million.

(3) Interest on the senior notes includes interest through May 2009 on the $60 million notes that are due in 2027 and putable at the holders option.

(4) We have commitments related to the leasing of 14 drilling rigs and related equipment through 2014.

(5) Purchase obligations consist of outstanding purchase orders under existing agreements. Our Midstream Services segment has outstanding purchase obligations of $81.5 million relating to compression units, $61.7 million of which have been assigned to financial institutions in connection with anticipated lease arrangements. At December 31, 2008, the financial institutions had advanced approximately $20.7 million for payments of these purchase obligations and we pay interest on the advanced amounts.

(6) Our Midstream Services segment has commitments of approximately $84.6 million and our E&P segment has commitments of approximately $7.4 million for compression services associated primarily with our Fayetteville Shale play and our Overton operations.

(7) Operating leases include costs for compressors, aircraft, office space and equipment under non-cancelable operating leases expiring through 2018.

(8) Our E&P segment has commitments for up to $36.3 million in termination fees related to rig operator agreements. Additionally, our E&P segment has secured rig moving services by committing monthly take-or-pay amounts of $469,000, expiring in December 2009.

(9) Our other significant contractual obligations include approximately $16.0 million related to seismic services, approximately $6.1 million for funding of benefit plans and approximately $2.8 million for various information technology support and data subscription agreements. Additionally, our E&P segment has committed up to $3.0 million in termination fees to a gravel company.

We refer you to Note 3 to the consolidated financial statements for a discussion of the terms of our debt.

Contingent Liabilities and Commitments

Substantially all of our employees are covered by defined benefit and postretirement benefit plans. Based on actuarial data and taking into account the transfer of pension assets and obligations related to the sale of AWG, we recorded expenses of approximately $6.5 million in 2008 for these plans. At December 31, 2008, we recognized a liability of $15.4 million as a result of the underfunded status of our pension and other postretirement benefit plans, compared to a liability of $14.6 million at December 31, 2007. As a result of actuarial data, we expect to record expenses of $7.1 million for these plans in 2009. For further information regarding our pension and other postretirement benefit plans, we refer you to Note 6 to the consolidated financial statements and Critical Accounting Policies below for additional information.

Pursuant to the precedent agreement with Texas Gas Transmission, LLC (Texas Gas), a subsidiary of Boardwalk Pipeline Partners, LP, in the third quarter of 2008, SES entered into firm transportation agreements with Texas Gas relating to its commitments for the Fayetteville and Greenville Laterals. SES options to increase the volumes to be transported on

each of the laterals were fully exercised in 2008 and 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. SES obligations under these agreements are reflected in the Contractual Obligations table above. In addition, we have guaranteed a portion of SES obligations under the firm transportation agreements with Texas Gas. Our payment obligations under the guaranty are limited to the lesser of (i) 25% of SES negotiated demand charges for the full term of the agreement(s), less any payments made by us pursuant to the guaranty, or (ii) 25% of SES negotiated demand charges for the remaining initial terms of the agreement(s) as of the first day of the month of services under the agreements for which payment is claimed, which amount shall reflect any reductions in SES obligations under the agreements.

In September 2008, SES entered into a precedent agreement pursuant to which it will contract for firm gas transportation services on a proposed new pipeline of Fayetteville Express Pipeline LLC (FEP), which is jointly owned by Kinder Morgan Energy Partners, L.P. and Energy Transfer Partners, L.P. SES will be a foundation shipper for the project and will use the new pipeline primarily to deliver gas volumes produced from our operations in the Fayetteville Shale play in central Arkansas to eastern markets. Pending regulatory approvals, the pipeline is expected to have an estimated ultimate capacity of up to 2.0 Bcf per day and to be in-service by late 2010 or early 2011. Following the approval of the pipeline by the Federal Energy Regulatory Commission (FERC) and subject to certain conditions, pursuant to the precedent agreement, SES will enter into a firm transportation agreement to transport up to 1,200,000 Dekatherms per day for an initial term of ten years. In connection with the precedent agreement, we delivered to FEP a guaranty of SES obligations under the precedent agreement and the firm transportation agreements to be entered into thereunder. Initially, and during any period in which SES meets the creditworthiness requirements of the precedent agreement, our payment obligations under the guaranty are zero but will increase upon the occurrence of certain events.

In the fourth quarter of 2008, one of our gathering subsidiaries, DeSoto Gathering Company, L.L.C. (DGC), entered into agreements with financial institutions in contemplation of leasing up to 50 compression units pursuant to which those institutions were assigned $61.7 million of our purchase obligations for the units and provided advances for payment of those obligations. At December 31, 2008, the financial institutions had advanced $20.7 million with respect to the purchase obligations and we will pay interest on the advanced amounts until the leases commence. The commencement of the leases is contingent upon certain criteria including, but not limited to, the delivery of the compressors. If the leases do not commence, we must repay all advances and the purchase obligations for the compression units revert back to us. Purchase obligations and interim interest obligations relating to compression units are reflected in the Contractual Obligations table above. We expect to begin receiving the units in the first quarter of 2009, with all of the units expected to be delivered by the end of 2009. Aggregate rental payments, including interim interest, are expected to total approximately $60.1 million over the terms of the leases, which will vary between seven and eight years. In addition, we have guaranteed DGC s obligations under the advances and the anticipated leases subject to an aggregate cap of $100 million.

We are subject to litigation and claims (including with respect to environmental matters) that arise 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, at which time management may reserve amounts that are reasonably estimable.

Working Capital

We maintain access to funds that may be needed to meet capital requirements through our revolving credit facility described above. We had positive working capital of $96.4 million at December 31, 2008, and negative working capital of $67.6 million at December 31, 2007. Current assets increased $525.9 million at December 31, 2008, compared to current assets at December 31, 2007, due to a $278.8 million increase in our current hedging asset, a $195.6 million increase in cash and cash equivalents from proceeds remaining from the sale of our utility segment and certain oil and gas assets, and a $76.9 million increase in accounts receivable, which were partially offset by a decrease of $58.9 million in current assets held for sale related to our utility segment. Current liabilities increased $362.0 million as a result of an increase of $151.1 million in accounts payable, an increase of $101.5 million in our current deferred income taxes related to our hedging activities, a $60.0 million increase due to the reclassification of our 7.625% Senior Notes to short-term, a $38.6 million increase in advances from partners, a $26.9 million increase in current taxes payable and an increase of $18.6 million in interest payable.

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CRITICAL ACCOUNTING POLICIES

Natural Gas and Oil Properties

We utilize the full cost method of accounting for costs related to the exploration, development and acquisition of natural gas and oil reserves. Under this method, all such costs (productive and nonproductive), including salaries, benefits and other internal costs directly attributable to these activities are capitalized and amortized on an aggregate basis over the estimated lives of the properties using the units-of-production method. These capitalized costs are subject to a ceiling test that limits such pooled costs to the aggregate of the present value of future net revenues attributable to proved natural gas and oil reserves discounted at 10 percent (standardized measure) plus the lower of cost or market value of unproved properties. Any costs in excess of the ceiling are written off as a non-cash expense. The expense may not be reversed in future periods, even though higher natural gas and oil prices may subsequently increase the ceiling. Full cost companies must use the prices in effect at the end of each accounting quarter, including the impact of derivatives qualifying as hedges, to calculate the ceiling value of their reserves. However, commodity price increases subsequent to the end of a reporting period but prior to the release of periodic reports may be utilized to calculate the ceiling value of reserves. At December 31, 2008, 2007 and 2006, our unamortized costs of natural gas and oil properties did not exceed this ceiling amount. At December 31, 2008, the ceiling value of our reserves was calculated based upon quoted market prices of $5.71 per Mcf for Henry Hub gas and $41.00 per barrel for West Texas Intermediate oil, adjusted for market differentials. Cash flow hedges of gas production in place at December 31, 2008, increased the calculated ceiling value by approximately $338.7 million (net of tax). Excluding the benefit of the cash flow hedges at December 31, 2008, unamortized costs still did not exceed the ceiling value. We had approximately 185.0 Bcf of future gas production hedged at December 31, 2008. At December 31, 2007, the ceiling value of our reserves was calculated based upon quoted market prices of $6.80 per Mcf for Henry Hub gas and $92.50 per barrel for West Texas Intermediate oil, and at December 31, 2006, the ceiling value of our reserves was calculated based upon quoted market prices of $5.64 per Mcf for Henry Hub gas and $57.25 per barrel for West Texas Intermediate oil. Decreases in market prices from December 31, 2008 levels, as well as changes in production rates, levels of reserves, the evaluation of costs excluded from amortization, future development costs, and service costs could result in future ceiling test impairments.

The risk that we will be required to write-down the carrying value of our natural gas and oil properties increases when natural gas and oil prices are depressed or if there are substantial downward revisions in estimated proved reserves. Under the SEC s current full cost accounting rules, our reserves are required to be priced using prices in effect at the end of the reporting period. Application of these rules during periods of relatively low natural gas or oil prices due to seasonality or other reasons, even if temporary, increases the probability of a ceiling test write-down. Natural gas pricing has historically been unpredictable and any declines could result in a ceiling test write-down in subsequent quarterly or annual reporting periods. Under new rules recently issued by the SEC that will be effective January 1, 2010, reserves will be priced using the 12-month average price, calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period.

Natural gas and oil reserves used in the full cost method of accounting cannot be measured exactly. Our estimate of natural gas and oil reserves requires extensive judgments of reservoir engineering data 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. These estimates are reviewed by senior engineers who are not part of the asset management teams and our President and Chief Operating Officer. Final authority over the estimates of our proved reserves rests with our Board of Directors. In each of the past three years, performance revisions to our proved reserve estimates represented no greater than 8% of our total proved reserve estimates, which we believe is indicative of the effectiveness of our internal controls. Proved developed reserves generally have a higher degree of accuracy in this estimation process, when compared to proved undeveloped and proved non-producing reserves, as production history and pressure data over time is available for the majority of our proved developed properties. Proved developed reserves account for 62% of our total reserve base at December 31, 2008. Assigning monetary values to such estimates does not reduce the subjectivity and changing nature of such reserve estimates. The uncertainties inherent in the reserve estimates are compounded by applying additional estimates of the rates and timing of production and the costs that will be incurred in developing and producing the reserves. We cannot assure you that our internal controls sufficiently address the numerous uncertainties and risks that are inherent in estimating quantities of natural gas and oil reserves and projecting future rates of production and timing of development expenditures as many factors are beyond our control. We refer you to Although our estimated natural gas and oil reserve data is independently audited, our estimates may still prove to be inaccurate in Item 1A, Risk Factors, of Part I of this Form 10-K for a more detailed discussion of these uncertainties, risks and other factors.

We engage the services of Netherland, Sewell & Associates, Inc., an independent petroleum engineering firm, or NSA, to audit our reserves as estimated by our reservoir engineers. NSA reports the results of the reserves audit to our Board of Directors. In conducting its audit, the engineers and geologists of NSA study our major properties in detail and independently develop reserve estimates. NSA s audit consists primarily of substantive testing, which includes a detailed review of major properties that account for approximately 83% of present worth of the company's total proved reserves. NSA 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 not reviewed in the audit. The fields included in approximately the top 83% present value as of December 31, 2008, accounted for approximately 83% of our total proved reserves and approximately 92% of our proved undeveloped reserves. In the conduct of its audit, NSA did not independently verify the data we provided to them with respect to ownership interests, oil and gas production, well test data, historical costs of operation and development, product prices, or any agreements relating to current and future operations of the properties and sales of production. NSA 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, NSA 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. For the year-ended December 31, 2008, NSA issued its audit opinion as to the reasonableness of our reserve estimates, stating that our estimated proved oil and gas reserves are, in the aggregate, reasonable and have been prepared in accordance with generally accepted petroleum engineering and evaluation principles.

A decline in gas and oil prices used to calculate the discounted future net revenues of our reserves affects both the present value of cash flows and the quantity of reserves reported. Our reserve base is nearly 100% natural gas, therefore changes in oil prices used do not have as significant an impact as gas prices on cash flows and reported reserve quantities. Reported discounted cash flows and reserve quantities at December 31, 2008, were $2,109.3 million and 2,184.6 Bcfe, respectively. An assumed decrease of $1.00 per Mcf in the December 31, 2008 gas price used to price our reserves would have resulted in an approximate $503.1 million decline in our future net cash flows discounted at 10%, adjusted for the effects of commodity hedges, and an approximate decrease of 23 Bcfe of our reported reserves. The decline in reserve quantities, assuming this decrease in gas price, would have the impact of increasing our unit of production amortization of the full cost pool. The unit of production rate for amortization is adjusted quarterly based on changes in reserve estimates and capitalized costs.

Hedging

We use natural gas and crude oil swap agreements and options to reduce the volatility of earnings and cash flow due to fluctuations in the prices of natural gas and oil. Our policies prohibit speculation with derivatives and limit agreements to counterparties with appropriate credit standings to minimize the risk of uncollectability. We actively monitor the credit status of our counterparties, performing both quantitative and qualitative assessments based on their credit ratings and credit default swap rates where applicable, and to date have not had any credit defaults associated with our transactions. In recent years, we have hedged 60% to 80% of our annual production. The primary market risks related to our derivative contracts are the volatility in market prices and basis differentials for natural gas and crude oil. However, the market price risk is generally offset by the gain or loss recognized upon the related gas or oil transaction that is hedged.

Our derivative instruments are accounted for under FAS 133, as amended, and are recorded at fair value in our financial statements. We have established the fair value of derivative instruments using data provided by our counterparties in conjunction with assumptions evaluated internally using established index prices and other sources. These valuations are recognized as assets or liabilities in our balance sheet and, to the extent an open position is an effective cash flow hedge on equity production, the offset is recorded in other comprehensive income. Results of settled commodity hedging transactions are reflected in natural gas and oil sales or in gas purchases. Any derivative not qualifying for hedge accounting treatment or any ineffective portion of a properly designated hedge is recognized immediately in earnings. For the year ended December 31, 2008, we recorded an unrealized gain of $2.5 million related to basis differential swaps that did not qualify for hedge accounting in addition to a $7.0 million loss related to the change in estimated ineffectiveness of our commodity cash flow hedges. Future market price volatility could create significant changes to the hedge positions recorded in our financial statements. We did not enter into any interest rate swaps in 2008, 2007 or 2006. We refer to you to Quantitative and Qualitative Disclosures about Market Risk in Item 7A of Part II of this Form 10-K for additional information regarding our hedging activities.

Pension and Other Postretirement Benefits

We record our prepaid or accrued benefit cost, as well as our periodic benefit cost, for our pension and other postretirement benefit plans using measurement assumptions that we consider reasonable at the time of calculation (see Note 6 to the consolidated financial statements for further discussion and disclosures regarding these benefit plans). Two of

the assumptions that affect the amounts recorded are the discount rate, which estimates the rate at which benefits could be effectively settled, and the expected return on plan assets, which reflects the average rate of earnings expected on the funds invested. For the December 31, 2008, benefit obligation and the periodic benefit cost to be recorded in 2009, the discount rate assumed is 6.0%. For the 2009 periodic benefit cost, the expected return assumed is 7.50%. This compares to a discount rate of 6.0% and an expected return of 7.75% used in 2008.

Using the assumed rates discussed above, we recorded pension expense of $6.5 million in 2008, $5.3 million in 2007 and $4.0 million in 2006 related to our pension and other postretirement benefit plans. As a result of the sale of AWG on July 1, 2008, we transferred pension and other postretirement assets and liabilities related to the employees of AWG to the purchaser. At December 31, 2008 we recognized a liability of $15.4 million, compared to $14.6 million at December 31, 2007, related to our pension and other postretirement benefit plans. During 2008, we also funded $10.1 million to our pension and other postretirement benefit plans. In 2009, we expect to fund $6.1 million to our pension and other postretirement benefit plans and recognize pension expense of $6.2 million and a postretirement benefit expense of $0.9 million. Assuming a 1% change in the 2008 rates (lower discount rate and lower rate of return), we would have recorded pension and other postretirement benefit expense of $7.9 million in 2008.

Gas in Underground Storage

We currently have one facility owned by our E&P segment that contains gas in underground storage. Gas in storage that is expected to be cycled within the next 12 months is recorded in current assets. This current portion of gas in storage is classified as inventory and is carried at the lower of cost or market. At December 31, 2008 and 2007, the current portion of gas in storage was $24.1 million and $25.0 million, respectively. The non-current portion of gas in storage is classified in property, plant and equipment and carried at cost. The carrying value of the non-current gas is evaluated for recoverability whenever events or changes in circumstances indicate that it may not be recoverable.

The gas in inventory for the E&P segment is used primarily to supplement production in meeting the segment's contractual commitments, including delivery to customers of AWG, especially during periods of colder weather. As a result, demand fees paid by AWG to our E&P subsidiaries are a part of the realized price of the gas in storage. In determining the lower of cost or market for storage gas, we utilize the gas futures market in assessing the price we expect to be able to realize for our gas in inventory. A significant decline in the future market price of natural gas could result in a write-down of our gas in storage carrying cost.

See further discussion of our significant accounting policies in Note 1 to the consolidated financial statements.

CAUTIONARY STATEMENT ABOUT FORWARD-LOOKING STATEMENTS

All statements, other than historical fact or present financial information, may be deemed to be forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. All statements that address activities, outcomes and other matters that should or may occur in the future, including, without limitation, statements regarding the financial position, business strategy, production and reserve growth and other plans and objectives for our future operations, are forward-looking statements. Although we believe the expectations expressed in such forward-looking statements are based on reasonable assumptions, such statements are not guarantees of future performance. We have no obligation and make no undertaking to publicly update or revise any forward-looking statements, except as may be required by law.

Forward-looking statements include the items identified in the preceding paragraph, information concerning possible or assumed future results of operations and other statements in this Form 10-K identified by words such as anticipate, project, intend, estimate, expect, believe, predict, budget, projection, goal, plan, forecast, targ

You should not place undue reliance on forward-looking statements. They are subject to known and unknown risks, uncertainties and other factors that may affect our operations, markets, products, services and prices and cause our actual results, performance or achievements to be materially different from any future results, performance or achievements expressed or implied by the forward-looking statements. In addition to any assumptions and other factors referred to specifically in connection with forward-looking statements, risks, uncertainties and factors that could cause our actual results to differ materially from those indicated in any forward-looking statement include, but are not limited to:

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the timing and extent of changes in market conditions and prices for natural gas and oil (including regional basis differentials);

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our ability to transport our production to the most favorable markets or at all;

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the timing and extent of our success in discovering, developing, producing and estimating reserves;

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the economic viability of, and our success in drilling, our large acreage position in the Fayetteville Shale play overall as well as relative to other productive shale gas plays;

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our ability to fund our planned capital investments;

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

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

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the costs and availability of oilfield personnel services and drilling supplies, raw materials, and equipment and services, including pressure pumping equipment and crews in the Arkoma basin;

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our future property acquisition or divestiture activities;

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the effects of weather;

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increased competition;

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the financial impact of accounting regulations and critical accounting policies;

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the comparative cost of alternative fuels;

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conditions in capital markets, changes in interest rates and the ability of our lenders to provide us with funds as agreed;

·

credit risk relating to the risk of loss as a result of non-performance by our counterparties, and;

·

any other factors listed in the reports we have filed and may file with the SEC.

We caution you that forward-looking statements contained in this Form 10-K are subject to all of the risks and uncertainties, many of which are beyond our control, incident to the exploration for and development, production and sale of natural gas and oil. These risks include, but are not limited to, commodity price volatility, third-party interruption of sales to market, inflation, lack of availability of goods and services, environmental risks, drilling and other operating risks, regulatory changes, the uncertainty inherent in estimating proved natural gas and oil reserves and in projecting future rates of production and timing of development expenditures and the other risks described in Item 1A of Part I of this Form 10-K.

Estimates of our proved natural gas and oil reserves and the estimated future net revenues from such reserves in this Form 10-K are based upon various assumptions, including assumptions required by the SEC relating to natural gas and oil prices, drilling and operating expenses, capital investments, taxes and availability of funds. The process of estimating natural gas and oil reserves is complex. This process requires significant decisions and assumptions in the evaluation of available geological, geophysical, engineering and economic data for each reservoir. Therefore, those estimates are inherently imprecise.

Actual future production, natural gas and oil prices, revenues, taxes, development investments, operating expenses and quantities of recoverable natural gas and oil reserves will most likely vary from those estimated. Such variances may be material. Any significant variance could materially affect the estimated quantities and present value of reserves set forth in this Form 10-K. Our properties may also be susceptible to hydrocarbon drainage from production by other operators on adjacent properties. In addition, we may adjust estimates of proved reserves to reflect production history, results of exploration and development, prevailing natural gas and oil prices and other factors, many of which are beyond our control.

At December 31, 2008, approximately 38% of our estimated proved reserves were proved undeveloped and 3% were proved developed non-producing. Proved undeveloped reserves and proved developed non-producing reserves, by their nature, are less certain than proved developed producing reserves. Estimates of reserves in the non-producing categories are nearly always based on volumetric calculations rather than the performance data used to estimate producing reserves. Recovery of proved undeveloped reserves requires significant capital expenditures and successful drilling operations. Recovery of proved developed non-producing reserves requires capital expenditures to recomplete into the zones behind pipe and is subject to the risk of a successful recompletion. Production revenues from proved undeveloped and proved developed non-producing reserves will not be realized, if at all, until sometime in the future.

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The reserve data assumes that we will make significant capital investments to develop our reserves. Although we have prepared estimates of our natural gas and oil reserves and the costs associated with these reserves in accordance with industry standards, we cannot assure you that the estimated costs are accurate, that development will occur as scheduled or that the actual results will be as estimated.

You should not assume that the present value of future net cash flows referred to in this Form 10-K is the current fair value of our estimated natural gas and oil reserves. In accordance with SEC requirements, the estimated discounted future net cash flows from proved reserves are generally based on prices and costs as of the date of the estimate. Actual future prices and costs may be materially higher or lower than the prices and costs as of the date of the estimate. Any changes in consumption by gas purchasers or in governmental regulations or taxation could also affect actual future net cash flows. The timing of both the production and the expenses from the development and production of natural gas and oil properties will affect the timing of actual future net cash flows from proved reserves and their present value. In addition, the 10% discount factor, which is required by the SEC to be used in calculating discounted future net cash flows for reporting purposes, is not necessarily the most accurate discount factor for our company.

Should one or more of the risks or uncertainties described above or elsewhere in this Form 10-K occur, or should underlying assumptions prove incorrect, our actual results and plans could differ materially from those expressed in any forward-looking statements. We specifically disclaim all responsibility to publicly update any information contained in a forward-looking statement or any forward-looking statement in its entirety and therefore disclaim any resulting liability for potentially related damages.

All forward-looking statements attributable to us are expressly qualified in their entirety by this cautionary statement.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Market risks relating to our operations result primarily from the volatility in commodity prices, basis differentials and interest rates, as well as credit risk concentrations. We use natural gas and crude oil swap agreements and options and interest rate swaps to reduce the volatility of earnings and cash flow due to fluctuations in the prices of natural gas and oil and in interest rates. Our Board of Directors has approved risk management policies and procedures to utilize financial products for the reduction of defined commodity price risk. Utilization of financial products for the reduction of interest rate risks is subject to the approval of our Board of Directors. These policies prohibit speculation with derivatives and limit swap agreements to counterparties with appropriate credit standings.

Credit Risk

Our financial instruments that are exposed to concentrations of credit risk consist primarily of trade receivables and derivative contracts associated with commodities trading. Concentrations of credit risk with respect to receivables are limited due to the large number of our customers and their dispersion across geographic areas. No single customer accounted for greater than 6% of accounts receivable at December 31, 2008. See Commodities Risk below for discussion of credit risk associated with commodities trading.

Interest Rate Risk

The following table presents the principal cash payments for our debt obligations and related weighted-average interest rates by expected maturity dates. At December 31, 2008, we had $735.4 million of total debt with a weighted average interest rate of 7.48% and we had no indebtedness outstanding under our revolving credit facility. Interest rate swaps may be used to adjust interest rate exposures when deemed appropriate. We do not have any interest rate swaps in effect currently. Our 7.625% Senior Notes due 2027 are putable by the note holders on May 1, 2009, and as a result, the $60 million principal balance of these notes is included in the 2009 expected maturity below.

	Expected Maturity Date							Fair Value
	2009	2010	2011	2012	2013	Thereafter	Total	12/31/08
	($ in millions)							
Fixed Rate	$ 61.2	$ 1.2	$ 1.2	$ 1.2	$ 1.2	$ 669.4	$ 735.4	$ 648.6
Average Interest Rate	7.62%	7.15%	7.15%	7.15%	7.15%	7.47%	7.48%	

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Commodities Risk

We use over-the-counter natural gas and crude oil swap agreements and options to hedge sales of our production and to hedge activity in our Midstream Services segment against the inherent price risks of adverse price fluctuations or locational pricing differences between a published index and the NYMEX futures market. These swaps and options include (1) transactions in which one party will pay a fixed price (or variable price) for a notional quantity in exchange for receiving a variable price (or fixed price) based on a published index (referred to as price swaps), (2) transactions in which parties agree to pay a price based on two different indices (referred to as basis swaps), and (3) the purchase and sale of index-related puts and calls (collars) that provide a "floor" price below which the counterparty pays funds equal to the amount by which the price of the commodity is below the contracted floor, and a "ceiling" price above which we pay to the counterparty the amount by which the price of the commodity is above the contracted ceiling.

The primary market risks relating to our derivative contracts are the volatility in market prices and basis differentials for natural gas and crude oil. However, the market price risk is generally offset by the gain or loss recognized upon the related gas or oil transaction that is hedged. Credit risk relates to the risk of loss as a result of non-performance by our counterparties. The counterparties are primarily major investment and commercial banks which management believes present minimal credit risks. The credit quality of each counterparty and the level of financial exposure we have to each counterparty are closely monitored to limit our credit risk exposure. Additionally, we perform both quantitative and qualitative assessments of these counterparties based on their credit ratings and credit default swap rates where applicable. We did not incur any losses in 2008 related to non-performance of these counterparties and do not anticipate any losses given the information we have currently. However, given the current volatility in the financial markets, we cannot be certain that we will not experience such losses in the future.

Exploration and Production

The following table provides information about our financial instruments that are sensitive to changes in commodity prices and that are used to hedge prices for gas production. The table presents the notional amount in Bcf, the weighted average contract prices and the fair value by expected maturity dates. At December 31, 2008, the fair value of our financial instruments related to natural gas production and gas-in-storage was a $415.3 million asset and a $5.6 million asset, respectively.

	Weighted Average	Weighted Average	Weighted Average	Weighted Average	Fair value at

	Volume	Price to be Swapped ($/MMBtu)	Floor Price ($/MMBtu)	Ceiling Price ($/MMBtu)	Basis Differential ($/MMBtu)	December 31, 2008 ($ in millions)
Natural Gas (Bcf):						
Fixed Price Swaps:						
2009[1]	77.3	8.33				172.3
2010	36.0	9.04				65.8
Costless Collars:						
2009	59.0		8.71	11.69		160.0
2010	14.0		8.29	10.57		21.1
Basis Swaps:						
2009	50.0				(0.51)	0.1
2010	32.0				(0.30)	1.4
2011	7.2				(0.28)	0.2

(1)

Includes fixed-price swaps for 1.3 Bcf relating to future sales from our underground storage facility that have a fair value asset of $5.6 million.

At December 31, 2008, we had outstanding fixed-price basis differential swaps on 50.0 Bcf of 2009, 32.0 Bcf of 2010 and 7.2 Bcf of 2011 gas production that did not qualify for hedge accounting treatment. Changes in the fair value of derivatives that do not qualify as cash flow hedges are recorded in gas and oil sales. For the year ended December 31, 2008, we recorded an unrealized gain of $2.5 million related to the differential swaps that did not qualify for hedge accounting treatment and a loss of $7.0 million gain related to the change in estimated ineffectiveness of our cash flow hedges. Typically, our hedge ineffectiveness results from changes at the end of a reporting period in the price differentials between the index price of the derivative contract, which is primarily a NYMEX price, and the index price for the point of sale for the cash flow that is being hedged.

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At December 31, 2007, we had outstanding natural gas price swaps on total notional volumes of 55.7 Bcf in 2008 and 56.0 Bcf in 2009 for which we will receive fixed prices ranging from $7.29 to $9.98 per MMBtu. At December 31, 2007, we had outstanding fixed price basis differential swaps on 8.0 Bcf of 2008 gas production that qualified for hedge treatment and outstanding fixed price basis differential swaps on 66.8 Bcf of 2008 and 2009 gas production that did not qualify for hedge treatment.

At December 31, 2007, we had collars in place on notional volumes of 48.0 Bcf in 2008 and 23.0 Bcf in 2009. The 48.0 Bcf in 2008 had an average floor and ceiling price of $7.92 and $11.60 per MMBtu, respectively. The 23.0 Bcf in 2009 had an average floor and ceiling price of $8.09 and $10.91 per MMBtu, respectively.

Subsequent to December 31, 2008 and prior to February 23, 2009, we have basis protected an additional 9.8 Bcf of 2009, 7.3 Bcf of 2010, and 1.8 Bcf of 2011 gas production with an average differential price of $0.48 below NYMEX spot rates for our respective basis locations.

Midstream Services

At December 31, 2008, our Midstream Services segment had outstanding fair value hedges in place on 0.7 Bcf and 0.2 Bcf of gas for 2009 and 2010, respectively. These hedges are a mixture of fixed-price swap purchases and sales relating to our gas marketing activities. These hedges have contract months from January 2009 through December 2010 and have a net fair value asset of $0.5 million as of December 31, 2008.

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ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

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Management's Report on Internal Control Over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rule 13a-15(f) under the Exchange Act. We have performed an evaluation under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of our internal control over financial reporting. Our management assessed the effectiveness of our internal control over financial reporting as of December 31, 2008. Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies and procedures may deteriorate.

Our management used the criteria set forth in *Internal Control - Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) to perform its assessment. Based on this assessment, our management, including our Chief Executive Officer and our Chief Financial Officer, concluded, that as of December 31, 2008, our internal control over financial reporting was effective based on those criteria.

The effectiveness of our internal control over financial reporting as of December 31, 2008 has been audited by

PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report below.

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholders of Southwestern Energy Company:

In our opinion, the consolidated financial statements listed in the accompanying index present fairly, in all material respects, the financial position of Southwestern Energy Company and its subsidiaries at December 31, 2008 and 2007, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2008 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2008, based on criteria established in Internal Control - Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in Management s Report on Internal Control Over Financial Reporting appearing under Item 8. Our responsibility is to express opinions on these financial statements and on the Company's internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

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

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

/s/ PricewaterhouseCoopers LLP

PricewaterhouseCoopers LLP

Tulsa, Oklahoma

February 26, 2009

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STATEMENTS OF OPERATIONS

Southwestern Energy Company and Subsidiaries

	For the years ended December 31,		
	2008	2007	2006
	(in thousands, except share/per share amounts)		
Operating Revenues:			

Gas sales	**$ 1,490,646**	$ 870,047	$ 572,354
Gas marketing	**729,671**	316,912	136,698
Oil sales	**41,240**	42,434	40,742
Gas gathering	**41,748**	11,627	1,553
Transportation and other	**8,247**	14,111	11,765
	2,311,552	1,255,131	763,112
Operating Costs and Expenses:			
Gas purchases midstream services	**710,129**	306,336	128,387
Gas purchases gas distribution	**61,439**	85,445	79,363
Operating expenses	**107,577**	85,826	66,579
General and administrative expenses	**101,959**	80,269	66,112
Depreciation, depletion and amortization	**414,408**	293,914	151,290
Taxes, other than income taxes	**29,272**	21,875	25,109
	1,424,784	873,665	516,840
Operating Income	**886,768**	381,466	246,272
Interest Expense:			
Interest on debt	**61,152**	36,191	11,099
Other interest charges	**2,284**	1,474	1,402
Interest capitalized	**(34,532)**	(13,792)	(11,822)
	28,904	23,873	679
Other Income (Loss)	**4,404**	(219)	17,079
Gain on Sale of Utility Assets	**57,264**		
Income Before Income Taxes and Minority Interest	**919,532**	357,374	262,672
Minority Interest in Partnership	**(587)**	(345)	(637)
Income Before Income Taxes	**918,945**	357,029	262,035
Provision for Income Taxes:			
Current	**122,000**		
Deferred	**228,999**	135,855	99,399
	350,999	135,855	99,399
Net Income	**$ 567,946**	$ 221,174	$ 162,636
Earnings Per Share: [(1)]			
Basic	**$ 1.66**	$ 0.65	$ 0.49
Diluted	**$ 1.64**	$ 0.64	$ 0.47
Weighted Average Common Shares Outstanding: [(1)]			
Basic	**341,621,814**	338,953,446	334,606,282
Effect of:			
Stock options	**4,237,263**	8,024,198	6,953,402

Restricted stock awards	**386,861**	465,016	1,015,816
Diluted	**346,245,938**	347,442,660	342,575,500

(1) 2007 and 2006 restated to reflect the two-for-one stock split effected on March 25, 2008.

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

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BALANCE SHEETS

Southwestern Energy Company and Subsidiaries

	December 31,	
	2008	2007
ASSETS	(in thousands)	
Current Assets		
Cash and cash equivalents	$ **196,277**	$ 727
Accounts receivable	**254,557**	177,680
Inventories, at average cost	**50,377**	33,034
Hedging asset FAS 133	**343,320**	64,472
Current assets held for sale (see Note 2)		58,877
Other	**44,734**	28,551
Total current assets	**889,265**	363,341
Property, Plant and Equipment, at cost		
Gas and oil properties, using the full cost method, including $540.6 million in 2008 and $372.4 million in 2007 excluded from amortization	**4,836,077**	4,020,448
Gathering systems	**341,474**	158,604
Gas in underground storage	**13,349**	13,349
Other	**138,014**	85,983

	5,328,914	4,278,384
Less: Accumulated depreciation, depletion and amortization	**1,615,307**	1,200,754
	3,713,607	3,077,630
Assets Held For Sale (see Note 2)		143,234
Other Assets	**157,286**	38,511
	$ 4,760,158	$ 3,622,716
LIABILITIES AND STOCKHOLDERS EQUITY		
Current Liabilities		
Short-term debt	**$ 61,200**	$ 1,200
Accounts payable	**464,145**	313,070
Taxes payable	**31,951**	5,087
Interest payable	**20,857**	2,213
Advances from partners	**70,603**	32,005
Hedging liability FAS 133	**10,899**	8,598
Current deferred income taxes	**122,448**	20,909
Current liabilities associated with assets held for sale (see Note 2)		39,118
Other	**10,758**	8,695
Total current liabilities	**792,861**	430,895
Long-Term Debt	**674,200**	977,600
Other Liabilities		
Deferred income taxes	**721,707**	479,196
Long-term hedging liability	**5,934**	15,186
Pension and other postretirement liabilities	**15,436**	14,618
Liabilities associated with assets held for sale (see Note 2)		15,417
Other	**32,057**	32,734
	775,134	557,151
Commitments and Contingencies		
Minority Interest in Partnership	**10,133**	10,570
Stockholders Equity		
Common stock, $0.01 par value; authorized 540,000,000 shares, issued 343,624,956		
shares in 2008 and 341,581,672 in 2007(1)	**3,436**	3,416
Additional paid-in capital(1)	**811,492**	752,369
Retained earnings	**1,449,977**	882,031
Accumulated other comprehensive income	**247,665**	13,348
Common stock in treasury, 225,050 shares in 2008 and 222,774 in 2007(1)	**(4,740)**	(4,664)
	2,507,830	1,646,500
	$ 4,760,158	$ 3,622,716

(1) 2007 restated to reflect the two-for-one stock split effected on March 25, 2008.

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

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STATEMENTS OF CASH FLOWS

Southwestern Energy Company and Subsidiaries

	For the years ended December 31,		
	2008	2007	2006
		(in thousands)	
Cash Flows From Operating Activities			
Net Income	**$ 567,946**	$ 221,174	$ 162,636
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, depletion and amortization	**416,151**	295,332	152,519
Deferred income taxes	**228,999**	135,855	99,399
Gain on sale of utility assets	**(57,264)**		
Unrealized loss (gain) on derivatives	**4,644**	(7,103)	5,579
Stock-based compensation expense	**7,952**	6,377	5,164
Gain on sale of investment in partnership and other property	**(497)**		(10,285)
Minority interest in partnership	**(437)**	(465)	(579)
Equity in income of NOARK partnership			(925)

Change in assets and liabilities:			
Accounts receivable	**(60,117)**	(76,136)	(2,422)
Inventories	**(39,475)**	(10,800)	(12,975)
Accounts payable	**72,894**	61,284	20,742
Taxes payable	**20,855**	(3,454)	1,568
Interest payable	**18,522**	198	(808)
Advances from partners and customer deposits	**38,418**	7,615	24,317
Excess tax benefit for stock-based compensation	**(43,107)**		(14,609)
Other assets and liabilities	**(14,675)**	(7,142)	616
Net cash provided by operating activities	**1,160,809**	622,735	429,937

Cash Flows From Investing Activities	nbsp;		
Net cash used in investing activities	(8,741,030)	(7,496,801)	(14,059,651)
Financing Activities:			
Proceeds from issuance of common stock and warrants, net	26,725,130	14,071,694	9,564,640
Proceeds from issuance of convertible promissory note			5,000,000
Proceeds from exercise of warrants	1,316,503	4,083,300	16,249
Proceeds from exercise of options	522,000	23,500	
Net cash provided by financing activities	28,563,633	18,178,494	14,580,889
Net increase (decrease) in cash and cash equivalents	6,880,820	806,019	(4,619,128)
Cash and cash equivalents beginning of period	2,215,958	1,409,939	6,029,067
	$ 9,096,778	$ 2,215,958	$ 1,409,939

Cash and cash equivalents end of period						
Non-cash investing and financing activities:						
Exercise of liability classified warrants for common stock	$	18,537	$	569,384	$	16,875
Conversion of note to common stock	$		$		$	5,000,000

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

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CATALYST PHARMACEUTICAL PARTNERS, INC.

NOTES TO FINANCIAL STATEMENTS

1. Organization and Description of Business

Catalyst Pharmaceutical Partners, Inc. (the Company) is a development-stage biopharmaceutical company focused on the development and commercialization of prescription drugs targeting rare (orphan) neurological diseases and disorders, including Lambert-Eaton Myasthenic Syndrome (LEMS) and infantile spasms. The Company was incorporated in Delaware in July 2006. It is the successor by merger to Catalyst Pharmaceutical Partners, Inc., a Florida corporation, which commenced operations in January 2002.

Since inception, the Company has devoted substantially all of its efforts to business planning, research and development, recruiting management and technical staff, acquiring operating assets and raising capital. The Company s primary focus is on the development and commercialization of its drug candidates. The Company has incurred operating losses in each period from inception through December 31, 2014. The Company has been able to fund its cash needs to date through several public and private offerings of its common stock and warrants, through government grants, and through an investment by a strategic purchaser. See Note 11.

Capital Resources

On January 31, 2014, the Company filed a Shelf Registration Statement on Form S-3 (the 2014 Shelf Registration Statement) with the U.S. Securities and Exchange Commission (SEC) to sell up to $100 million of common stock. This registration statement (file No. 333-193699) was declared effective by the SEC on March 19, 2014. On April 3, 2014, the Company sold 13,023,750 shares of its common stock in an underwritten public offering under the 2014 Shelf Registration Statement, raising net proceeds of approximately $26.7 million. Subsequent to year end, on February 4, 2015, the Company sold 11,500,000 shares of its common stock in an underwritten public offering under the 2014 Shelf Registration Statement, raising net proceeds of approximately $34.7 million. (See Note 11). While there can be no assurance, based on currently available information, the Company estimates that it currently has sufficient working capital to support its operations through the end of 2016. The Company will require additional capital to support its operations in periods after 2016.

The Company may raise required funds in the future through public or private equity offerings, debt financings, corporate collaborations, governmental research grants or other means. The Company may also seek to raise new capital to fund additional product development efforts, even if it has sufficient funds for its planned operations. Any sale by the Company of additional equity or convertible debt securities could result in dilution to the Company s current stockholders. There can be no assurance that any such required additional funding will be available to the Company at all or available on terms acceptable to the Company. Further, to the extent that the Company raises additional funds through collaborative arrangements, it may be necessary to relinquish some rights to the Company s drug candidates or grant sublicenses on terms that are not favorable to the Company. If the Company is not able to secure additional funding when needed, the Company may have to delay, reduce the scope of, or eliminate one or more research and development programs, which could have an adverse effect on the Company s business.

2. Basis of Presentation and Significant Accounting Policies

a. **USE OF ESTIMATES.** The preparation of financial statements in conformity with U.S. generally accepted accounting principles requires management to make estimates and assumptions that affect the amounts reported in the financial statements and accompanying notes. Actual results could differ from those estimates.

b. **CASH AND CASH EQUIVALENTS.** The Company considers all highly liquid instruments, purchased with an original maturity of three months or less to be cash equivalents. Cash equivalents consist mainly of money market funds. The Company has substantially all of its cash and cash equivalents deposited with one financial institution.

2. Basis of Presentation and Significant Accounting Policies (continued)

c. **CERTIFICATES OF DEPOSIT.** The certificates of deposit were issued by a banking institution and are recorded at cost plus accrued interest. The original maturity was greater than three months but did not exceed one year. Interest income is recorded in the statement of operations as it is earned. Carrying value at December 31, 2014 and 2013 approximates fair value.

d. **SHORT-TERM INVESTMENTS.** The Company invests in short-term investments in high credit-quality funds in order to obtain higher yields on its cash available for investments. As of December 31, 2014 and 2013 short-term investments consisted of a short-term bond fund. Such investments are not insured by the Federal Deposit Insurance Corporation. Short-term investments at December 31, 2014 and 2013 were considered trading securities. Trading securities are recorded at fair value based on the closing market price of the security. For trading securities, the Company recognizes realized gains and losses and unrealized gains and losses to earnings. Unrealized and realized losses on trading securities for the years ended December 31, 2014 and 2013 were nominal and are included in other income, net in the accompanying statements of operations.

e. **PREPAID EXPENSES AND OTHER CURRENT ASSETS.** Prepaid expenses and other current assets consist primarily of insurance recoverable, prepaid research fees, prepaid insurance and prepaid subscription fees. Insurance recoverable relates to the securities class action lawsuit proposed settlement to be paid by the Company s insurance carrier. Prepaid research fees consist of advances for the Company s product development activities, including drug manufacturing, contracts for pre-clinical studies, clinical trials and studies, regulatory affairs and consulting. Such advances are recorded as expense as the related goods are received or the related services are performed.

f. **PROPERTY AND EQUIPMENT.** Property and equipment are recorded at cost. Depreciation is calculated to amortize the depreciable assets over their useful lives using the straight-line method and commences when the asset is placed in service. Useful lives generally range from three years for computer equipment to three to six years for furniture and equipment. Expenditures for repairs and maintenance are charged to expenses as incurred.

g. **OPERATING LEASES.** The Company recognizes lease expense on a straight-line basis over the initial lease term. For leases that contain rent holidays, escalation clauses or tenant improvement allowances, the Company recognizes rent expense on a straight-line basis and records the difference between the rent expense and rental amount payable as deferred rent. As of December 31, 2014 and 2013, the Company had $19,997 and $21,877, respectively, of deferred rent in accrued expenses and other liabilities.

h. **FAIR VALUE OF FINANCIAL INSTRUMENTS.** The Company s financial instruments consist of cash and cash equivalents, certificates of deposit, short-term investments, accounts payable and accrued expenses and other liabilities, and warrants liability. At December 31, 2014 and 2013, the fair value of these instruments approximated their carrying value.

i. **FAIR VALUE MEASUREMENTS.** Current Financial Accounting Standards Board (FASB) fair value guidance emphasizes that fair value is a market-based measurement, not an entity-specific measurement. Therefore, a fair value measurement should be determined based on the assumptions that market participants would use in pricing the asset or liability. As a basis for considering market participant assumptions in fair value measurements, current FASB guidance establishes a fair value hierarchy that distinguishes between market participant assumptions based on market data obtained from sources independent of the reporting entity (observable inputs that are classified within Levels 1 and 2 of the hierarchy) and the reporting entity s own assumptions that it believes market participants would use in pricing assets or liabilities (unobservable inputs classified within Level 3 of the hierarchy).

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2. Basis of Presentation and Significant Accounting Policies (continued)

Level 1 inputs utilize quoted prices (unadjusted) in active markets for identical assets or liabilities that the Company has the ability to access at the measurement date. Level 2 inputs are inputs other than quoted prices included in Level 1 that are observable for the asset or liability, either directly or indirectly. Level 2 inputs may include quoted prices for similar assets and liabilities in active markets, as well as inputs that are observable for the asset or liability (other than quoted prices), such as interest rates, foreign exchange rates, and yield curves that are observable at commonly quoted intervals. Level 3 inputs are unobservable inputs for the asset or liability, which are typically based on an entity s own assumptions, as there is little, if any, related market activity. In instances where the determination of the fair value measurement is based on inputs from different levels of the fair value hierarchy, the level in the fair value hierarchy within which the entire fair value measurement falls is based on the lowest level input that is significant to the fair value measurement in its entirety. The Company s assessment of the significance of a particular input to the fair value measurement in its entirety requires judgment, and considers factors specific to the asset or liability.

		Fair Value Measurements at Reporting Date Using		
	Balances as of December 31, 2014	Quoted Prices in Active Markets for Identical Assets/Liabilities (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Money market funds	$ 7,053,310	$ 7,053,310	$	$
Certificates of deposit	$ 3,715,383	$	$ 3,715,383	$
Short-term investments	$ 26,462,962	$ 26,462,962	$	$
Warrants liability	$ 2,794,891	$	$	$ 2,794,891

		Fair Value Measurements at Reporting Date Using		
	Balances as of December 31, 2013	Quoted Prices in Active Markets for Identical Assets/Liabilities (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Money market funds	$ 25,693	$ 25,693	$	$
Certificates of deposit	$ 4,011,576	$	$ 4,011,576	$

Short-term investments	$ 17,483,062	$ 17,483,062	$	$
Warrants liability	$ 1,819,562	$	$	$ 1,819,562

j. **WARRANTS LIABILITY.** In October 2011, the Company issued 1,523,370 warrants (the 2011 warrants) to purchase shares of the Company s common stock in connection with a registered direct offering under the 2010 Shelf Registration Statement. The Company accounted for these warrants as a liability measured at fair value due to a provision included in the warrants agreement that provides the warrants holders with an option to require the Company (or its successor) to purchase their warrants for cash in an amount equal to their Black-Scholes Option Pricing Model (the Black-Scholes Model) value, in the event that certain fundamental transactions, as defined, occur. The fair value of the warrants liability is estimated using the Black-Scholes Model which requires inputs such as the expected term of the warrants, share price volatility and risk-free interest rate. These assumptions are reviewed on a quarterly basis and changes in the estimated fair value of the outstanding warrants are recognized each reporting period in the Change in fair value of warrants liability line in the statements of operations. As of December 31, 2014 and 2013, 1,242,174 and 1,254,870, respectively, of the 2011 warrants remained outstanding.

k. **RESEARCH AND DEVELOPMENT.** Costs incurred in connection with research and development activities are expensed as incurred. These costs consist of direct and indirect costs associated with specific projects as well as fees paid to various entities that perform research related services for the Company.

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2. Basis of Presentation and Significant Accounting Policies (continued)

l. **STOCK-BASED COMPENSATION.** The Company recognizes expense in the statement of operations for the fair value of all stock-based payments to employees, directors, scientific advisors and consultants, including grants of stock options and other share-based awards. For stock options, the Company uses the Black-Scholes option valuation model, the single-option award approach and the straight-line attribution method. Using this approach, compensation cost is amortized on a straight-line basis over the vesting period of each respective stock option, generally three to seven years. The Company estimates forfeitures and adjusts this estimate periodically based on actual forfeitures.

For the years ended December 31, 2014, 2013 and 2012, the Company recorded stock-based compensation expense as follows:

	2014	2013	2012
Research and development	$ 133,862	$ 84,728	$ 100,221
General and administrative	644,107	91,127	239,818
Total stock-based compensation	$ 777,969	$ 175,855	$ 340,039

m. **CONCENTRATION OF CREDIT RISK.** The financial instruments that potentially subject the Company to concentration of credit risk are cash equivalents (i.e. money market funds), short-term investments and certificates of deposit. The Company places its cash equivalents with high-credit quality financial institutions. These amounts at times may exceed federally insured limits. The Company has not experienced any credit losses in these accounts.

n. **INCOME TAXES.** The Company utilizes the asset and liability method of accounting for income taxes. Under this method, deferred tax assets and liabilities are determined based on differences between financial reporting and tax bases of assets and liabilities and are measured using enacted tax rates and laws that will be in effect when the differences are expected to reverse. A valuation allowance is provided when it is more likely than not that some portion or all of a deferred tax asset will not be realized.

The Company recognizes the financial statement benefit of a tax position only after determining that the relevant tax authority would more likely than not sustain the position following an audit. For tax positions meeting the more-likely-than-not threshold, the amount recognized in the financial statements is the largest benefit that has a greater than 50 percent likelihood of being realized upon ultimate settlement with the relevant tax authority.

The Company is subject to income taxes in the U.S. federal jurisdiction and various state jurisdictions. Tax regulations within each jurisdiction are subject to the interpretation of the related tax laws and regulations and require significant judgment to apply. The Company is not subject to U.S. federal, state and local tax examinations by tax authorities for years before 2010. If the Company were to subsequently record an unrecognized tax benefit, associated penalties and tax related interest expense would be reported as a component of income tax expense.

o. COMPREHENSIVE INCOME (LOSS). U.S. generally accepted accounting principles require that all components of comprehensive income (loss) be reported in the financial statements in the period in which they are recognized. Comprehensive income (loss) is net income (loss), plus certain other items that are recorded directly into stockholders equity. For all periods presented, the Company s net loss equals comprehensive loss, since the Company has no items which are considered other comprehensive income (loss).

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2. Basis of Presentation and Significant Accounting Policies (continued)

p. **NET INCOME (LOSS) PER SHARE.** Basic income (loss) per share is computed by dividing net income (loss) for the period by the weighted average number of common shares outstanding during the period. Diluted income (loss) per share is computed by dividing net income (loss) for the period by the weighted average number of common shares outstanding during the period, plus the dilutive effect of common stock equivalents, such as convertible preferred stock, stock options and restricted stock units. For all periods presented, all common stock equivalents were excluded because their inclusion would have been anti-dilutive. The potential shares, which are excluded from the determination of basic and diluted net loss per share as their effect is anti-dilutive, are as follows, for the years ended December 31, 2014, 2013 and 2012:

	2014	2013	2012
Options to purchase common stock	3,884,610	3,428,906	3,650,535
Warrants to purchase common stock	3,585,924	4,848,620	8,710,870
Unvested restricted stock	80,000		
Potential equivalent common stock excluded	7,550,534	8,277,526	12,361,405

Potentially dilutive options to purchase common stock as of December 31, 2014 have exercise prices ranging from $0.47 to $3.12. Potentially dilutive options to purchase common stock as of December 31, 2013 and 2012 have exercise prices ranging from $0.47 to $6.00. Potentially dilutive warrants to purchase common stock as of December 31, 2014, 2013 and 2012 have exercise prices ranging from $1.04 to $2.08.

q. **SEGMENT INFORMATION.** Management has determined that the Company operates in one reportable segment, which is the development and commercialization of pharmaceutical products.

r. **RECLASSIFICATIONS.** Certain prior year amounts in the financial statements have been reclassified to conform to the current year presentation.

s. **RECENTLY ISSUED ACCOUNTING STANDARDS.** In June 2014, the FASB issued ASU No. 2014-10, Development Stage Entities (Topic 915): *Elimination of Certain Financial Reporting Requirements, Including an Amendment to Variable Interest Entities Guidance in Topic 810, Consolidation*. The amendments in this ASU include: i) eliminating the requirement to present inception-to-date information on the statements of income, cash flows, and shareholders equity, ii) eliminating the need to label the financial statements as those of a development stage entity, iii) eliminating the need to disclose a description of the development stage activities in which the entity is engaged, and iv) eliminating the requirement to disclose in the first year in which the entity is no longer a development stage entity that in prior years it had been in the development stage. The amendments in ASU No. 2014-10 are effective for public companies for annual and interim reporting periods beginning after December 15, 2014. Early adoption is permitted. The Company has early adopted ASU No. 2014-10, beginning with the interim period ended June 30, 2014.

In August 2014, the FASB issued ASU No. 2014-15, Presentation of Financial Statements Going Concern (Subtopic 205-40): *Disclosure of Uncertainties about an Entity s Ability to Continue as a Going Concern.* The amendments in this ASU, require management to assess a company s ability to continue as a going concern and to provide related disclosures in certain circumstances. The guidance will be effective for the annual period ending after December 15, 2016 and subsequent interim and annual periods thereafter. The Company is currently evaluating the impact of this accounting standard update on its financial statements.

3. Warrants Liability, at Fair Value

The Company allocated approximately $1.3 million of proceeds from its October 2011 registered direct offering to the fair value of common stock purchase warrants issued in connection with the offering that are classified as a liability (the 2011 warrants). The 2011 warrants are classified as a liability because of provisions in such warrants that allow for the net cash settlement of such warrants in the event of certain fundamental transactions (as defined in the warrant agreement). The valuation of the 2011 warrants is determined using the Black-Scholes Model. This model uses inputs such as the underlying price of the shares issued when the warrant is exercised, volatility, risk free interest rate and expected life of the instrument. The Company has determined that the 2011 warrants liability should be classified within Level 3 of the fair value hierarchy by evaluating each input for the Black-Scholes Model against the fair value hierarchy criteria and using the lowest level of input as the basis for the fair value classification. There are six inputs: closing price of the Company s common stock on the day of evaluation; the exercise price of the warrants; the remaining term of the warrants; the volatility of the Company s common stock; annual rate of dividends; and the risk free rate of return. Of those inputs, the exercise price of the warrants and the remaining term are readily observable in the warrants agreement. The annual rate of dividends is based on the Company s historical practice of not granting dividends. The closing price of the Company s common stock would fall under Level 1 of the fair value hierarchy as it is a quoted price in an active market. The risk free rate of return is a Level 2 input, while the historical volatility is a Level 3 input in accordance with the fair value accounting guidance. Since the lowest level input is a Level 3, the Company determined the 2011 warrants liability is most appropriately classified within Level 3 of the fair value hierarchy. This liability is subject to fair value mark-to-market adjustment each reporting period. The calculated value of the 2011 warrants liability was determined using the Black-Scholes option-pricing model with the following assumptions:

	December 31, 2014	December 31, 2013
Risk free interest rate	0.81%	0.94%
Expected term	2.34 years	3.34 years
Expected volatility	112%	108%
Expected dividend yield	0%	0%
Expected forfeiture rate	0%	0%

The following table rolls forward the fair value of the Company s warrants liability activity for the years ended December 31, 2014, 2013 and 2012:

	2014	2013	2012
Fair value, beginning of period	$ 1,819,562	$ 498,587	$ 1,645,240
Issuance of warrants			
Exercise of warrants	(18,537)	(569,384)	(16,875)
Change in fair value	993,866	1,890,359	(1,129,778)
Fair value, end of period	$ 2,794,891	$ 1,819,562	$ 498,587

During 2014, 12,696 of the 2011 warrants were exercised, with proceeds to the Company of $16,504. During 2013, 256,000 of the 2011 warrants were exercised, with proceeds to the Company of $332,800. During 2012, 12,500 of the 2011 warrants were exercised with proceeds to the Company of $16,249. The Company recognizes the change in the fair value of the warrants liability as a non-operating income or loss in the accompanying statements of operations.

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4. Prepaid Expenses and Other Current Assets

Prepaid expenses and other current assets consist of the following as of December 31:

	2014	2013
Insurance recoverable (see Note 7)	$ 3,500,000	$
Prepaid research fees	571,428	1,334,149
Prepaid insurance	385,496	219,651
Prepaid subscriptions fees	30,495	24,643
Prepaid offering costs	20,029	
Prepaid rent	10,870	7,848
Other	34,380	23,151
Total prepaid expenses	$ 4,552,698	$ 1,609,442

5. Property and Equipment

Property and equipment, net consists of the following as of December 31:

	2014	2013
Computer equipment	$ 95,754	$ 81,551
Furniture and equipment	88,816	51,523
	184,570	133,074
Less: Accumulated depreciation	(113,193)	(92,446)
Total property and equipment, net	$ 71,377	$ 40,628

Depreciation expense was $26,574, $22,483 and $10,889, respectively, for the years ended December 31, 2014, 2013 and 2012.

6. Accrued Expenses and Other Liabilities

Accrued expenses and other liabilities consist of the following as of December 31:

	2014	2013
Accrued settlement liability (see Note 7)	$ 3,500,000	$
Accrued pre-clinical and clinical trial expenses	333,928	1,083,749
Accrued professional fees	43,973	117,240
Accrued compensation and benefits	31,956	14,539
Accrued license fees	115,000	65,000

Deferred rent	4,158	2,746
Other	11,801	5,546
Current accrued expenses and other liabilities	4,040,816	1,288,820
Deferred rent non-current	15,839	19,131
Non-current accrued expenses and other liabilities	15,839	19,131
Total accrued expenses and other liabilities	$ 4,056,655	$ 1,307,951

The accrued settlement liability of $3,500,000 as of December 31, 2014 is related to the securities class action lawsuit proposed settlement, as disclosed with more particularity in Note 7. The proposed settlement amount is expected to be paid for and covered by the Company s insurance carrier; therefore, there is a corresponding insurance recoverable recorded in Prepaid Expenses and Other Current Assets in the accompanying balance sheet as of December 31, 2014.

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7. Commitments and Contingencies

The Company has contracted with drug manufacturers and other vendors, including clinical research organizations (CRO) overseeing the clinical trials of the Company s drug candidates, to assist in the execution of the Company s pre-clinical and clinical trials, analysis, and the preparation of material necessary for the future submission of new drug applications (NDA s) with the U.S. Food and Drug Administration (FDA). The contracts are cancelable at any time, but obligate the Company to reimburse the providers for any time or costs incurred through the date of termination.

The Company has executed a noncancellable operating lease agreement for its corporate office. The lease has free and escalating rent payment provisions. The Company recognizes rent expense under such lease on a straight-line basis over the term of the lease. As of December 31, 2014, future minimum lease payments under the operating lease agreement are as follows:

2015	$ 103,902
2016	107,010
2017	100,076
	$ 310,988

During June 2011, in connection with the renewal of the corporate office lease, the Company entered into the first amendment to the lease. The amendment extends the original lease term for five years and relocated the Company into another space within the same building. During February 2014, the Company entered into the second amendment of the lease for an additional contiguous space under substantially the same terms. The corporate office lease is cancellable upon the payment of an early termination penalty during 2015. The lease provides for fixed increases in minimum annual rent payments, as well as rent free periods. The total amount of rental payments due over the lease term is being charged to rent expense on the straight-line method over the term of the lease. The differences between rent expense recorded and the amount paid is credited or charged to accrued expenses and other liabilities in the accompanying balance sheets. Rent expense was $90,163, $69,930 and $65,310, respectively, for the years ended December 31, 2014, 2013 and 2012. The Company s office lease expires in November 2017.

Securities Class Action Lawsuit

In October 2013 and November 2013, three securities class action lawsuits were filed against the Company and certain of its executive officers and directors seeking unspecified damages in the U.S. District Court for the Southern District of Florida (the Court). These complaints, which were substantially identical, purported to state a claim for violation of federal securities laws on behalf of a class of those who purchased the Company s common stock between October 31, 2012 and October 18, 2013. Two of the cases were voluntarily dismissed by the plaintiffs and the Court granted the Company s motion to dismiss on the third case on January 3, 2014. However, the Court granted leave to the plaintiffs to file an amended complaint within 20 days.

On January 23, 2014, the plaintiffs filed an amended complaint against the Company and one of its executive officers seeking unspecified damages. The amended complaint purports to state a claim for alleged misrepresentations regarding the development of Firdapse on behalf of a class of those who purchased shares of the Company s common stock between August 27, 2013 and October 18, 2013. In February 2014, the Company filed a motion to dismiss the amended complaint, which was granted in part and denied in part by the Court. Subsequently, on September 29, 2014, the Court certified a class consisting of all persons or entities that purchased shares of the Company s common stock during the period from August 27, 2013, through October 18, 2013 (the Class Period), and who did not sell such securities prior to October 18, 2013 (excluding: defendants; any entities affiliated with the Company, the present and former officers and directors of the Company or any subsidiary or affiliate thereof; members of such excluded persons immediate families and their legal representatives, heirs, successors or assigns; and any entity in which any excluded person has or had a controlling interest).

7. Commitments and Contingencies (continued)

Following a mediation in mid-October conducted by an independent mediator, the Company entered into a memorandum of understanding (MOU) with the lead plaintiffs in the class action lawsuit to settle the lawsuit. The settlement was then reduced to a formal stipulation of settlement between the parties to the lawsuit, which was filed with the Court on November 21, 2014. The settlement was preliminarily approved by the Court in December 3, 2014, and a final hearing to determine the fairness of the settlement has been scheduled for March 16, 2015.

In connection with the settlement, the Company will pay $3.5 million in return for a dismissal and release of all claims against the defendants. The settlement amount has been placed in escrow by the Company s insurance carrier, subject to final Court approval of the settlement. Under the proposed settlement, the defendants, and various of their related persons and entities, will receive a full release of all claims that were or could have been brought in the action, as well as all claims that arise out of, are based upon, or relate to the allegations, transactions, facts, representations, omissions or other matters involved in the action related in any way to the purchase or acquisition of the Company s securities by class members during the class period.

The proposed settlement contains no admission of any liability or wrongdoing on the part of the defendants, each of whom continues to deny all of the allegations against each of them and believes that the claims are without merit. Because the full amount of the proposed settlement payment is expected to be paid by the Company s insurance carrier, the settlement is not expected to have a material adverse effect on the Company s financial position or results of operations. There can be no assurance that the settlement will be approved by the Court.

Obligations under capital leases are not significant.

For commitments related to the Company s license agreements with BioMarin (defined below) and Northwestern (defined below), see Note 8.

8. Agreements

a. **LICENSE AGREEMENT WITH BROOKHAVEN.** The Company had a license agreement with Brookhaven Science Associates, LLC, as operator of Brookhaven National Laboratory under contract with the United States Department of Energy (Brookhaven), whereby the Company had obtained an exclusive license for several patents and patent applications in the U.S. and outside the U.S. relating to the use of vigabatrin as a treatment for cocaine and other addictions and obsessive-compulsive disorders. This license agreement ran concurrently with the term of the last to expire of the licensed patents, the last of which currently expires in 2023. The Company paid a fee to obtain the license in the amount of $50,000. Under the license agreement, the Company agreed to pay Brookhaven certain milestones and to reimburse them for certain patent related expenses.

On November 8, 2013, effective October 1, 2013, the Company and Brookhaven entered into a termination agreement cancelling the license agreement. As part of that agreement, the Company and Brookhaven entered into mutual releases, including a release from any further obligation for the Company to reimburse Brookhaven for any of Brookhaven s patent related expenses.

b. **LICENSE AGREEMENT WITH NORTHWESTERN UNIVERSITY.** On August 27, 2009, the Company entered into a license agreement with Northwestern University (Northwestern), under which it acquired worldwide rights to commercialize new GABA aminotransferase inhibitors and derivatives of vigabatrin that have been discovered by Northwestern. Under the terms of the license agreement, Northwestern granted the Company an exclusive worldwide license to certain composition of matter patents related to the new class of inhibitors and a patent application relating to derivatives of vigabatrin. The Company has identified and designated the lead compound under this license as CPP-115.

8. Agreements (continued)

Under the license agreement with Northwestern, the Company is responsible for continued research and development of any resulting product candidates. As of December 31, 2014, the Company had paid Northwestern $251,590 in connection with the license and had accrued license fees of $115,000 and $65,000 as of December 31, 2014 and 2013, respectively, in the accompanying balance sheets for expenses, maintenance fees and milestones. In addition, the Company is obligated to pay certain milestone payments in future years relating to clinical development activities with respect to CPP-115, and royalties on any products resulting from the license agreement. The next milestone payment of $150,000 is due on the earlier of successful completion of the first Phase 2 clinical trial for CPP-115 or August 27, 2015.

c. **LICENSE AGREEMENT WITH NEW YORK UNIVERSITY AND THE FEINSTEIN INSTITUTE FOR MEDICAL RESEARCH.** On December 13, 2011, the Company entered into a license agreement with New York University (NYU) and the Feinstein Institute for Medical Research (FIMR) under which it acquired worldwide rights to commercialize GABA aminotransferase inhibitors in the treatment for Tourette Syndrome. The Company is obligated to pay certain milestone payments in future years relating to clinical development activities and royalties on any products resulting from the license agreement.

d. **LICENSE AGREEMENT WITH BIOMARIN**. On October 26, 2012, the Company entered into a strategic collaboration with BioMarin Pharmaceutical, Inc. (BioMarin) for Firdapse . The key components of the collaboration include: (i) the Company licensed the exclusive North American rights to Firdapse pursuant to a License Agreement, dated as of October 26, 2012 (the License Agreement) between the Company and BioMarin, and (ii) BioMarin made a $5,000,000 investment in the Company pursuant to the terms of a Convertible Promissory Note and Note Purchase Agreement, dated as of October 26, 2012 (the Investment Agreement). The Investment Agreement provides that the Company will use the $5 million solely for the purpose of developing Firdapse .

As part of the License Agreement, the Company took over a Phase 3 Trial previously being conducted by BioMarin and is obligated to use its diligent efforts to seek to obtain regulatory approval for and to commercialize Firdapse in the United States. The Company was obligated to use diligent efforts to complete the double-blind treatment phase of the Phase 3 Trial within 24 months of entering into the License Agreement, and BioMarin had the right to terminate the License Agreement if such treatment phase had not been completed in such 24-month period (unless the Company was using diligent effort to pursue the completion of such treatment phase and had spent at least $5 million in connection with the conduct of the Phase 3 Trial during such 24 month period, which condition has been satisfied during the third quarter of 2014.). On September 29, 2014, the Company announced positive top-line results from its Phase 3 Trial of Firdapse for the symptomatic treatment of LEMS. Both co-primary endpoints, quantitative myasthenia gravis score (QMG) and subject global impression (SGI) demonstrated statistical significance, as did a secondary endpoint for the physician s clinical global impression of improvement (CGI-I).

As part of the License Agreement, the Company agreed: (i) to pay BioMarin royalties for seven years from the first commercial sale of Firdapse equal to 7% of net sales (as defined in our license agreement) in North America for any calendar year for sales up to $100 million, and 10% of net sales in North America in any calendar year in excess of $100 million; (ii) to pay to the third-party licensor of the rights sublicensed to us royalty payments for seven years from the first commercial sale of Firdapse equal to 7% of net sales (as defined in the license agreement between BioMarin and the third-party licensor) in any calendar year; and (iii) to pay certain milestone payments that BioMarin is obligated to pay (approximately $2.6 million of which will be due upon acceptance by the FDA of a filing of an NDA for Firdapse for the treatment of LEMS, and approximately $7.2 million of which will be due on the unconditional approval by the FDA of an NDA for Firdapse for the treatment of LEMS). The Company also agreed to share in the cost of certain post-marketing studies being conducted by BioMarin, and, as of December 31, 2014, the Company had paid BioMarin $3.1 million related to expenses in connection with Firdapse studies and trials.

8. Agreements (continued)

On April 15, 2014, effective as of April 8, 2014, the Company and BioMarin entered into Amendment No. 1 to the License Agreement, amending in certain respects the License Agreement, dated October 26, 2012, between the Company and BioMarin. The amendment related to purchases of additional product by the Company from BioMarin, the sharing of data between the parties with respect to clinical trials and studies undertaken by each party and the payment terms for certain joint studies.

e. **AGREEMENTS FOR DRUG DEVELOPMENT, PRE-CLINICAL AND CLINICAL STUDIES**. The Company has entered into agreements with contract manufacturers for the manufacture of drug and study placebo for the Company s trials and studies, with contract research organizations (CRO) to conduct and monitor the Company s trials and studies and with various entities for laboratories and other testing related to the Company s trials and studies. The contractual terms of the agreements vary, but most require certain advances as well as payments based on the achievement of milestones. Further, these agreements are cancellable at any time, but obligate the Company to reimburse the providers for any time or costs incurred through the date of termination.

9. Related Party Transactions

The Company has entered into consulting agreements with one of the Company s officers and members of the Company s Scientific Advisory Board. During the years ended December 31, 2014, 2013 and 2012, the Company paid approximately $10,000, $10,000 and $42,000, respectively, in consulting fees to related parties.

The Company has an employment agreement with its Chief Executive Officer. Under this agreement, the CEO will receive an annual base salary of approximately $453,000 in 2015, and may earn bonus compensation of up to 50% of his salary based on performance. This agreement expires in November 2016.

10. Income Taxes

As of December 31, 2014 and 2013, the Company had deferred tax assets of approximately $24,895,000 and $19,387,000, respectively, of which approximately $22,898,000 and $17,685,000 represent United States federal and state net operating loss carryforwards and start-up costs. The remaining temporary differences represent non-deductible stock option and equity expense. The related deferred tax asset has a 100% valuation allowance as of December 31, 2014 and 2013, as the Company believes it is more likely than not that the deferred tax asset will not be realized. The change in valuation allowance was approximately $5,508,000, $3,796,000 and $2,151,000 in 2014, 2013 and 2012, respectively. There are no other significant temporary differences. The net operating loss carry-forwards of approximately $40,604,000 as of December 31, 2014 will expire at various dates beginning in 2025 and ending in 2034. If an ownership change, as defined under Internal Revenue Code Section 382, occurs, the use of these carry-forwards may be subject to limitation. The effective tax rate of 0% in all periods presented differs from the statutory rate of 35% due to the valuation allowance and because the Company had no taxable income.

11. Stockholders Equity

Preferred Stock

The Company has 5,000,000 shares of authorized preferred stock, $0.001 par value per share at December 31, 2014 and 2013. No shares of preferred stock were outstanding at December 31, 2014 and 2013.

Common Stock

The Company has 100,000,000 shares of authorized common stock with a par value of $0.001 per share. At December 31, 2014 and 2013, 69,119,092 and 54,132,937 shares, respectively, of common stock were issued and outstanding. Each holder of common stock is entitled to one vote of each share of common stock held of record on all matters on which stockholders generally are entitled to vote.

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11. Stockholders Equity (continued)

2010 Shelf Registration Statement

On December 3, 2010, the Company filed a Shelf Registration Statement on Form S-3 (the 2010 Shelf Registration Statement) with the SEC to sell up to $30 million of common stock and common stock purchase warrants. This registration statement (file No. 333-170945) was declared effective by the SEC on December 15, 2010. The Company has to date conducted the following sales of its securities under the 2010 Shelf Registration Statement:

(a) On March 8, 2011, the Company filed a prospectus supplement and offered for sale to institutional investors 2,259,943 shares of its common stock at a price of $1.12 per share and received gross proceeds of approximately $2.5 million, before underwriting commission and incurred expenses of approximately $300,000.

(b) On October 28, 2011, the Company filed a prospectus supplement and offered for sale to institutional investors 3,046,740 shares of its common stock together with common stock purchase warrants to purchase 1,523,370 shares of the Company s common stock at a price of $1.15 per share and corresponding warrant and received gross proceeds of approximately $3.5 million, before underwriting commission and other expenses totaling approximately $335,000. The warrants issued in this offering, which expire on April 28, 2017 and have an exercise price of $1.30 per share, have been accounted for as a liability. See Note 3.

(c) On August 28, 2012, the Company filed a prospectus supplement and offered for sale to institutional investors 4,000,000 shares of its common stock together with common stock purchase warrants to purchase 1,200,000 shares of the Company s common stock at a price of $1.50 per share and corresponding warrant and received gross proceeds of approximately $6.0 million, before underwriting commission and other expenses totaling approximately $440,000. These warrants, which will expire on August 28, 2017 and have an exercise price of $2.08 per share, have been accounted for as equity instruments, since they do not contain features (such as cash settlement or anti-dilution features) that would preclude the Company from accounting for these warrants as equity.

(d) On September 5, 2013, the Company filed a prospectus supplement and offered for sale to institutional investors 8,800,000 shares of its common stock at a price of $1.72 per share and received gross proceeds of approximately $15.1 million before underwriting commissions and incurred expenses of approximately $1,064,000.

The Company has no further availability under the 2010 Shelf Registration Statement.

2012 Form S-1 Registration Statement

On May 24, 2012, the Company sold 6,000,000 shares of its common stock together with common stock purchase warrants to purchase 6,000,000 shares of the Company s common stock, at a price of $0.80 per share and corresponding warrant. These securities were issued pursuant to a Form S-1 registration statement that became effective on May 23, 2012 (file no. 333-180617). The Company received gross proceeds of approximately $4.8

million from this offering, before underwriting commission and other expenses totaling approximately $795,000. The May 2012 warrants, which expire five years from their date of issuance and have an exercise price of $1.04 per share, have been accounted for as equity instruments, since they do not contain features (such as net cash settlement or anti-dilution features) that would preclude the Company from accounting for these warrants as equity.

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11. Stockholders Equity (continued)

2014 Shelf Registration Statement

On January 31, 2014, the Company filed a Shelf Registration Statement on Form S-3 (the 2014 Shelf Registration Statement) with the SEC to sell up to $100 million of shares of common stock. This registration statement (file No. 333-193699) was declared effective by the SEC on March 19, 2014. The Company has to date conducted the following sales of its securities under the 2014 Shelf Registration Statement:

(a) On April 3, 2014, the Company filed a prospectus supplement and offered for sale 13,023,750 shares of its common stock at a price of $2.21 per share in an underwritten public offering. The Company received gross proceeds in the public offering of approximately $28.8 million before underwriting commission and incurred expenses of approximately $2.1 million.

(b) Subsequent to year end, on February 4, 2015, the Company filed a prospectus supplement and offered for sale 11,500,000 shares of its common stock at a price of $3.25 per share in an underwritten public offering. The Company received gross proceeds in the public offering of approximately $37.4 million before underwriting commission and incurred expenses of approximately $2.7 million. (See Note 15).

Following the February 2015 offering, there is approximately $33.8 million available for future sale under the 2014 Shelf Registration Statement. If the Company s public float (the market value of its common stock held by non-affiliate stockholders) falls below $75 million, the Company will be subject to a further limitation under which it can sell no more than one-third (1/3) of its public float during any 12-month period. Further, the number of shares that the Company can sell at any one time may be limited under certain circumstances to 20% of the outstanding common stock under applicable NASDAQ marketplace rules.

Warrant Exercises

During the years ended December 31, 2014 and 2013, the Company issued an aggregate of 1,262,696 and 3,862,250 shares of its authorized but unissued common stock upon the exercise of previously issued common stock purchase warrants, raising gross proceeds of $1,316,503 and $4,083,300, respectively.

BioMarin convertible promissory note automatic conversion into common stock shares

On October 26, 2012, the Company entered into a note purchase agreement with BioMarin, pursuant to which the Company issued BioMarin a convertible promissory note in the principal amount of $5 million. (See Note 8). The $5 million note automatically converted into 6,666,667 shares of the Company s common stock (at a price of $0.75 per share) on December 10, 2012.

Stockholder Rights Plan

On September 20, 2011, the Board of Directors approved the Company s adoption of a Stockholder Rights Plan. Under the Plan, a dividend of one preferred share purchase right (a Right) was declared for each share of common stock of the Company that was outstanding on October 7, 2011. Each Right entitles the holder to purchase from the Company one one-hundredth of a share of Series A Junior Preferred Stock at a purchase price of $7.80, subject to adjustment.

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11. Stockholders Equity (continued)

The Rights will trade automatically with the common stock and will not be exercisable until a person or group has become an acquiring person by acquiring 17.5% or more of the Company s outstanding common stock, or a person or group commences, or publicly announces a tender offer that will result in such a person or group owning 17.5% or more of the Company s outstanding common stock. Upon announcement that any person or group has become an acquiring person, each Right will entitle all rightholders (other than the acquiring person) to purchase, for the exercise price of $7.80, a number of shares of the Company s common stock having a market value equal to twice the exercise price. Rightholders would also be entitled to purchase common stock of the acquiring person having a value of twice the exercise price if, after a person had become an acquiring person, the Company were to enter into certain mergers or other transactions. If any person becomes an acquiring person, the Board of Directors may, at its option and subject to certain limitations, exchange one share of common stock for each Right.

The Rights have certain anti-takeover effects, in that they would cause substantial dilution to a person or group that attempts to acquire a significant interest in the Company on terms not approved by the Board of Directors. In the event that the Board of Directors determines a transaction to be in the best interests of the Company and its stockholders, the Board of Directors may redeem the Rights for $0.001 per share at any time prior to a person or group becoming an acquiring person. The Rights will expire on September 20, 2016, unless earlier redeemed or exchanged.

12. Stock Compensation Plans

The Company issues options, restricted stock, stock appreciation rights and restricted stock units (collectively, the Awards) to employees, directors, consultants and scientific advisors of the Company under the 2006 and 2014 Stock Incentive Plans (the 2006 Plan and the 2014 Plan or collectively, the Plans). Prior to July 2006, the Company granted options pursuant to written agreements to purchase an aggregate of 2,352,254 shares of common stock. At December 31, 2014, no shares remain available for future issuance under the 2006 Plan. On February 27, 2014, the Company s Board of Directors approved the adoption of the Catalyst Pharmaceutical Partners, Inc. 2014 Stock Incentive Plan . The 2014 Plan became effective upon stockholder approval of the 2014 Plan at the Company s 2014 Annual Meeting of Stockholders held on May 15, 2014. Under the Plan, 4,000,000 shares were reserved for issuance under the 2014 Plan and as of December 31, 2014, 2,640,000 shares remain available for future issuance under the 2014 Plan.

Stock Options

The Company has granted stock options to employees, officers, directors, scientific advisors and consultants generally at exercise prices equal to the market price of the common stock at grant date. Option awards generally vest over a period of 2 to 4 years of continuous service and have contractual terms from 5 to 10 years. Certain awards provide for accelerated vesting if there is a change in control. The Company issues new shares as shares are required to be delivered upon exercise of outstanding stock options.

During the year ended December 31, 2014, options to purchase 580,000 shares of the Company s common stock were exercised with proceeds of $522,000. Further, during the year ended December 31, 2014, options to purchase 185,000 shares of the Company s common stock were exercised on a cashless basis, resulting in the issuance of an aggregate of 119,709 shares of the Company s common stock.

During the year ended December 31, 2013, options to purchase 50,000 shares of the Company s common stock were exercised with proceeds of $23,500.

During the years ended December 31, 2014, 2013 and 2012 the Company recorded non-cash stock-based compensation expense related to stock options totaling $767,838, $175,855 and $340,039, respectively.

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12. Stock Compensation Plans (continued)

During the year ended December 31, 2014, the Company granted five and seven-year options to purchase an aggregate of 1,305,000 shares of the Company s common stock to certain of the Company s officers, employees, directors, and consultants. During the years ended December 31, 2013 and 2012, the Company granted five-year options to purchase an aggregate of 115,000 shares and 975,000 shares, respectively, of the Company s common stock to certain of the Company s officers, employees, directors and consultants.

Stock option activity under the Company s written stock option agreements and the Plans for the year ended December 31, 2014 is summarized as follows:

	Number of Options	Weighted Average Exercise Price	Weighted Average Remaining Contractual Term (in years)	Aggregate Intrinsic Value
Outstanding at beginning of year	3,428,906	$ 0.80		
Granted	1,305,000	3.08		
Exercised	(765,000)	0.90		
Forfeited or cancelled	(50,000)	2.71		
Expired	(34,296)	3.28		
Outstanding at end of year	3,884,610	$ 1.50	3.29	$ 5,897,040
Exercisable at end of year	2,687,943	$ 0.86	1.91	$ 5,703,106

Other information pertaining to stock option activity during the years ended December 31, 2014, 2013 and 2012 was as follows:

	2014	2013	2012
Weighted average fair value of granted stock options	$ 2.41	$ 0.48	$ 0.32
Total fair value of vested stock options	$ 409,476	$ 166,633	$ 348,815
Total intrinsic value of exercised stock options	$ 1,339,100	$ 17,975	$ 40,050

The following table summarizes information about the Company s options outstanding at December 31, 2014:

Range of Exercise Prices	Options Outstanding			Options Exercisable		
	Number Outstanding	Weighted Average Remaining Contractual Life	Weighted Average Exercise Price	Number Exercisable	Weighted Average Remaining Contractual Life	Weighted Average Exercise Price

		(Years)				**(Years)**		
$0.47	1,000,000	2.97	$	0.47	950,000	2.95	$	0.47
$0.69	729,610	0.17	$	0.69	729,610	0.17	$	0.69
$0.85	40,000	3.39	$	0.85	13,333	3.39	$	0.85
$1.07- $1.09	860,000	1.48	$	1.08	860,000	1.48	$	1.08
$2.34- $2.35	30,000	4.39	$	2.35	10,000	4.24	$	2.34
$3.03- $3.12	1,225,000	6.67	$	3.12	125,000	6.66	$	3.12
	3,884,610	3.29	$	1.50	2,687,943	1.91	$	0.86

As of December 31, 2014, there was approximately $2,400,000 of unrecognized compensation expense related to non-vested stock option awards granted under the Plans. That cost is expected to be recognized over a weighted average period of approximately 2.5 years.

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12. Stock Compensation Plans (continued)

The Company utilizes the Black-Scholes option-pricing model to determine the fair value of stock options on the date of grant. This model derives the fair value of stock options based on certain assumptions related to the expected stock price volatility, expected option life, risk-free interest rate and dividend yield. Expected volatility is based on reviews of historical volatility of the Company s common stock. The estimated expected option life is based upon estimated employee exercise patterns and considers whether and the extent to which the options are in-the-money. The Company estimates the expected option life for options granted to employees and directors based upon the simplified method. Under this method, the expected life is presumed to be the mid-point between the vesting date and the end of the contractual term. The Company will continue to use the simplified method until it has sufficient historical exercise data to estimate the expected life of the options. The risk-free interest rate assumption is based upon the U.S. Treasury yield curve appropriate for the estimated life of the stock options awards. The expected dividend rate is zero. Stock based compensation expense also includes an estimate, which the Company makes at grant date, of the number of awards that are expected to be forfeited. The Company revises this estimate in subsequent periods if actual forfeitures differ from those estimates.

Assumptions used during the years were as follows:

	Year ended December 31,		
	2014	**2013**	**2012**
Risk free interest rate	1.18% to 2.03%	0.45% to 0.53%	0.28% to 0.66%
Expected term	3 to 7 years	3 years	3 to 5 years
Expected volatility	115%	137%	120%
Expected dividend yield	%	%	%
Expected forfeiture rate	%	%	%

Restricted Stock Units

Under the 2014 Plan, participants may be granted restricted stock units, each of which represents a conditional right to receive shares of common stock in the future. The restricted stock units granted under this plan generally vest ratably over a three to four-year period. Upon vesting, the restricted stock units will convert into an equivalent number of shares of common stock. The amount of expense relating to the restricted stock units is based on the closing market price of the Company s common stock on the date of grant and is amortized on a straight-line basis over the requisite service period. There was no restricted stock unit activity during 2013 or 2012. Restricted stock unit activity during 2014 was as follows:

	2014	
	Number of Restricted Stock Units	**Weighted Average Grant Date Fair Value**
Nonvested balance at beginning of year		
Granted	80,000	$ 2.83
Vested		

Forfeited			
Nonvested balance at end of year	80,000	$	2.83

During the years ended December 31, 2014, 2013 and 2012, the Company recorded non-cash stock-based compensation expense related to restricted stock units totaling $10,131, $0 and $0, respectively.

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13. Benefit Plan

The Company maintains an employee savings plan pursuant to Section 401(k) of the Internal Revenue Code covering all eligible employees. Subject to certain dollar limits, eligible employees may contribute up to 15% of their pre-tax annual compensation to the plan. The Company has elected to make discretionary matching contributions of employee contributions up to 4% of an employee s gross salary. For the years ended December 31, 2014, 2013 and 2012, the Company s matching contributions were approximately $44,000, $30,000 and $28,000, respectively.

14. Quarterly Financial Information (unaudited)

The following table presents unaudited supplemental quarterly financial information for the years ended December 31, 2014 and 2013:

	Quarter Ended			
	March 31, 2014	June 30, 2014	September 30, 2014	December 31, 2014
Revenues	$	$	$	$
Loss from operations	(3,508,365)	(2,990,173)	(4,109,029)	(3,983,861)
Change in fair value of warrants liability	(335,514)	(223,591)	(906,787)	472,026
Net loss	(3,811,119)	(3,198,020)	(5,009,892)	(3,490,030)
Loss per share basic and diluted	$ (0.07)	$ (0.05)	$ (0.07)	$ (0.05)

	Quarter Ended			
	March 31, 2013	June 30, 2013	September 30, 2013	December 31, 2013
Revenues	$	$	$	$
Loss from operations	(1,705,430)	(2,653,529)	(3,245,776)	(2,706,923)
Change in fair value of warrants liability	(45,326)	(498,587)	(2,676,601)	1,330,155
Net loss	(1,744,289)	(3,143,590)	(5,912,059)	(1,354,658)
Loss per share basic and diluted	$ (0.04)	$ (0.08)	$ (0.13)	$ (0.03)

Quarterly basic and diluted net loss per common share were computed independently for each quarter and do not necessarily total to the full year basic and diluted net loss per common share.

15. Subsequent Event

Subsequent to year end, on February 4, 2015, the Company filed a prospectus supplement and offered for sale 11,500,000 shares of its common stock at a price of $3.25 per share in an underwritten public offering. The Company received gross proceeds in the public offering of approximately $37.4 million before underwriting commission and incurred expenses of approximately $2.7 million. (See Note 11).

Subsequent to year-end, the Company issued an aggregate of 152,174 shares of its authorized but unissued common stock upon the exercise of previously issued common stock purchase warrants that were issued in October 2011, raising gross proceeds of approximately $198,000. Additionally, subsequent to year end, stock options to purchase

829,608 shares of the Company s common stock were exercised on a cashless basis, resulting in the issuance of an aggregate of 673,583 shares of the Company s common stock.