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, 2007

Commission file number 1-08246

Southwestern Energy Company

(Exact name of Registrant as specified in its charter)

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

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

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. Yes ☒ No ☐

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

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

Large accelerated filer ☒ Accelerated filer ☐ Non-accelerated filer ☐ Smaller reporting company ☐

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

The aggregate market value of the voting stock held by non-affiliates of the registrant was $7,412,186,555 based on the New York Stock Exchange – Composite Transactions closing price on June 30, 2007, of $44.50. For purposes of this calculation, the registrant has assumed that its directors and executive officers are affiliates.

As of February 22, 2008, the number of outstanding shares of the registrant's Common Stock, par value $0.01, was 170,971,532.

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 6, 2008 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, 2007

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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.

ITEM 1. BUSINESS

Southwestern Energy Company is an independent energy company primarily engaged in the exploration for and production of natural gas within the United States. We also focus on creating and capturing additional value through our natural gas gathering and marketing businesses, which we refer to as our Midstream Services. We operate principally in three segments – Exploration and Production, or E&P, Midstream Services and Natural Gas Distribution:

- *Exploration and Production* - Our primary business is natural gas and oil exploration, development and production within the United States, with operations principally located in Arkansas, Oklahoma and Texas. Our operations are primarily conducted through our wholly-owned subsidiaries, SEECO, Inc. and Southwestern Energy Production Company, or SEPCO. SEECO operates exclusively in Arkansas, holds a large base of both developed and undeveloped gas reserves and conducts both the drilling program for the Fayetteville Shale play and the ongoing 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 and in Texas. 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 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. Our gathering subsidiary, DeSoto Gathering Company, L.L.C., engages in gas gathering activities primarily related to the development of our Fayetteville Shale play. Our gas marketing subsidiary, Southwestern Energy Services Company, or SES, captures downstream opportunities which arise through marketing and transportation activity.

- *Natural Gas Distribution* - Our wholly-owned subsidiary, Arkansas Western Gas Company, or AWG, operates integrated natural gas distribution systems in northern Arkansas serving approximately 152,000 retail customers. On November 14, 2007, we announced that we had entered into a definitive agreement for the sale of AWG to SourceGas LLC for $224 million plus working capital. Upon the consummation of the pending sale of AWG, we will cease to have any natural gas distribution operations. Subject to regulatory approval, the sale is expected to close approximately mid-year 2008.

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 2007, 94% of our operating income and 95% of our EBITDA were generated from our E&P business. Our Midstream Services and Natural Gas Distribution segments each generated 3% of our operating income and 3% and 2%, respectively, of our EBITDA in 2007. In 2006, 96% of our operating income and 93% of our EBITDA were generated from our E&P business. In 2006, our Midstream Services and Natural Gas Distribution segments each generated 2% of our operating income and 1% and 3%, respectively, of our EBITDA. In 2005, our E&P, Midstream Services and Natural Gas Distribution segments generated 95%, 3% and 2% of our operating income and 94%, 3% and 3% of our EBITDA, respectively. 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 E&P business strategy are:

- *Exploit and Develop Our Existing Asset Base*. We seek to maximize the value of our existing asset base by developing properties that have production and reserve growth potential while also controlling per unit production costs. Our primary focus is our Fayetteville Shale play, where we hold approximately 906,700 net acres. We believe our large acreage position holds significant production and reserve growth potential. We intend to continue to develop our acreage position by accelerating our drilling program and by improving individual well results through the use of advanced technologies and detailed technical analysis of our properties. Approximately 95% of the $61 million budgeted for seismic and other geological and geophysical, or G&G, expenditures in 2008 will be allocated to our Fayetteville Shale acreage to acquire an additional 370 square miles of three-dimensional (3-D) seismic data. This, along with approximately 525 square miles of 3-D seismic data that we have acquired through December 31, 2007, will give us seismic data on approximately 45% of our net acreage position in the Fayetteville Shale.

- *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. In addition, we are building a sizeable gas gathering system in the Fayetteville Shale play that will allow us to reduce our per unit production costs.

- *Control Operations and Costs.* 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 and oil production to maximize both production volumes and wellhead price.

- *Hedge Production to Stabilize Cash Flow*. As of December 31, 2007, the average proved reserves-to-production ratio, or reserve life, of our estimated proved reserves was approximately 12.8 years. Our long-lived reserves provide us with relatively predictable production. We maintain an active natural gas hedging program on our production to protect cash flows that we use for capital investments. As of December 31, 2007, we had hedges in place on approximately 102.0 Bcf of 2008 gas production (representing approximately 70% of our targeted 2008 production) and 79.0 Bcf of 2009 gas production. Additionally, we have financially protected 91.3 Bcf and 3.6 Bcf for 2008 and 2009, respectively, in order to reduce the effects of changes in market differentials on prices we receive on future gas production volumes.

- *Grow Through New Exploration and Development Activities*. We actively seek to find and develop new conventional natural gas and oil properties, as well as new unconventional resource plays, with significant exploration and exploitation potential which we refer to as New Ventures. New prospects are evaluated primarily based on repeatability, multi-well potential and land availability as well as other criteria. Our Fayetteville Shale play began as a New Venture project in 2002. As of December 31, 2007, we held 156,465 net undeveloped acres in New Ventures, which includes approximately 88,000 net undeveloped acres targeting the Devonian-aged Marcellus Shale in Appalachia, where we intend to initiate drilling in 2008.

Recent Developments

Senior Note Offering. In January 2008, we completed a private placement offering of $600 million principal amount of 7.5% Senior Notes due 2018. The net proceeds of the offering were used to repay a portion of the amounts outstanding under our revolving credit facility.

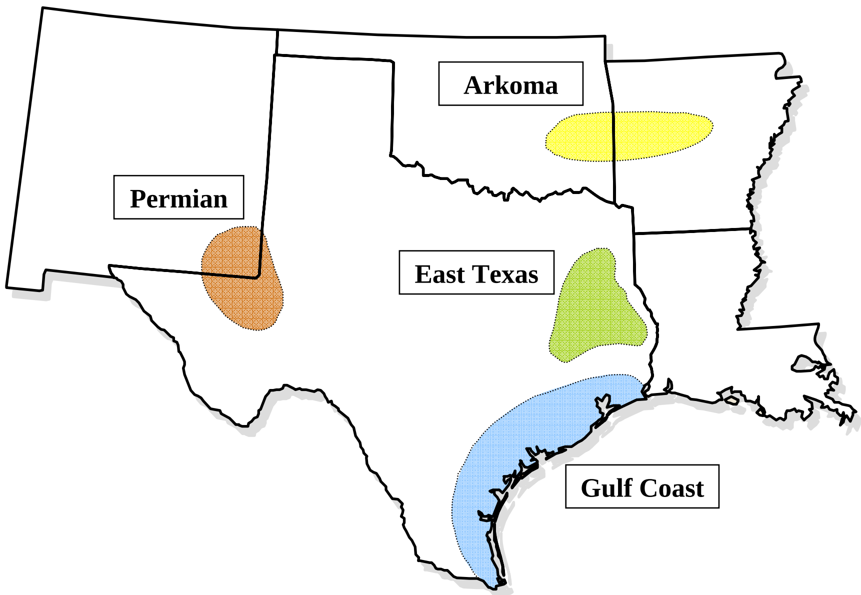
2008 Planned Capital Investments and Production Guidance. On December 19, 2007, we announced a planned capital investment program for 2008 of $1.46 billion, which includes $1.33 billion for our E&P segment, $101 million for our Midstream Services segment, and $25 million for our Natural Gas Distribution segment and other corporate purposes. Our 2008 capital program is expected to be primarily funded by internally-generated cash flow, borrowings under our revolving credit facility and/or funds raised in the public debt markets, proceeds from the sale of AWG and divestitures of certain E&P assets. We also announced our targeted 2008 gas and oil production of approximately 148.0 to 152.0 Bcfe, an increase of approximately 30 to 35% over our 2007 production.

Sale of AWG. On November 9, 2007, we entered into a definitive agreement with SourceGas LLC, pursuant to which SourceGas has agreed to purchase all of the capital stock of AWG for $224 million plus working capital, subject to possible adjustment based on a "seasonality factor" that could reduce the purchase price by up to 2.5% depending upon when the transaction closes. Subject to regulatory approval, the transaction is expected to close approximately mid-year 2008. Upon consummation of the sale, we will cease to engage in the natural gas distribution business.

Amendment of Revolving Credit Facility. On October 12, 2007, we entered into an amendment of our revolving credit facility pursuant to which, among other things, (i) the amount by which our revolving credit facility could be increased through the "accordion" feature was raised from $250 million to $500 million (thereby increasing the maximum aggregate borrowing capacity under our revolving credit facility from $1 billion to $1.25 billion) and (ii) our subsidiaries (other than AWG) were provided with the ability, without limit, to guarantee our indebtedness. In connection with the amendment, we partially exercised our option under the "accordion" feature and increased our current borrowing capacity from $750 million to $1 billion.

Exploration and Production

Historically, we have operated our E&P business in four primary regions — the Arkoma Basin, East Texas, the Permian Basin and the onshore Gulf Coast. In 2008, our operations will primarily be focused in the Arkoma Basin and East Texas. We will continue to actively seek to develop new conventional exploration projects as well as unconventional plays with significant exploration and exploitation potential.



Operating income from our E&P segment was $358.1 million in 2007, up from $237.3 million in 2006 and $234.8 million in 2005. EBITDA from our E&P segment was $640.5 million in 2007, compared to $386.4 million in 2006 and $325.9 million in 2005. The increases in both our operating income and EBITDA in 2007 and 2006 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.

Our estimated proved natural gas and oil reserves were 1,450 Bcfe at year-end 2007, compared to 1,026 Bcfe at year-end 2006 and 827 Bcfe at year-end 2005. 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 accelerated development of our Overton Field in East Texas and our continued conventional drilling program in the Arkoma Basin. The after-tax PV-10, or standardized measure of discounted future net cash flows relating to proved gas and oil reserve quantities, was $2.0 billion at year-end 2007, compared to $1.0 billion at year-end 2006 and $1.4 billion at year-end 2005. The reconciling difference in after-tax PV-10 and pre-tax PV-10 (a non-GAAP measure which is reconciled in the 2007 Summary Operating Data table below) is the discounted value of future income taxes on the estimated cash flows. Our year-end 2007 estimated proved reserves had a present value of estimated future net cash flows before income tax, or pre-tax PV-10, of $2.6 billion, compared to $1.3 billion at year-end 2006 and $2.0 billion at year-end 2005. 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. The decrease in year-end 2006 pre-tax and after-tax PV-10 values of our reserves as compared to year-end 2005 is primarily due to a lower market price for natural gas at December 31, 2006. At year-end 2007, the market prices for natural gas and crude oil that were used to calculate our PV-10 value were $6.80 per Mcf and $92.50 per barrel, respectively, compared to $5.64 per Mcf and $57.25 per barrel at year-end 2006 and $10.08 per Mcf and $61.04 per barrel at year-end 2005. We refer you to Note 7 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 96% of our year-end 2007 estimated proved reserves were natural gas and 64% were classified as proved developed, compared to 95% and 65%, respectively, in 2006. We operate approximately 90% of our reserves, based on our PV-10 value, and our average reserve life approximated 12.8 years at year-end 2007. Sales of natural gas production accounted for 94% of total operating revenues for this segment in 2007, 91% in 2006 and 92% in 2005. Natural gas production has generated a substantial portion of total operating revenues as a result of the natural gas focus of our capital investments in the past three years.

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 exceeded 300% for the last three years, including 2007 where our results were primarily driven by reserve additions associated with our Fayetteville Shale play. In 2007, we replaced 474% of our production volumes by adding 507.9 Bcfe of proved natural gas and oil reserves and having net upward revisions of 31.0 Bcfe. Of the 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 and 2005, our reserve replacement ratios were 386% (from reserve additions of 365.5 Bcfe primarily driven by additions resulting from our drilling programs in the Fayetteville Shale play, East Texas and conventional Arkoma) and 399% (from reserve additions of 274.7 Bcfe primarily driven by additions resulting from our drilling programs in East Texas and conventional Arkoma), respectively, including net downward reserve revisions of 86.6 Bcfe in 2006 and 31.7 Bcfe in 2005. Of the 2006 reserve additions, 153.6 Bcfe were proved developed and 211.9 Bcfe were proved undeveloped. Of the 2005 reserve additions, 107.4 Bcfe were proved developed and 167.3 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. The downward reserve revisions in 2005 were primarily due to adjustments to the terminal decline rates for wells at our Overton Field and declines associated with our Gulf Coast properties.

For the period ending December 31, 2007, our three-year average reserve replacement ratio, including revisions, was 430%. Our reserve replacement ratio for 2007, excluding the effect of reserve revisions, was 447%, compared to 505% in 2006 and 450% in 2005. Excluding reserve revisions, our three-year average reserve replacement ratio is 465%.

Since 2000, the substantial majority of our reserve additions have been generated from our drilling programs in the conventional Arkoma Basin, East Texas and, more recently, the Fayetteville Shale play. We expect these drilling programs to continue to be a major 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 change” and “Our exploration, development and drilling efforts and our operations 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.

In addition, proved undeveloped reserves will require us to make significant additional investments. We expect that our proved undeveloped reserves of 526 Bcfe as of December 31, 2007, will require us to invest an additional $995 million in order for those reserves to be brought to production. Our proved undeveloped reserve additions during 2007 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. We refer you to the risk factors “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.

The following table provides information as of December 31, 2007, related to proved reserves, well count, net acreage and PV-10, and 2007 annual information as to production and capital investments, for each of our operating areas, for our New Ventures and overall:

2007 SUMMARY OPERATING DATA

	Arkoma						
	Conventional	**Fayetteville Shale Play**	**East Texas**	**Permian**	**Gulf Coast**	**New Ventures**	**Total**
Estimated Proved Reserves:							
Total Reserves (Bcfe)	304	716	353	60	12	5	1,450
Percent of Total	21%	49%	24%	4%	1%	1%	100%
Percent Natural Gas	100%	100%	97%	31%	96%	100%	96%
Percent Proved Developed	77%	43%	91%	79%	100%	100%	64%
Production (Bcfe)	23.8	53.5	29.9	4.7	1.4	0.3	113.6
Capital Investments (millions)[1]	$148	$960	$201	$20	$4	$42	$1,375
Total Gross Producing Wells	1,098	497	466	406	34	14	2,515
Total Net Producing Wells	550	377	392	138	12	9	1,478
Total Net Acreage	491,791[2]	781,300[3]	118,904[4]	37,400	8,837	168,236[5]	1,606,468
Net Undeveloped Acreage	299,599[2]	637,560[3]	91,148[4]	8,944	5,795	156,465[5]	1,199,511
PV-10:							
Pre-tax (millions)[6]	$638	$1,038	$659	$212	$33	$12	$2,592
PV of taxes (millions)[6]	142	231	147	47	7	3	577
After-tax (millions)[6]	$496	$807	$512	$165	$26	$9	$2,015
Percent of Total	25%	40%	25%	8%	1%	1%	100%
Percent Operated	85%	96%	99%	49%	33%	81%	90%

(1) Our Total and Fayetteville Shale play capital investments exclude $5 million related to the purchase of drilling rig related equipment.

(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 in the table above.

(3) Assuming successful wells are not drilled and leases are not extended, leasehold expiring over the next three years will be 16,561 acres in 2008, 96,601 acres in 2009 and 145,722 acres in 2010.

(4) Assuming successful wells are not drilled to develop the acreage and leases are not extended, leasehold expiring over the next three years will be 7,737 acres in 2008, 33,274 acres in 2009 and 4,474 acres in 2010.

(5) Includes New Ventures opportunities such as the Marcellus Shale play in Pennsylvania.

(6) 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.

We refer you to Note 7 in the 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.

Arkoma Basin

We have traditionally operated in a portion of the Arkoma Basin located in western Arkansas that is primarily within the boundaries of our utility gathering system, which 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. Our drilling program in the Arkoma Basin is comprised of both conventional and unconventional activities. We refer to our drilling program targeting stratigraphic Atokan-age objectives in Oklahoma and Arkansas as the "conventional Arkoma" drilling program. Our Fayetteville Shale play represents our unconventional drilling program in the Arkoma Basin. At December 31, 2007, we had approximately 1,020 Bcf of natural gas reserves in the Arkoma Basin, representing approximately 70% of our total reserves, up from 577 Bcf at year-end 2006 and 372 Bcf at year-end 2005.

Fayetteville Shale Play. Our Fayetteville Shale play, which we announced in August 2004, 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. Approximately 716 Bcf of our reserves at year-end 2007 were attributable to our Fayetteville Shale play, up from approximately 300 Bcf in 2006 and 101 Bcf in 2005. Gross production from our operated wells in the Fayetteville Shale play increased from approximately 100 MMcf per day at the beginning of 2007 to approximately 325 MMcf per day by year-end. Approximately 15 MMcf per day of our production at December 31, 2007, was from 10 wells producing from conventional reservoirs located in four separate counties. Our net production from the Fayetteville Shale play was 53.5 Bcf in 2007, compared to 11.8 Bcf in 2006 and 1.8 Bcf in 2005. Our production in 2008 is estimated to range between 90 and 95 Bcf from the Fayetteville Shale.

At December 31, 2007, we held approximately 906,700 net acres in the play area (637,560 net undeveloped acres, 143,740 net developed acres held by Fayetteville Shale production and approximately 125,400 net acres held by conventional production). 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 2007, approximately 18% 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 "We may have difficulty drilling all of the wells that are necessary to hold our Fayetteville Shale acreage before the initial lease terms expire, which could result in the loss of certain leasehold rights" in Item 1A of Part I of this Form 10-K. Excluding our acreage held by conventional production, our acreage position as of December 31, 2007 had an average lease term of 6 years, an average royalty interest of 15% and was obtained at an average cost of $116 per acre. For more information about acreage and well count, we refer you to "Properties" in Item 2 of Part I of this Form 10-K.

In 2006, the Arkansas Oil and Gas Commission 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. We refer you to the risk factor "We may have difficulty drilling all of the wells that are necessary to hold our Fayetteville Shale acreage before the initial lease terms expire, which could result in the loss of certain leasehold rights" in Item 1A of Part I of this Form 10-K.

As of December 31, 2007, we had spud a total of 699 wells in the play, 601 of which were operated by us and 98 of which were outside-operated wells. Of the wells spud, 415 were in 2007, 196 were in 2006 and 67 were in 2005. Of the wells spud in 2007, 410 were designated as horizontal wells. At year-end 2007, 478 wells had been drilled and completed, including 415 horizontal wells. Of the 415 horizontal wells, 372 wells were fracture stimulated using either slickwater or crosslinked gel stimulation treatments, or a combination thereof.

Our total proved net gas reserves booked in the play at year-end 2007 were 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. Of the 935 locations, 871 were horizontal. Our proved developed reserves have ranged from less than 100,000 Mcf to 4.7 Bcf per well and the average gross proved reserves for the wells included in our year-end reserves was approximately 1.5 Bcf, compared to 1.15 Bcf per well at the end of 2006 and 0.95 Bcf per well at the end of 2005. 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 nonproducing and 263 were proved undeveloped. Total proved gas reserves booked in the play in 2005 totaled 101 Bcf from a total of 177 locations, of which 54 were proved developed producing, 6 were proved developed non-producing and 117 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.

Since we announced our discovery of the play in 2004, we have progressively increased our capital investments in the area resulting in significant growth in our production and reserves over the past three years. In 2007, we invested approximately $960 million in our Fayetteville Shale play, which included $789 million to spud 415 wells, resulting in reserve additions of 401.6 Bcf. Previous reserve estimates were further revised upward in 2007 by 67.9 Bcfe due primarily to improved well performance. In addition, we invested $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 2005, we invested approximately $119 million, which included $67 million to spud 67 wells, $41 million for leasehold acquisition, $4 million for seismic and $7 million in capitalized costs. In 2008, we plan to invest approximately $1 billion in our Fayetteville Shale play, which includes drilling approximately 475 horizontal wells, approximately 40 vertical wells targeting the shallower conventional reservoirs above the Fayetteville Shale and shooting 3-D seismic over a large portion of our Fayetteville Shale acreage. At December 31, 2007, we had acquired approximately 525 square miles of 3-D seismic data and plan to acquire an additional 370 square miles of 3-D seismic data during 2008, the total of which will give us seismic data on approximately 45% of our net acreage position in the Fayetteville Shale.

We believe that our Fayetteville Shale acreage holds significant development potential. Our strategy going forward is to increase our production through development drilling while also 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, 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 and oil 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.

Conventional Arkoma Program. Our conventional Arkoma drilling program continues to provide a solid foundation for our E&P program and represents a significant percentage of our total production and reserves. Approximately 304 Bcf of our reserves at year-end 2007 were attributable to our conventional Arkoma wells. In 2007, we invested approximately $148 million and participated in 114 wells in our conventional Arkoma properties, of which 81 were successful and 23 were in progress at year-end, resulting in an 89% success rate and adding new reserves of 60.6 Bcf. Prior to 2007, production over the last few years from the basin was fairly constant as new production stemming from our drilling program offset the natural production decline from existing wells. However, in 2007 we experienced 18% growth in our production volumes to 23.8 Bcf, compared to 20.1 Bcf in 2006 and 20.2 Bcf in 2005.

Our strategy in the Fairway is to continue to delineate new geologic prospects and extend previously identified 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. One of these is our Ranger Anticline area, which we refer to as Ranger, located at the southern edge of the Arkansas portion of the basin. Our wells at Ranger have primarily targeted the Upper and Lower Borum tight gas sands between 5,000 and 8,000 feet in depth. We drilled our first successful well at Ranger in 1997 and as our understanding of the geology at Ranger has grown, the potentially productive area in the field has expanded.

From 1997 through year-end 2007, we successfully drilled 156 out of 185 wells at Ranger, adding 114 net Bcf of reserves. During 2007, we successfully completed 52 out of 67 wells at Ranger (excluding 12 wells in progress at year-end), which added 25.5 net Bcf of new reserves. Wells completed in 2007 had average estimated ultimate gross reserves of 1.1 Bcf per well. Net production from the field increased by 67% to 9.5 Bcf during 2007, compared to 5.7 Bcf in 2006 and 5.6 Bcf in 2005. Our average working interest in the 156 successful wells drilled through December 31, 2007, is 76% and our average net revenue interest is 61%. At December 31, 2007, we held approximately 81,920 gross acres at Ranger, of which 19,840 acres were developed. We believe that Ranger holds additional future development potential.

We began drilling at our Midway prospect area located approximately 11 miles north of Ranger two years ago and, through year-end 2006, we had drilled a total of six wells. In 2007, we began to accelerate drilling at Midway with the drilling of 26 wells which were all either productive or in progress at year-end. Our wells at Midway primarily produce from the same productive zones as our wells at Ranger. Depending on the performance of these wells, there may be significant additional drilling potential on our Midway acreage. At year-end 2007, we held approximately 31,000 gross acres in our Midway prospect area.

Our conventional Arkoma Basin drilling program continues to be an important focus for our capital program and we intend to conduct development drilling and workover programs that, at a minimum, will maintain our production and reserve base in this area. In 2008, we plan to invest approximately $132 million in our conventional Arkoma program and will drill approximately 100 to 110 wells, including 40 wells in the Ranger Anticline area and 45 wells in the Midway area.

<u>East Texas</u>

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, 2007, we had approximately 353 Bcfe of reserves in East Texas, representing approximately 24% of our total reserves, compared to 383 Bcfe at year-end 2006 and 369 Bcfe at year-end 2005.

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. When we acquired the field, it was primarily developed on 640-acre spacing, or one well per square mile. Analogous Cotton Valley fields in the area have been drilled to 80-acre spacing, and in some cases to 40-acre spacing. At December 31, 2007, we held approximately 24,400 gross acres in the Overton Field with an average working interest of 96% and an average net revenue interest of 77%.

Our proved reserves in the Overton Field were 315 Bcfe at year-end 2007, compared to 367 Bcfe at year-end 2006 and 353 Bcfe at year-end 2005. In 2007, our drilling program was focused on drilling our proved undeveloped locations in the field. We invested approximately $96 million to drill 45 wells at the Overton Field, all of which were successful, resulting in new reserve additions of 6.6 Bcfe. The 2007 reserve additions at Overton were limited because the reserves from drilling our proved undeveloped locations were already included in our prior years' reserve totals. Additionally in 2007, previous reserve estimates for Overton were revised downward by 33.2 Bcfe due primarily to higher decline rates in newer wells than was expected. In 2006, we invested approximately $155 million to drill 66 wells, all of which were successful, resulting in reserve additions of 88.0 Bcfe, including a net downward reserve revision of 47.2 Bcfe that was primarily a result of comparatively lower year-end gas prices as well as performance revisions in some of our existing wells. In 2005, we invested approximately $158 million to drill 80 wells, all of which were successful, resulting in reserve additions of 82.8 Bcfe, including revisions.

Net production from our Overton Field was 25.1 Bcfe in 2007, compared to 29.8 Bcfe in 2006 and 26.7 Bcfe in 2005. We expect our production from the Overton Field to decline over time due to the fact that the field is now almost fully developed and due to the natural production decline in existing wells.

Angelina River Trend. Our Angelina River Trend properties are concentrated in several separate development areas located primarily in four different counties in East Texas targeting both the Travis Peak and James Lime formation. Our 2007 drilling results include a new discovery at our Jebel prospect area located in Shelby County, Texas, in the James Lime formation and are collectively referred to as Angelina. The Timberstar-Mills 1H horizontal discovery well was completed in December 2007 with an initial production rate of 12.1 MMcf per day and was producing approximately 4.0 MMcf per day as of February 22, 2008. At December 31, 2007, we held approximately 75,755 gross undeveloped acres and 11,456 gross developed acres at Angelina with an average working interest of 72.6% and an average net revenue interest of 55.7%.

Our proved reserves in the Angelina area were 33 Bcfe at year-end 2007, compared to 16 Bcfe at year-end 2006 and 13 Bcfe at year-end 2005. Through December 31, 2007, we had drilled a total of 59 wells at Angelina primarily targeting the Travis Peak or James Lime formations, with all but one well being successful. In 2007, we invested approximately $88 million to drill 31 wells at Angelina, all but one of which were successful or in progress at December 31, 2007, resulting in reserve additions of 22.6 Bcfe. In 2006, we invested approximately $40 million to drill 16 wells, all of which were successful. In 2005, we invested approximately $18.7 million to drill 9 wells, all of which were successful. The average estimated ultimate recovery of gas and oil reserves from new wells completed in 2007 was approximately 1.3 gross Bcfe per well, compared to 0.8 gross Bcfe per well in 2006 and 1.6 gross Bcfe per well in 2005. Net production from our Angelina properties was 2.5 Bcfe in 2007, compared to 1.8 Bcfe in 2006 and 0.9 Bcf in 2005.

In 2008, we plan to invest approximately $122 million to drill approximately 40 wells in East Texas, including 30 to 35 wells in Angelina. Of these wells, we intend to participate in up to 10 to 15 James Lime horizontal wells.

Permian Basin and Gulf Coast

Our Permian Basin properties are primarily located in west Texas and southeast New Mexico. At December 31, 2007, our proved reserves in the Permian Basin were 60 Bcfe, compared to approximately 51 Bcfe at year-end 2006 and 59 Bcfe at year-end 2005. Our production in the basin during 2007 was 4.7 Bcfe, compared to 5.8 Bcfe in 2006 and 6.9 Bcfe in 2005. The decreases in production during both 2007 and 2006 were due to the natural decline in these properties, partially offset by our drilling program. In 2007, we invested $20 million in the Permian Basin and drilled 14 wells, of which 13 were successful, resulting in reserve additions of 11.0 Bcfe. In 2006, we invested $25 million in the Permian Basin and drilled 12 wells, all of which were successful, resulting in reserve additions of 8.5 Bcfe. Our 2006 reserve additions were more than offset by a net downward reserve revision of 10.7 Bcfe related to lower commodity prices at year-end and performance revisions. In 2005, we invested $15 million in the Permian Basin and drilled 16 wells, 15 of which were successful, resulting in reserve additions of 4.7 Bcfe. At year-end 2007, we held approximately 109,468 gross acres in the Permian Basin, with an average working interest of 37% and an average net revenue interest of 30% in the wells in which we participate on this acreage. For more information about acreage and well count, refer to "Properties" in Item 2 of Part I of this Form 10-K.

Our Gulf Coast properties are located onshore in Texas. Proved reserves in our Gulf Coast properties totaled 12 Bcfe at December 31, 2007, compared to approximately 15 Bcfe at year-end 2006 and 27 Bcfe at year-end 2005. Net production from this area in 2007 was 1.4 Bcfe, compared to 2.6 Bcfe in 2006 and 3.9 Bcfe in 2005. The decrease in reserves and production during 2007 was due to the natural decline in these properties. The decline in reserves in 2006 was primarily due to the divestiture of our South Louisiana properties. During the fourth quarter of 2006, we completed the sale of 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. With this divestiture, we no longer have producing properties in the South Louisiana area. In 2007, we invested approximately $4 million in our Texas Gulf Coast properties. In 2006, we invested approximately $7 million that resulted in reserve additions of 0.2 Bcfe which were more than offset by downward reserve revisions. In 2005, we invested approximately $8 million resulting in reserve additions of 3.7 Bcfe which were more than offset by downward revisions of 10.2 Bcfe.

We are currently evaluating the potential divestiture of all or a portion of our properties in the Permian Basin and Gulf Coast to help fund a portion of our 2008 capital investments program.

New Ventures

We have personnel dedicated to the research and identification of active and potential plays, 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 prospects are primarily evaluated based on repeatability, multi-well potential and land availability as well as other criteria.

At December 31, 2007, we held 156,465 net undeveloped acres in areas of the United States outside of our core operating areas in connection with New Ventures that we are pursuing. This compares to 89,592 net undeveloped acres held at year-end 2006 and 116,633 net undeveloped acres held at year-end 2005. Of the 156,465 net undeveloped acres held at year-end 2007, approximately 88,000 net undeveloped acres were located in Pennsylvania in the Marcellus Shale play and approximately 49,500 acres were located in Culberson County, Texas, in the Barnett Shale play in the Permian Basin. We sold our acreage in Culberson County in early 2008 for $6.3 million. 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 18 were successful and 7 were in progress at year-end. We have approximately 32,000 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 drill 7 exploration wells, of which 5 were successful. In 2005, we invested approximately $26 million as part of our New Ventures program to drill 6 exploration wells, of which 4 were successful.

In 2008, we plan to invest approximately $26 million in various New Ventures projects, including drilling 3 vertical test wells in the Marcellus Shale play in Pennsylvania.

Acquisitions and Divestitures

There were no significant acquisitions or divestitures of gas and oil properties in 2007 or 2005.

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. With this divestiture, we no longer have producing properties in the South Louisiana area. 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. In total, we purchased 2.9 Bcfe of proved reserves for $18 million at an average cost of $6.09 per Mcfe. The cost per Mcfe was higher than for prior acquisitions due to the potential existence of future drilling opportunities that were not classified as proved.

Capital Investments

During 2007, we invested a total of $1.38 billion in our E&P business and participated in drilling 653 wells, 439 of which were successful, 17 were dry and 197 were in progress at year-end. Of the 197 wells in progress at year-end, 141 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 70%, 15%, and 11% of our E&P capital investments in 2007, respectively. We invested approximately $960 million in our Fayetteville Shale play, $201 million in East Texas, $148 million in our conventional Arkoma Basin program, $20 million in the Permian Basin, $4 million in the Gulf Coast and $42 million in New Ventures.

Of the $1.38 billion invested in 2007, approximately $1.13 billion was invested in exploratory and development drilling and workovers, $66 million for leasehold acquisition, $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. In 2005, we invested approximately $451 million in our E&P business, including $35 million related to the construction of drilling rigs, and participated in drilling 247 wells. The increases in capital investments and wells drilled over the last two years are primarily due to the acceleration of our drilling program in the Fayetteville Shale play.

In 2008, we plan to invest approximately $1.33 billion in our E&P program and participate in drilling between 650 and 680 wells. The Fayetteville Shale play will be the primary focus of our capital investments, where we plan to invest approximately $1 billion in 2008. Our capital investments in 2008 will also include approximately $122 million in East Texas, approximately $132 million in our conventional drilling program in the Arkoma Basin, and $26 million in New Ventures projects.

Of the $1.33 billion allocated to our 2008 E&P capital budget, approximately $1.09 billion will be invested in development and exploratory drilling, $61 million in seismic and other G&G expenditures (including approximately $58 million in our Fayetteville Shale play), $42 million in leasehold, and $142 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 2008.

Other Revenues

Other revenues and operating income for 2007, 2006 and 2005 included pre-tax gains of $6.4 million, $4.0 million and $3.1 million, respectively, related to the sale of gas-in-storage inventory.

Sales and Major Customers

Our daily natural gas equivalent production averaged 311.1 MMcfe in 2007, compared to 198.1 MMcfe in 2006 and 167.1 MMcfe in 2005. Total natural gas equivalent production was 113.6 Bcfe in 2007, compared to 72.3 Bcfe in 2006 and 61.0 Bcfe in 2005. Our natural gas production was 109.9 Bcf in 2007, compared to 68.1 Bcf in 2006 and 56.8 Bcf in 2005. 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 2.1 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 614,000 barrels of oil in 2007, compared to 698,000 barrels of oil in 2006 and 705,000 barrels of oil in 2005. Our oil production decreased during 2007 due to the sale of our South Louisiana properties in the fourth quarter of 2006. For 2008, we are targeting total natural gas and crude oil production of approximately 148.0 to 152.0 Bcfe, which equates to a growth rate of approximately 30% to 35% above our 2007 production volumes.

The majority of our gas production and all of our oil production is sold to unaffiliated purchasers. These combined gas and oil sales to unaffiliated purchasers accounted for 96% of total E&P revenues in 2007, 92% in 2006, and 90% in 2005. In 2007, our largest unaffiliated purchaser accounted for approximately 2% of total E&P revenues.

Our utility subsidiary, AWG, also purchases a portion of our gas production. These sales are made by SEECO primarily under contracts obtained under a competitive bidding process. We refer you to “Natural Gas Distribution — Gas Purchases and Supply” for further discussion of these contracts. Sales to AWG accounted for approximately 4% of total E&P revenues in 2007, 7% in 2006, and 9% in 2005. SEECO’s sales to AWG were 4.8 Bcf in 2007, compared to 4.7 Bcf in 2006 and 5.1 Bcf in 2005. Sales to AWG are primarily driven by the utility’s changing supply requirements due to variations in the weather and SEECO’s ability to obtain gas supply contracts that are periodically placed out for competitive bids. SEECO’s gas production provided approximately 36% of the utility’s requirements in 2007, 41% in 2006, and 38% in 2005. We also sell gas directly to industrial and commercial transportation customers located on AWG’s gas distribution systems. SEECO also owns an unregulated natural gas storage facility that has historically been utilized to help meet its peak seasonal sales commitments. The storage facility is connected to AWG’s distribution system. We expect future increases in sales of our gas production to come primarily from sales to unaffiliated purchasers. Future sales to AWG will be dependent upon our success in obtaining gas supply contracts from them. 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 of both affiliated and unaffiliated customers for our production.

We realized an average wellhead price of $6.80 per Mcf for our natural gas production in 2007, compared to $6.55 per Mcf in 2006 and $6.51 per Mcf in 2005, including the effect of hedges. Our hedging activities increased our average gas price $0.64 per Mcf in 2007 and $0.18 per Mcf in 2006 and decreased our average gas price $1.22 per Mcf in 2005. Our average oil price realized was $69.12 per barrel in 2007, compared to $58.36 per barrel in 2006 and $42.62 per barrel in 2005, including the effect of hedges. None of our crude oil production was hedged during 2007. Our hedging activities lowered our average oil price $4.81 per barrel in 2006 and $11.75 per barrel in 2005.

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, 2007, we had hedges in place on 102.0 Bcf, or approximately 70% of our targeted 2008 gas production, and 79.0 Bcf of our expected 2009 gas production. Subsequent to December 31, 2007 and prior to February 22, 2008, we hedged 16.0 Bcf of 2008, 17.0 Bcf of 2009 and 16.0 Bcf of 2010 gas production under fixed price swaps with average prices of $8.99, $8.53 and $8.55 per Mcf, respectively. In addition, we hedged 8.0 Bcf of 2009 and 2.0 Bcf of 2010 gas production using costless collars. The collars relating to 2009 production have a weighted average floor and ceiling price of $8.00 and $10.05 per Mcf, respectively; and the collars relating to 2010 production have a weighted average floor and ceiling price of $8.50 and $10.20 per Mcf, respectively. As of February 22, 2008, we have hedged approximately 80% of our 2008 anticipated gas production. At February 22, 2008, we did not have hedges in place for any of our oil production for 2008, 2009, or 2010. 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, 2007.

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. In 2007, the difference in our average price received was approximately $0.70 per Mcf lower than average NYMEX spot market prices, disregarding the impact of hedges. In 2006 and 2005, widening market differentials caused the difference in our average price received to be approximately $0.90 per Mcf lower than average spot market prices. Assuming a NYMEX commodity price of $7.00 per Mcf of gas for 2008, our differential for the average price received for our gas production is expected to be approximately $0.60 to $0.70 per Mcf below the NYMEX Henry Hub index price, including the impact of our basis hedges. Assuming a NYMEX commodity price of $70.00 per barrel of oil for 2008, we expect the average price received for our oil production to be approximately $1.50 per barrel lower than average spot market prices, as market differentials reduce the average prices received.

Impact of Federal Regulation of Sales of Natural Gas

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.

Oil Price Controls and Transportation Rates

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. The competition for new leases in the Fayetteville Shale play has become especially intense. Due to our significant leasehold acreage position in Arkansas and our long-time presence and reputation in the area, we believe we will continue to be successful in acquiring new leases in Arkansas. 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 generates revenue and operating income through gathering fees associated with the transportation of natural gas to market and through the marketing of our own gas production and third-party natural gas.

Our operating income from this segment was $13.2 million on revenues of $962.0 million in 2007, compared to $4.1 million on revenues of $475.2 million in 2006 and $5.7 million on revenues of $459.9 million in 2005. The increases in revenues are largely attributable to increased volumes marketed, higher purchased gas costs and increased gathering revenues. The decrease in operating income during 2006 was due to increased operating costs and expenses that resulted from increased staffing and other costs associated with our growing gathering activities, and a decrease in the margin generated by our marketing activities caused in part by increased volatility of locational market differentials in our core operating areas.

EBITDA generated by our midstream services segment was $18.8 million in 2007, compared to $5.3 million in 2006 and $6.0 million in 2005. The increase in 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. The decrease in 2006 operating income and EBITDA was primarily due to increased operating costs and expenses that resulted from increased staffing and other costs associated with our growing gathering activities. 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

Our gas gathering subsidiary, DeSoto Gathering Company, L.L.C., or DGC, engages in gathering activities related to the development of our Fayetteville Shale play. In 2007, we invested approximately $107.4 million related to these activities and had gathering revenues of $37.7 million, compared to $48.7 million invested and $7.9 million in revenues in 2006 and $15.8 million invested and $1.0 million in revenues in 2005. DGC is rapidly expanding its network of gathering pipelines and facilities throughout the Fayetteville Shale region. During 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 and 2.3 Bcf of gas in 2005. The increase in volumes gathered in 2007 and 2006 was primarily due to our growing production volumes from the Fayetteville Shale. At the end of 2007, DGC had approximately 556 miles of pipe from the individual wellheads to the transmission lines and compression equipment had been installed at approximately 26 central point gathering facilities in the field. Gathering revenues and expenses for this segment are expected to grow substantially over the next few years as gathering systems for our Fayetteville Shale play are expanded to support the development of our acreage and the increased development activity undertaken by other operators in the area.

Gas Marketing

Our gas marketing subsidiary, SES, allows us to capture downstream opportunities which arise through marketing and transportation activity. Our current marketing operations primarily relate to the marketing of our own gas production and some third-party natural gas. During 2007, we marketed 145.7 Bcf of natural gas, compared to 72.7 Bcf in 2006 and 61.9 Bcf in 2005. Purchases from our E&P subsidiaries accounted for 91% of total volumes marketed in 2007, compared to 86% in 2006 and 78% in 2005.

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 in the Fayetteville Shale play area from several 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.

Natural Gas Distribution

We distribute natural gas to approximately 152,000 customers in northern Arkansas through our subsidiary, AWG. On November 14, 2007, we announced that we had entered into a definitive agreement for the sale of AWG to SourceGas LLC for $224 million plus working capital. Upon the consummation of the pending sale of AWG, we will cease to have any natural gas distribution operations. Subject to regulatory approval, the sale is expected to close approximately mid-year 2008.

Operating income for our Natural Gas Distribution segment was $10.0 million in 2007, compared to $4.5 million in 2006 and $4.9 million in 2005. EBITDA generated by our utility segment was $15.8 million in 2007, compared to $10.5 million in 2006 and $11.7 million in 2005. The increase in 2007 operating income and EBITDA was due to the implementation of a rate increase effective August 1, 2007, colder weather and a decrease in operating costs and expenses. The decrease in 2006 operating income and EBITDA resulted primarily from warmer than normal weather and increased operating costs and expenses, which more than offset a rate increase that became effective October 31, 2005. 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 Purchases and Supply

AWG purchases its system gas supply through a competitive bidding process and directly at the wellhead under long-term contracts with flexible pricing provisions. In 2007, SEECO successfully bid on gas supply packages representing approximately 51% of the requirements for AWG for 2008, compared to approximately 53% for 2007 and 44% for 2006. The contracts awarded to SEECO expire in 2009.

AWG also purchases gas under its gas supply packages from unaffiliated suppliers accessed by interstate pipelines. These purchases are under firm contracts with one-year to two-year terms. The rates charged by most suppliers include demand components to ensure availability of gas supply and a commodity component that is based on monthly indexed market prices. The pipeline transportation rates include demand charges to reserve pipeline capacity and commodity charges based on volumes transported. Less than 4% of the utility's gas purchases are under take-or-pay contracts. AWG believes that it does not have a significant exposure to take-or-pay liabilities resulting from these contracts and expects to be able to continue to satisfactorily manage these contracts.

AWG has a natural gas storage facility connected to its distribution system in northwest Arkansas that it utilizes to help meet its peak seasonal demands. The utility also owns a liquefied natural gas facility and contracts with an interstate pipeline for additional storage capacity to serve its system in the northeastern part of the state. These contracts involve demand charges based on the maximum deliverability, capacity charges based on the maximum storage quantity and charges for the quantities injected and withdrawn.

The utility's rate schedules include a cost of gas rider whereby the projected cost of purchased gas is permitted to be billed to customers. The difference between actual costs of purchased gas and gas costs recovered from customers is deferred each month and is billed or credited, as appropriate, to customers in subsequent months.

AWG enters into hedging activities from time to time with respect to its gas purchases to protect against the inherent price risks of adverse price fluctuations. Our gas distribution segment hedged 4.0 Bcf, 3.1 Bcf, and 4.2 Bcf, respectively, in 2007, 2006, and 2005, which had the effect of increasing its total gas supply costs by $7.5 million, $7.7 million, and $2.4 million, respectively. At December 31, 2007, AWG had 2.0 Bcf of future gas purchases hedged at an average purchase price of $8.61 per Mcf. We refer you to Item 7A of this Form 10-K, "Quantitative and Qualitative Disclosures about Market Risk," and Note 8 to the consolidated financial statements for additional information.

Markets and Customers

At December 31, 2007, AWG provided natural gas to approximately 135,000 residential, 17,000 commercial and 192 industrial customers, while also providing gas transportation services to approximately 123 end-use and off-system customers. Approximately 67% of AWG's customers are located in the Fayetteville-Springdale-Rogers MSA in northwest Arkansas. In recent years, AWG has experienced customer growth of approximately 2% annually. In 2007, customer growth was less than 1% due primarily to a decline in employment growth in the Fayetteville-Springdale-Rogers MSA. Total gas throughput in 2007 was 23.6 Bcf, compared to 21.8 Bcf in 2006 and 23.2 Bcf in 2005. The higher volumes in 2007 were primarily due to colder weather. The lower volumes in both 2006 and 2005 primarily resulted from warmer weather and customer conservation brought about by high gas prices in recent years. Weather in AWG's service territory during 2007 was 9% warmer than normal and 8% colder than in 2006. Weather in 2006 was 17% warmer than normal and 8% warmer than in 2005.

Residential and Commercial. Approximately 88% of the utility's revenues in 2007 were from residential and commercial markets. Residential and commercial customers combined accounted for 58% of total gas throughput for the gas distribution segment in 2007, compared to 56% in 2006 and 57% in 2005. Gas volumes sold to residential customers were 8.6 Bcf in 2007, compared to 7.5 Bcf in 2006 and 8.1 Bcf in 2005. Gas sold to commercial customers totaled 5.1 Bcf in 2007, compared to 4.7 Bcf in 2006 and 5.1 Bcf in 2005. The fluctuations in gas volumes sold to both residential and commercial customers were driven primarily by the effects of weather and customer conservation. The gas heating load is one of the most significant uses of natural gas and is sensitive to outside temperatures. Sales, therefore, vary throughout the year. Profits, however, have become less sensitive to fluctuations in temperature as tariffs implemented contain a weather normalization clause to lessen the impact of revenue increases and decreases that might result from weather variations during the winter heating season.

Industrial and End-use Transportation. Deliveries to AWG's industrial and end-use transportation customers were 9.8 Bcf in 2007, 9.6 Bcf in 2006 and 10.0 Bcf in 2005. No industrial customer accounts for more than 10% of AWG's total throughput. AWG offers a transportation service that allows larger business customers to obtain their own gas supplies directly from other suppliers. Off-system transportation volumes were 0.3 Bcf in 2007, 0.1 Bcf in 2006 and less than 0.1 Bcf in 2005. As of December 31, 2007, a total of 123 customers used the end-use transportation service.

Competition

AWG has historically maintained a price advantage over alternative fuels such as electricity, fuel oil and propane for most applications, enabling it to achieve excellent market penetration levels. However, AWG has experienced a general trend in recent years toward lower rates of usage among its customers, largely as a result of conservation efforts, as well as increasing competition from alternative fuels that has eroded its price advantage. AWG also has the ability to enter into special contracts with larger commercial and industrial customers that contain lower pricing provisions than the approved tariffs. These contracts can be used to meet competition from alternate fuels or threats of bypass and must be approved by the Arkansas Public Service Commission, or the APSC.

Regulation

AWG's rates and operations are regulated by the APSC and AWG must obtain the approval of the APSC in order to increase the rates it charges to its customers. AWG operates through municipal franchises that are perpetual by virtue of state law but may not be exclusive within a geographic area.

In July 2007, the APSC approved a rate increase for our utility segment totaling $5.8 million annually, exclusive of costs to be recovered through the utility's purchase gas adjustment clause. The rate increase became effective for billings rendered on or after August 1, 2007. The APSC order provided for an allowed return on equity of 9.5% and an assumed capital structure of 55% debt and 45% equity. AWG had originally filed the application for a general rate increase of approximately $13.1 million, requesting a capital structure using the modified balance sheet approach inclusive of a 50/50 debt-to-equity ratio and a 10.79% return on equity (ROE). In this rate case, the APSC approved a Trial Billing Determinant Adjustment Mechanism to mitigate the effects of declining use per customer, including lost revenues associated with energy efficiency programs. AWG's last rate increase of $4.6 million annually was effective October 31, 2005, where the APSC approved an allowed ROE of 9.7%. Rate increase requests, which may be filed in the future, will depend on APSC ratemaking policies, customer growth, increases in operating expenses and additional investment in property, plant and equipment.

As the regulatory focus of the natural gas industry has shifted from the federal level to the state level, some utilities across the nation have been required to unbundle residential sales services from transportation services in an effort to promote greater competition. There is no such legislation in Arkansas and no regulatory directives related to natural gas are presently pending. In recent years, there have been efforts by the Arkansas legislature and the APSC concerning the issues of deregulation of the retail sale of electricity and a large-user access program for electric service choice. Legislation adopted in 2001 for deregulation of the retail sale of electricity was repealed in 2003 and no legislative action has been taken regarding implementing a large-user access program.

On January 12, 2006, the APSC initiated a notice of inquiry regarding a rulemaking for developing and implementing energy efficiency programs. Following a collaborative process, the APSC issued energy efficiency rules on January 11, 2007. These rules require all gas and electric utilities, excluding electric cooperatives, to file energy efficiency plans and programs with the APSC. AWG has filed and received approval for its initial energy efficiency plan, and is in the process of implementing Quick Start programs. Comprehensive programs are to be implemented in 2009. AWG is recovering the costs of these programs from its customers.

On December 19, 2006, the APSC issued affiliate transactions rules, which were subsequently revised to address concerns expressed by the parties to the rulemaking proceeding. AWG has filed the Affiliate Transactions Compliance Procedures required by the rules.

Gas distribution revenues in future years will be impacted by APSC policies, customer growth, customer usage and rate increases allowed by the APSC. 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.

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, compared to a pre-tax gain of $1.6 million in 2005.

Historically, our other operations have 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 near our offices in Fayetteville, Arkansas. There were no sales of commercial real estate in 2007 or 2006. As of December 31, 2007, A. W. Realty Company owned an interest in approximately 15 acres of undeveloped real estate near our offices in Fayetteville, Arkansas, and 225 acres in or near Conway, Arkansas, related to our operations in the Fayetteville Shale play.

Other Items

Reconciliation of Non-GAAP Measures

EBITDA is defined as net income 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 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 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, 2007, 2006 and 2005:

2007	**E&P**	**Midstream Services**	**Natural Gas Distribution**	**Other**	**Total**
Net income	$ 211,876	$ 6,933	$ 2,746	$ (381)	**$ 221,174**
Depreciation, depletion and amortization	282,387	5,527	6,423	163	**294,500**
Net interest expense	16,926	2,006	4,941	-	**23,873**
Provision for income taxes	129,315	4,294	1,672	574	**135,855**
EBITDA	$ 640,504	$ 18,760	$ 15,782	$ 356	**$ 675,402**
2006					
Net income	$ 151,157	$ 2,976	$ 2,190	$ 6,313	**$ 162,636**
Depreciation, depletion and amortization	143,500	1,773	6,428	94	**151,795**
Net interest expense	508	-	171	-	**679**
Provision for income taxes	91,276	554	1,698	5,871	**99,399**
EBITDA	$ 386,441	$ 5,303	$ 10,487	$ 12,278	**$ 414,509**
2005					
Net income	$ 144,349	$ 2,962	$ 203	$ 246	**$ 147,760**
Depreciation, depletion and amortization	89,229	303	7,010	99	**96,641**
Net interest expense	8,416	1,054	4,429	1,141	**15,040**
Provision for income taxes	83,921	1,668	11	831	**86,431**
EBITDA	$ 325,915	$ 5,987	$ 11,653	$ 2,317	**$ 345,872**

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 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.

Employees

At December 31, 2007, we had 1,521 total employees, including 383 employed by our drilling subsidiary and 373 employed by AWG. None of our employees were covered by a collective bargaining agreement at year-end 2007. 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.

"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.

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

"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.

"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 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 information.

"Exploratory 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, see also "Downspacing."

"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 Btu's.

"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.

"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, which is available at the SEC's website, http://www.sec.gov/about/forms/regs-x.pdf, page 41.

"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, which is available at the SEC's website, http://www.sec.gov/about/forms/regs-x.pdf, page 41.

"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, which is available at the SEC's website, http://www.sec.gov/about/forms/regs-x.pdf, page 41.

"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.

"Recomplete" This term refers to the technique of drilling a separate well-bore from all existing casing in order to reach the same reservoir, or redrilling the same well-bore to reach a new reservoir after production from the original reservoir has been abandoned.

"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.

"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.

"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 are not necessarily exhaustive and investors are encouraged to perform their own investigation with respect to us and 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 Operations — 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;
- competition from other sources of energy; and
- economic, political and regulatory developments.

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 quarterly 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.

Natural gas and oil prices have recently been at or near their highest historical levels. A substantial 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:

- our cash flow would be reduced, decreasing funds available for capital investments employed to replace reserves or increase production;
- certain reserves would no longer be economic to produce, leading to both lower proved reserves and cash flow; and
- 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, 2007, 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, particularly as a result of our drilling program. Our planned capital investments for 2008 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, 2007, 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, we may not be able to borrow under it to fund our capital investments. We also cannot be certain that other additional financing will be available to us on acceptable terms or at all. In the event additional capital resources are unavailable, we may curtail our drilling, development and other activities or be forced to sell some of our assets on an untimely or unfavorable basis. Any such curtailment or sale could have a material adverse effect on our results and future operations.

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

Some of our working interest owners may have difficulties obtaining the capital needed to finance their activities, or may believe that estimated drilling and completion costs are excessive. As a result, these working interest owners may 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 these 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 81% 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 81% present value as of December 31, 2007 accounted for approximately 85% of our total proved reserves and approximately 90% 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 the president of our E&P subsidiaries. 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:

- expected reservoir characteristics based on geological, geophysical and engineering assessments;
- future production rates based on historical performance and expected future operating and investment activities;
- future oil and gas prices and quality and locational differentials; and
- 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 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 offset by an upward performance revision in our Fayetteville Shale properties. In 2005, our reserves were revised downward by 31.7 Bcfe, primarily due to unexpected declines associated with our Gulf Coast properties and minor changes to decline rates for our wells at the Overton Field. 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, 2007, approximately 36% 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, 2007, we had total long-term indebtedness of $977.6 million, including borrowings of $842.2 million 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. At February 22, 2008, we had total long-term indebtedness of $1,063.6 million, including borrowings of $328.2 million under of 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 2008. 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 the indenture 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 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. Except to the extent that 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, 2007, we had drilled and completed 478 wells relating to our Fayetteville Shale play. At year-end 2007, approximately 18% 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:

- our ability to determine the most effective and economic fracture stimulation for the Fayetteville Shale formation;
- material changes in natural gas prices;
- changes in the estimates of costs to drill or complete wells;
- the extent of our success in drilling and completing horizontal wells;
- our ability to reduce our exposure to costs and drilling risks;
- the costs and availability of drilling equipment;
- success or failure of wells drilled in similar formations or which would use the same production facilities;
- receipt of additional seismic or other geologic data or reprocessing of existing data;
- the extent to which we are able to effectively operate our own drillings rigs; or
- availability and cost of capital.

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.

We may have difficulty drilling all of the wells that are necessary to hold our Fayetteville Shale acreage before the initial lease terms expire, which could result in the loss of certain leasehold rights.

Approximately 259,000 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. However, current rules are subject to change and could impair our ability to drill or maintain our acreage position. To the extent that any field rules prevent us from successfully drilling wells in certain areas, we may not be able to drill the wells required to maintain our leasehold rights for certain of our Fayetteville Shale acreage.

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

As of December 31, 2007, we had invested approximately $161 million in our gas gathering operations and we intend to invest approximately $101 million in 2008. Our gas gathering business will largely rely on gas sourced in our Fayetteville Shale play area in Arkansas. In addition, we have signed a precedent agreement committing us to a portion of the transportation fees related to the Fayetteville and Greenville laterals being built to service the Fayetteville Shale play area by Texas Gas Transmission, LLC, a subsidiary of Boardwalk Pipeline Partners, LP, or TGT. Our gas gathering subsidiary has also entered into multiple 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.

An increase in the Arkansas severance tax on natural gas could adversely impact the economic feasibility of the Fayetteville Shale play and our results of operations.

The State of Arkansas currently levies severance taxes on a broad range of minerals and other natural resources, including natural gas and oil. Currently, the Arkansas severance tax on natural gas is equal to 0.3 cents per 1000 cubic feet. There are presently efforts being undertaken in Arkansas within and without the legislature to modify the severance tax on natural gas so that it is based on a percentage of the market value of the natural gas at the time and point of severance, and to have that percentage be as much as 7%. A 1934 amendment to the Arkansas constitution requires a three-fourths vote by both the House and Senate to raise the severance tax. However, if the severance tax increase is proposed through a ballot initiative, a simple majority of the Arkansas voters can approve the proposed increase. The attorney general of Arkansas recently approved the wording of a ballot initiative that would raise the natural gas severance tax in Arkansas to 7% of the market value of the gas at the time of severance. The governor of Arkansas has publicly stated his support for an increase in the natural gas severance tax to levels comparable to those in Texas and Oklahoma and indicated that, if the natural gas production industry and the legislature do not agree to raise the severance tax, he may introduce a ballot initiative in 2008. The deadline for submitting the petition for proposed initiated acts to the secretary of state's office is July 7, 2008, and the petition must contain 61,974 signatures from registered Arkansas voters in order to be placed on the general election ballot. If enacted, an increase in the severance tax on natural gas could impact the economic feasibility of our Fayetteville Shale play and our results of operations.

Our exploration, development and drilling efforts and our operations 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, transmission and distribution 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 and the drilling of natural gas and oil wells, including encountering well blowouts, cratering and explosions, pipe failure, fires, formations with abnormal pressures, uncontrollable flows of oil, natural gas, brine or well fluids, release of contaminants into the environment and other environmental hazards and risks.

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, 2007, approximately 10% of our gas and oil properties, based on PV-10 value, are 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 intend to use the Fayetteville and Greenville laterals being built by TGT to sell our production. The laterals are supposed to be available in January 2009. A delay in the commencement of operations of the Fayetteville and Greenville laterals, the unavailability of 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.

Shortages of oilfield equipment, services 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. 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; however, we are still dependent on third-party drilling companies. We also have limited experience in operating drilling rigs.

We have made significant investments in our drilling rig operations, including commitments to lease 15 drilling rigs and related equipment and have hired, as of December 31, 2007, 383 employees for our drilling subsidiary, DeSoto Drilling, Inc. The 15 drilling rigs will not be sufficient to meet the needs of our drilling program and we will still be dependent upon third-party rig providers in order to execute our drilling program in 2008 and beyond, even if we make additional investments. There can be no assurance that our drilling rig operations will not 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.

In addition, 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.

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, 2007, we had hedges on approximately 70% of our targeted 2008 natural gas production. Our price risk management activities increased revenues by $70.7 million in 2007 and $8.7 million in 2006, but decreased revenues by $77.2 million in 2005. 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:

- our production is less than expected;
- there is a widening of price differentials between delivery points for our production and the delivery point assumed in the hedge arrangement;
- the counterparties to our futures contracts fail to perform the contracts; or
- a sudden, unexpected event materially impacts natural gas or oil prices.

Finally, future market price volatility could create significant changes to the hedge positions recorded on our financial statements. We refer 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 6 and 7 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.”

Leasehold acreage as of December 31, 2007:

	Undeveloped		Developed	
	Gross	**Net**	**Gross**	**Net**
Conventional Arkoma[1]	390,362	299,599	298,270	192,192
Fayetteville Shale Play[2]	930,560	637,560	206,720	143,740
East Texas[3]	110,617	91,148	39,477	27,756
Permian Basin	16,291	8,944	93,177	28,456
Gulf Coast	12,369	5,795	10,809	3,042
New Ventures[4]	163,196	156,465	14,715	11,771
	1,623,395	1,199,511	663,168	406,957

(1) 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 in the table above.

(2) 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 16,561 net acres in 2008, 96,601 net acres in 2009 and 145,722 net acres in 2010.

(3) Assuming we do not drill successful wells to develop the acreage and do not extend the leases in our undeveloped acreage in the Angelina River Trend and Jebel areas in East Texas, leasehold expiring over the next three years will be 7,737 net acres in 2008, 33,274 net acres in 2009 and 4,474 acres in 2010.

(4) Includes New Ventures opportunities such as the Marcellus Shale play in Pennsylvania.

Producing wells as of December 31, 2007:

	Gas		Oil		Total		Gross Wells
	Gross	Net	Gross	Net	Gross	Net	Operated
Conventional Arkoma.........	1,098	550	-	-	1,098	550	513
Fayetteville Shale Play........	497	377	-	-	497	377	429
East Texas...........................	464	390	2	2	466	392	440
Permian Basin.....................	150	25	256	113	406	138	52
Gulf Coast...........................	30	12	4	-	34	12	3
New Ventures......................	14	9	-	-	14	9	11
	2,253	1,363	262	115	2,515	1,478	1,448

Wells drilled during the year:

Exploratory

	Productive Wells		Dry Holes		Total	
Year	Gross	Net	Gross	Net	Gross	Net
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
2005............................	15.0	13.4	2.0	1.8	17.0	15.2

Development

	Productive Wells		Dry Holes		Total	
Year	Gross	Net	Gross	Net	Gross	Net
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
2005............................	182.0	141.7	6.0	3.3	188.0	145.0

Wells in progress as of December 31, 2007:

	Gross	Net
Exploratory.....................................	48.0	35.5
Development..................................	149.0	100.8
Total..	197.0	136.3

During 2007, we were required to file Form 23, “Annual Survey of Domestic Oil and Gas Reserves,” with the Department of Energy. The basis for reporting reserves on Form 23 is not comparable to the reserve data included in Note 7 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, 2007, our Midstream Services segment had 556 miles of pipe in its gathering systems located in Arkansas.

The following table provides information concerning miles of pipe of our Natural Gas Distribution segment as of December 31, 2007. For a further description of AWG's properties, we refer you to "Business — Natural Gas Distribution."

	Total
Gathering	395
Transmission	1,038
Distribution	4,360
	5,793

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.

EXECUTIVE OFFICERS OF THE REGISTRANT

Name	**Officer Position**	**Age**	**Years Served as Officer**
Harold M. Korell	President, Chief Executive Officer and Chairman of the Board	63	11
Greg D. Kerley	Executive Vice President and Chief Financial Officer	52	18
Richard F. Lane	Executive Vice President, and President, Southwestern Energy Production Company and SEECO, Inc.	50	9
Mark K. Boling	Executive Vice President, General Counsel and Secretary	50	6
Gene A. Hammons	President, Southwestern Midstream Services Company	62	3

Mr. Korell was elected as Chairman of the Board in May 2002 and has served as Chief Executive Officer since January 1999 and President since October 1998. 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. 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.

Mr. Lane was appointed to Executive Vice President of Southwestern Energy Company and promoted to President, SEECO, Inc. and Southwestern Energy Production Company in December 2005. He was appointed to the position of Executive Vice President, SEECO, Inc. and Southwestern Energy Production Company in December 2001. Previously, he served as Senior Vice President from February 2001 and Vice President-Exploration from February 1999. Mr. Lane joined us in February 1998 as Manager-Exploration. From 1993 to 1998, he was employed by American Exploration Company where he was most recently Offshore Exploration Manager. Previously, he held various managerial and geological positions at FINA, Inc. and Tenneco Oil Company.

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 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 the named executive officers or between any of them and our directors.

PART II

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

Our common stock is traded on the New York Stock Exchange under the symbol "SWN." On February 22, 2008, the closing price of our stock was $61.72 and we had 2,201 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 splits effected in June 2005 and November 2005.

	Range of Market Prices					
Quarter Ended	**2007**		2006		2005	
March 31	**$41.28**	**$32.87**	$43.42	$29.33	$15.47	$11.22
June 30	**$50.18**	**$41.38**	$39.97	$24.80	$23.49	$14.20
September 30	**$45.70**	**$35.99**	$37.47	$27.95	$37.18	$24.78
December 31	**$56.53**	**$42.51**	$42.59	$27.86	$41.15	$31.30

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

Issuer Purchases of Equity Securities

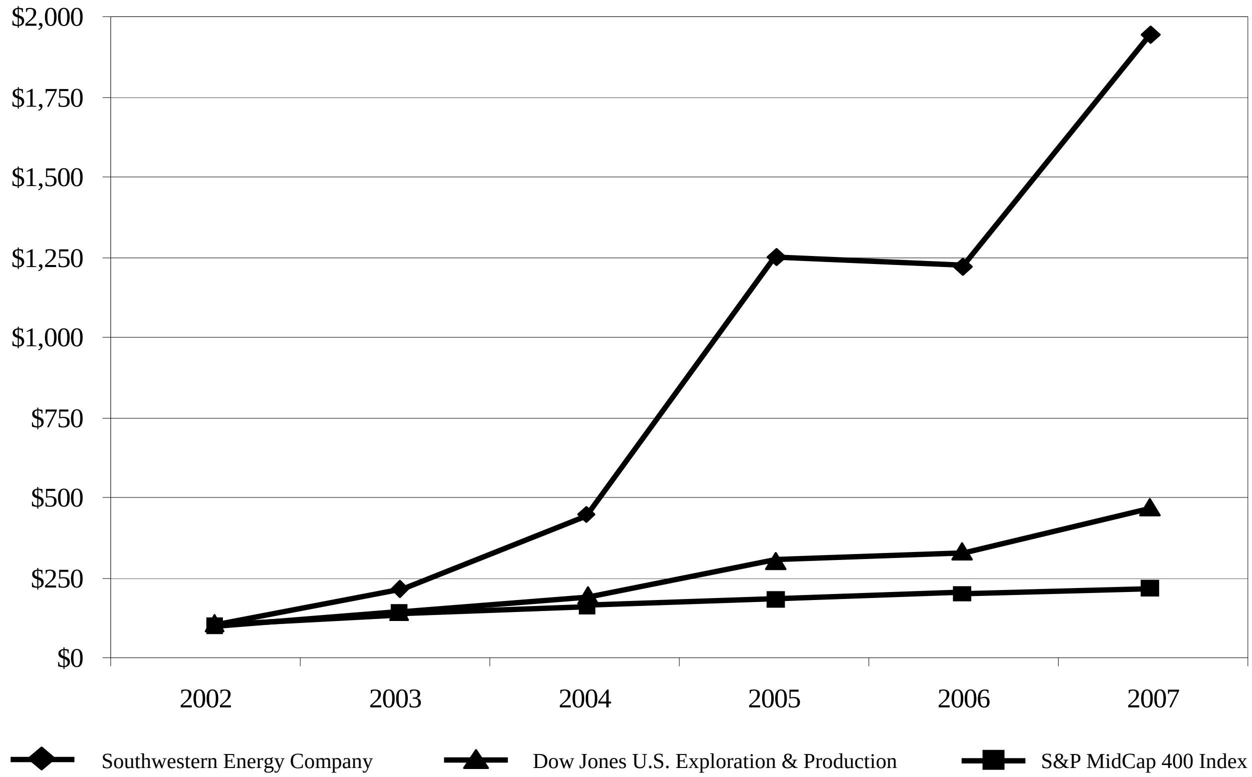
We did not repurchase any shares of our equity securities during 2007.

Recent Sales of Unregistered Equity Securities

We did not sell any unregistered equity securities during 2007.

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 and the Dow Jones U.S. Exploration & Production Index (previously known as the Dow Jones Oil — Secondary Index). The chart assumes that the value of the investment in our common stock and each index was $100 at December 31, 2002, and that all dividends were reinvested. The stock performance shown on the graph below is not indicative of future price performance.



	12/31/02	12/31/03	12/31/04	12/31/05	12/31/06	12/31/07
Southwestern Energy Company	100	209	443	1,256	1,224	1,947
Dow Jones U.S. Exploration & Production	100	131	186	307	324	465
S&P MidCap 400 Index	100	136	158	178	196	212

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, 2007. This information and the notes thereto are derived from our financial statements. We refer you to "Management's Discussion and Analysis of Financial Condition and Results of Operations" and "Financial Statements and Supplementary Data."

	2007	2006	2005	2004	2003
	(in thousands except share, per share, stockholder data and percentages)				
Financial Review					
Operating revenues					
Exploration and production	**$ 795,944**	$ 491,545	$ 403,234	$ 286,924	$ 176,245
Midstream services	**961,994**	475,207	459,890	314,977	201,976
Gas distribution and other	**174,914**	172,655	179,375	158,698	140,829
Intersegment revenues	**(677,721)**	(376,295)	(366,170)	(283,462)	(191,649)
	1,255,131	763,112	676,329	477,137	327,401
Operating costs and expenses					
Gas purchases – midstream services	**306,336**	128,387	124,730	60,804	39,428
Gas purchases – gas distribution	**85,445**	79,363	82,689	64,311	52,585
Operating and general	**166,095**	132,691	101,500	78,231	70,479
Depreciation, depletion and amortization	**293,914**	151,290	96,211	73,674	55,948
Taxes, other than income taxes	**21,875**	25,109	25,279	17,830	11,619
	873,665	516,840	430,409	294,850	230,059
Operating income	**381,466**	246,272	245,920	182,287	97,342
Interest expense, net	**(23,873)**	(679)	(15,040)	(16,992)	(17,311)
Other income (expense)	**(219)**	17,079	4,784	(362)	797
Minority interest in partnership	**(345)**	(637)	(1,473)	(1,579)	(2,180)
Income before income taxes and accounting change	**357,029**	262,035	234,191	163,354	78,648
Income taxes					
Current	**—**	—	—	—	—
Deferred	**135,855**	99,399	86,431	59,778	28,896
	135,855	99,399	86,431	59,778	28,896
Income before accounting change	**221,174**	162,636	147,760	103,576	49,752
Cumulative effect of adoption of accounting principle	**—**	—	—	—	(855)
Net income	**$ 221,174**	$ 162,636	$ 147,760	$ 103,576	$ 48,897
Return on equity	**13.4%**	11.3%	13.3%	23.1%	14.3%
Net cash provided by operating activities	**$ 622,735**	$ 429,937	$ 304,482	$ 237,897	$ 109,099
Net cash used in investing activities	**$ (1,513,497)**	$ (630,006)	$ (452,918)	$ (285,448)	$ (161,656)
Net cash provided by financing activities	**$ 849,667**	$ 19,291	$ 370,906	$ 47,509	$ 52,144
Common Stock Statistics [(1)]					
Earnings per share:					
Basic	**$ 1.31**	$ 0.97	$ 0.98	$ 0.72	$ 0.37
Diluted	**$ 1.27**	$ 0.95	$ 0.95	$ 0.70	$ 0.36
Cash dividends declared and paid per share	**$ —**	$ —	$ —	$ —	$ —
Book value per average diluted share	**$ 9.48**	$ 8.38	$ 7.10	$ 3.03	$ 2.49
Market price at year-end	**$ 55.72**	$ 35.05	$ 35.94	$ 12.67	$ 5.98
Number of stockholders of record at year-end	**2,275**	2,412	2,126	2,022	2,026
Average diluted shares outstanding	**173,721,330**	171,287,750	156,309,039	147,851,088	136,951,736

[(1)] 2004 and 2003 restated to reflect two-for-one stock splits effected in June and November 2005.

	2007	2006	2005	2004	2003
Capitalization (in thousands)					
Total debt	**$ 978,800**	$ 137,800	$ 100,000	$ 325,000	$ 278,800
Common stockholders' equity	**1,646,500**	1,434,643	1,110,304	447,677	341,561
Total capitalization	**$ 2,625,300**	$ 1,572,443	$ 1,210,304	$ 772,677	$ 620,361
Total assets	**$ 3,622,716**	$ 2,379,069	$ 1,868,524	$ 1,146,144	$ 890,710
Capitalization ratios:					
Debt	**37.3%**	8.8%	8.3%	42.1%	44.9%
Equity	**62.7%**	91.2%	91.7%	57.9%	55.1%
Capital Investments (in millions) [1]					
Exploration and production					
Exploration and development	**$ 1,375.2**	$ 767.4	$ 416.2	$ 282.0	$ 170.9
Drilling rigs and related equipment [2]	**4.5**	93.6	35.1	—	—
	1,379.7	861.0	451.3	282.0	170.9
Midstream services	**107.4**	48.7	15.8	—	—
Gas distribution	**11.4**	11.2	10.9	7.3	8.2
Other	**4.6**	21.5	5.1	5.7	1.1
	$ 1,503.1	$ 942.4	$ 483.1	$ 295.0	$ 180.2
Exploration and Production					
Natural gas:					
Production, Bcf	**109.9**	68.1	56.8	50.4	38.0
Average price per Mcf, including hedges	**$ 6.80**	$ 6.55	$ 6.51	$ 5.21	$ 4.20
Average price per Mcf, excluding hedges	**$ 6.16**	$ 6.37	$ 7.73	$ 5.80	$ 5.15
Oil:					
Production, MBbls	**614**	698	705	618	531
Average price per barrel, including hedges	**$ 69.12**	$ 58.36	$ 42.62	$ 31.47	$ 26.72
Average price per barrel, excluding hedges	**$ 69.12**	$ 63.17	$ 54.37	$ 40.55	$ 29.66
Total gas and oil production, Bcfe	**113.6**	72.3	61.0	54.1	41.2
Lease operating expenses per Mcfe	**$ .73**	$ .66	$ .48	$ .38	$ .39
General and administrative expenses per Mcfe	**$ .48**	$ .58	$ .46	$ .36	$ .41
Taxes other than income taxes per Mcfe	**$ .16**	$ .30	$ .37	$ .28	$ .22
Proved reserves at year-end:					
Natural gas, Bcf	**1,396.9**	978.9	772.3	594.5	457.0
Oil, MBbls	**8,912**	7,898	9,079	8,508	7,675
Total reserves, Bcfe	**1,450.3**	1,026.3	826.8	645.5	503.1
Midstream Services					
Gas volumes marketed	**145.7**	72.7	61.9	57.0	42.7
Gas volumes gathered	**78.7**	14.6	2.3	—	—
Natural Gas Distribution					
Sales and transportation volumes, Bcf	**23.6**	21.8	23.2	24.0	24.7
Off-system transportation, Bcf [3]	**0.3**	0.1	—	1.0	0.3
Total volumes delivered	**23.9**	21.9	23.2	25.0	25.0
Customers at year-end:					
Residential	**134,616**	133,679	130,654	127,622	124,776
Commercial	**17,180**	17,151	16,996	16,815	16,623
Industrial	**192**	173	170	175	174
	151,988	151,003	147,820	144,612	141,573
Degree days	**3,699**	3,413	3,744	3,678	3,969
Percent of normal	**91%**	83%	91%	90%	99%

(1) Capital investments include a reduction of $20.6 million for 2007 and increases of $88.9 million, $28.1 million, $3.9 million and $12.0 million for 2006, 2005, 2004 and 2003, 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) 2005 off-system transportation volumes were less than 0.1 Bcf.

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 "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 related notes included elsewhere 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 principally are located in Arkansas, Oklahoma 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 operate principally in three segments: Exploration and Production (E&P), Midstream Services and Natural Gas Distribution. Upon the consummation of the pending sale of our utility subsidiary, Arkansas Western Gas Company, we will cease to have any natural gas distribution operations. We refer you to Note 1 to the consolidated financial statements for additional information. The transaction is subject to certain closing conditions and regulatory approvals and is expected to close approximately mid-year 2008. Pursuant to Statement of Financial Accounting Standards No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets" (FAS 144), the assets and liabilities of Arkansas Western Gas Company ("AWG") have been reclassified as "held for sale" in our December 31, 2007 and 2006 balance sheets. However, the results of operations for AWG continue to be 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. 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 determines the pricing. In addition, the price we realize for our gas production is affected by our hedging activities as well as locational differences in market prices. 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 2007, our gas and oil production increased 57% to 113.6 Bcfe, and in 2006 our production increased 19% to 72.3 Bcfe. The increases in production in both 2007 and 2006 primarily resulted from increases in production from our Fayetteville Shale play in Arkansas. We are targeting 2008 gas and oil production of 148 to 152 Bcfe, an increase of 30% to 35% over our 2007 production. Our year-end reserves grew 41% in 2007 to 1,450.3 Bcfe, up from 1,026.3 Bcfe at the end of 2006. These increases were also primarily fueled by the continued development of our Fayetteville Shale play.

We reported net income of $221.2 million in 2007, or $1.27 per share on a fully diluted basis, up 36% from the prior year. Net income in 2006 increased approximately 10% to $162.6 million, or $0.95 per share, compared to 2005. The increase in net income in 2007 was a result of increased production volumes in our E&P segment, partially offset by increased operating costs and expenses and increased interest expense. The increase in net income in 2006 was a result of increased production volumes in our E&P segment, a gain on the sale of our NOARK investment and decreased interest expense, partially offset by increased operating costs and expenses. Our cash flow from operating activities increased 45% to $622.7 million in 2007 and 41% to $429.9 million in 2006, primarily due to increases in net income and adjustments to net income for non-cash expenses.

Operating income for our E&P segment was $358.1 million in 2007, $237.3 million in 2006 and $234.8 million in 2005. Operating income for our E&P segment increased in 2007 due to increased production volumes, partially offset by increased operating costs and expenses. Operating income for our Midstream Services segment was $13.2 million in 2007, compared to $4.1 million in 2006 and $5.7 million in 2005. Operating income for our Midstream Services segment increased in 2007 due to an increase in gathering revenues related to our Fayetteville Shale play and an increase in the margin generated from marketing of natural gas, partially offset by increased operating costs and expenses. Operating income for our Midstream Services segment decreased in 2006 as increased gathering revenues were more than offset by increased operating costs and expenses and a decrease in the margin generated by our marketing activities. Operating income for our Natural Gas Distribution segment was $10.0 million in 2007, compared to $4.5 million in 2006 and $4.9 million in 2005. The increase in operating income for our Natural Gas Distribution segment in 2007 resulted from a rate increase implemented in August 2007, from colder weather and a decrease in operating costs and expenses. The decrease in operating income for our Natural Gas Distribution segment in 2006 resulted primarily from warmer weather and increased operating costs and expenses.

Our capital investments totaled approximately $1.5 billion in 2007, up from $942.4 million in the prior year. We invested $1.38 billion in our E&P segment in 2007, compared to $861.0 million in 2006 (including $93.6 million invested in drilling rigs) and $451.3 million in 2005 (including $35.1 million invested in drilling rigs). Funds for our 2007 capital investments were provided by borrowings under our revolving credit facility, cash flow from operations and cash proceeds from a December 2006 drilling rig sale and leaseback transaction. As a result of our increased borrowings, our total debt-to-capitalization ratio increased to 37% at December 31, 2007, up from 9% at December 31, 2006.

For 2008, our planned capital investments are $1.46 billion, approximately equal to the level of our 2007 capital investments, and include $1.33 billion for our E&P segment, $101 million for our Midstream Services segment and $25 million for other corporate purposes (including improvements to the utility system in advance of the pending sale). The $1.33 billion of E&P investments includes approximately $1.0 billion for the development of our Fayetteville Shale play and approximately 82% of our 2008 E&P capital is allocated to drilling. In addition to the planned investments in the Fayetteville Shale play, our E&P investments in 2008 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 2008 to be funded from internally-generated cash flow, borrowings under our revolving credit facility, funds raised in the debt markets and proceeds from the sale of our utility and the anticipated divestiture of certain E&P assets.

RESULTS OF OPERATIONS

Exploration and Production

	Year Ended December 31,		
	2007	2006	2005
Revenues (in thousands)	**$795,944**	$491,545	$403,234
Operating income (in thousands)	**$358,079**	$237,307	$234,759
Gas production (Bcf)	**109.9**	68.1	56.8
Oil production (MBbls)	**614**	698	705
Total production (Bcfe)	**113.6**	72.3	61.0
Average gas price per Mcf, including hedges	**$ 6.80**	$ 6.55	$ 6.51
Average gas price per Mcf, excluding hedges	**$ 6.16**	$ 6.37	$ 7.73
Average oil price per Bbl, including hedges	**$ 69.12**	$ 58.36	$ 42.62
Average oil price per Bbl, excluding hedges	**$ 69.12**	$ 63.17	$ 54.37
Average unit costs per Mcfe:			
Lease operating expenses	**$ 0.73**	$ 0.66	$ 0.48
General & administrative expenses	**$ 0.48**	$ 0.58	$ 0.46
Taxes other than income taxes	**$ 0.16**	$ 0.30	$ 0.37
Full cost pool amortization	**$ 2.41**	$ 1.90	$ 1.42

Revenues, Operating Income and Production

Revenues. Revenues for our E&P segment increased 62% in 2007 to $795.9 million primarily due to a 57% increase in total gas and oil production. Revenues increased 22% in 2006 to $491.5 million, primarily due to a 19% increase in our production volumes. We expect our production volumes to continue to increase primarily due to the development of our Fayetteville Shale play in Arkansas. Gas and oil prices are difficult to predict and are subject to wide price fluctuations. As of February 22, 2008, we have hedged 118.0 Bcf, 104.0 Bcf and 18.0 Bcf of our 2008, 2009 and 2010 gas production, respectively, in order to limit our exposure to price fluctuations. Revenues for 2007, 2006 and 2005 also include pre-tax gains of $6.4 million, $4.0 million and $3.1 million, respectively, related to the sale of gas-in-storage inventory.

Operating Income. Operating income from our E&P segment was $358.1 million in 2007, an increase of 51% from $237.3 million in 2006, as the increase in our revenues was partially offset by increased operating costs and expenses. Operating income was up 1% in 2006 compared to 2005 as the increase in revenues was largely offset by increased operating costs and expenses.

Production. Gas and oil production was up approximately 57% to 113.6 Bcfe in 2007 and up 19% to 72.3 Bcfe in 2006, compared to prior periods. The increase in 2007 was primarily the result of a 41.7 Bcf increase in production from our Fayetteville Shale play. The increase in 2006 was the result of a 10.0 Bcf increase in production from our Fayetteville Shale play and a 4.0 Bcf increase in our East Texas production, partially offset by declines in production from our Permian and Gulf Coast properties. Our net production from the Fayetteville Shale play was 53.5 Bcf in 2007, up from 11.8 Bcf in 2006 and 1.8 Bcf in 2005.

Gas sales to unaffiliated purchasers were up 66% to 105.1 Bcf in 2007 and up 23% to 63.4 Bcf in 2006, 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 increased slightly to 4.8 Bcf in 2007 and decreased 7% to 4.7 Bcf in 2006. Future increases in demand for our gas production are expected to 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 of both affiliated and unaffiliated customers for our production.

We are targeting 2008 gas and oil production of 148.0 to 152.0 Bcfe, an increase of 30% to 35% over our 2007 production. Our 2008 production volumes could also be impacted by the anticipated sale of certain E&P assets. Based on early production histories and modeling and assuming continued positive results, approximately 90.0 to 95.0 Bcf of our 2008 targeted gas production is projected to come from our activities in the Fayetteville Shale play. Although we expect production volumes in 2008 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 9 to the consolidated financial statements for additional discussion). The average price realized for our gas production, including the effects of hedges, increased to $6.80 per Mcf in 2007 and increased slightly to $6.55 per Mcf in 2006. The changes in the average price realized primarily reflect changes in average annual spot market prices and the effects of our price hedging activities. Our hedging activities increased the average gas price $0.64 per Mcf in 2007, compared to an increase of $0.18 per Mcf in 2006 and a reduction of $1.22 per Mcf in 2005. 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 2007, 2006 and 2005, widening market differentials caused the difference in our average price received for our gas production to be approximately $0.70 to $0.90 per Mcf lower than spot market prices. Assuming a NYMEX commodity price for 2008 of $7.00 per Mcf of gas, our differential for the average price received for our gas production is expected to be approximately $0.60 to $0.70 per Mcf below the NYMEX Henry Hub index price, including the impact of our basis hedges. As of December 31, 2007, we have financially protected future gas production volumes of 91.3 Bcf in 2008 and 3.6 Bcf in 2009 from the impact of widening basis differentials through our hedging activities and sales arrangements.

In addition to the basis hedges discussed above, at December 31, 2007, we had NYMEX commodity price hedges in place on 102.0 Bcf of 2008 and 79.0 Bcf of 2009 expected future gas production. Subsequent to December 31, 2007 and prior to February 22, 2008, we hedged 16.0 Bcf of 2008, 17.0 Bcf of 2009 and 16.0 Bcf of 2010 gas production under fixed price swaps with average prices of $8.99, $8.53 and $8.55 per Mcf, respectively. In addition, we hedged 8.0 Bcf of 2009 and 2.0 Bcf of 2010 gas production using costless collars. The collars relating to 2009 production have a weighted average floor and ceiling price of $8.00 and $10.05 per Mcf, respectively; and the collars relating to 2010 production have a weighted average floor and ceiling price of $8.50 and $10.20 per Mcf, respectively. We have also basis protected an additional 2.1 Bcf of 2008 gas production with an average differential price of $0.26 below NYMEX spot rates. As of February 22, 2008, we have hedged approximately 80% of our 2008 anticipated gas production.

We realized an average price of $69.12 per barrel for our oil production for the year ended December 31, 2007, up approximately 18% from the prior year. We did not hedge any of our 2007 oil production. The 2006 realized average price of $58.36 per barrel, including the effects of hedges, was up 37% from 2005. The average prices we received for our oil production in 2006 and 2005 were reduced by $4.81 and $11.75 per barrel, respectively, due to the effects of our hedging activities. Assuming a NYMEX commodity price of $70.00 per barrel of oil for 2008, we expect the average price received for our oil production during 2008 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 $0.73 in 2007, compared to $0.66 in 2006 and $0.48 in 2005. Lease operating expenses per unit of production increased in 2007 and 2006 due primarily to increases in our gathering and compression costs related to our operations in the Fayetteville Shale play. We expect our per unit operating cost for this segment to range between $0.85 and $0.90 per Mcfe in 2008 primarily due to increased production volumes from the Fayetteville Shale play.

General and administrative expenses for the E&P segment were $0.48 per Mcfe in 2007, down from $0.58 per Mcfe in 2006 and up from $0.46 per Mcfe in 2005. The decrease in general and administrative costs per Mcfe in 2007 as compared to 2006 was due to the effects of our increased production volumes. In total, general and administrative expenses for the E&P segment were $54.8 million in 2007, $41.9 million in 2006 and $28.2 million in 2005. The increases in total general and administrative costs since 2005 were due primarily to increased payroll and related costs associated with the expansion of our E&P operations due to the Fayetteville Shale play and to increased incentive compensation costs. We added 243 new employees during 2007, most of which were hired in our E&P segment, compared to 494 employees added in 2006. We expect our cost per unit for general and administrative expenses to continue to decline in 2008 and range between $0.42 and $0.47 per Mcfe. The expected decrease in per unit costs in 2008 is due to increased production volumes from our Fayetteville Shale play and a reduced rate of expansion in our E&P workforce. 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 $2.41 per Mcfe for 2007, $1.90 per Mcfe for 2006 and $1.42 per Mcfe for 2005. The amortization rate is impacted by 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. Unevaluated costs excluded from amortization were $372.4 million at the end of 2007, compared to $166.8 million at the end of 2006 and $122.3 million at the end of 2005. The increase in unevaluated costs since December 31, 2005, resulted primarily from an increase in our undeveloped leasehold acreage and seismic costs for our Fayetteville Shale play and the related increased drilling activity.

Taxes other than income taxes per Mcfe were $0.16 in 2007, $0.30 in 2006 and $0.37 in 2005, and vary from year to year due to changes in severance and ad valorem taxes that primarily result from the mix of our production volumes and fluctuations in commodity prices. Additionally, we accrued $4.9 million in 2007 for severance tax refunds related to our East Texas production.

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 would 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 period but prior to the release of periodic reports may be utilized to calculate the ceiling value of reserves. At December 31, 2007, 2006 and 2005, our unamortized costs of natural gas and oil properties did not exceed this ceiling amount. 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, adjusted for market differentials. Cash flow hedges of gas production in place at December 31, 2007 increased the calculated ceiling value by approximately $163 million (net of tax). We had approximately 181.0 Bcf of future gas production hedged at December 31, 2007. 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, and at December 31, 2005, the ceiling value of our reserves was calculated based upon quoted market prices of $10.08 per Mcf for Henry Hub gas and $61.04 per barrel for West Texas Intermediate oil. Decreases in market prices from December 31, 2007 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 due to low inflation rates. However, since 2001, as commodity prices have 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 experienced decreases in certain costs and third-party services primarily due to increased vendor competition in our Fayetteville Shale operating area.

Midstream Services

	Year Ended December 31,		
	2007	2006	2005
	($ in millions, except volumes)		
Revenues – marketing	**$ 924.3**	$ 467.3	$ 458.9
Revenues – gathering	**$ 37.7**	$ 7.9	$ 1.0
Gas purchases – marketing	**$ 915.1**	$ 458.9	$ 451.1
Operating costs and expenses	**$ 33.7**	$ 12.2	$ 3.1
Operating income	**$ 13.2**	$ 4.1	$ 5.7
Gas volumes marketed (Bcf)	**145.7**	72.7	61.9
Gas volumes gathered (Bcf)	**78.7**	14.6	2.3

Revenues from our Midstream Services segment were up 102% in 2007 and up 3% in 2006, as compared to prior years. The increases in revenues in 2007 and 2006 resulted from increases in volumes marketed and increased gathering revenues, primarily relating to the Fayetteville Shale play. Increases and decreases in marketing revenues due to changes in commodity prices are largely offset by corresponding changes in gas purchase expenses. Midstream Services had gathering revenues of $37.7 million in 2007 related to its gathering systems in Arkansas, compared to $7.9 million in 2006. Gathering volumes, revenues and expenses for this segment are expected to continue to grow at a fast pace as reserves related to our Fayetteville Shale play are developed and production increases.

Operating income from our Midstream Services segment increased 222% in 2007 as a result of the increases in gathering revenues and marketing margins, partially offset by increased operating costs and expenses. Operating income from our Midstream Services segment decreased 28% in 2006 due to increased operating costs and expenses that resulted from increased staffing and other costs associated with our growing gathering activities. The margin generated from natural gas marketing activities was up 10% in 2007 and up 8% in 2006 from the prior years. Margins fluctuate depending on the prices paid for commodities and the ultimate disposition of those commodities. The increase in volumes marketed in 2007 and 2006 resulted from marketing our increased production volumes, primarily related to our Fayetteville Shale play, and volumes for third parties in areas where we have production. Of the total volumes marketed, production from our E&P subsidiaries accounted for 91% in 2007, 86% in 2006 and 78% in 2005. 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 9 to the consolidated financial statements for additional information.

In 2006, our Midstream Services unit entered into a three-year firm transportation agreement with Ozark Gas Transmission System to transport volumes increasing to 220,000 MMBtu per day in the later stages of the contract. Additionally, in January 2007 we entered into a separate two-year firm transportation agreement with Ozark Gas Transmission System to transport volumes of 50,000 MMBtu per day. In 2006, one of our Midstream Services subsidiaries entered into a precedent agreement pursuant to which it will contract for firm gas transportation services on two newly-proposed pipeline laterals and related facilities of Texas Gas Transmission, LLC (Texas Gas), a subsidiary of Boardwalk Pipeline Partners, LP. Depending on regulatory approvals, the expected in-service date for both laterals is January 1, 2009. See "Contractual Obligations and Contingent Liabilities and Commitments" below for further discussion.

Natural Gas Distribution

	Year Ended December 31,		
	2007	2006	2005
	($ in thousands except for per Mcf amounts)		
Revenues	**$174,466**	$172,207	$178,482
Gas purchases	**$111,338**	$112,922	$120,852
Operating costs and expenses	**$ 53,168**	$ 54,811	$ 52,719
Operating income	**$ 9,960**	$ 4,474	$ 4,911
Sales and end-use transportation deliveries (Bcf)	**23.6**	21.8	23.2
Sales customers at year-end	**151,988**	151,003	147,820
Average sales rate per Mcf	**$ 11.07**	$ 12.30	$ 11.85
Heating weather - degree days	**3,699**	3,413	3,744
Percent of normal	**91%**	83%	91%

On November 9, 2007, we entered a definitive agreement for the sale of all capital stock of our utility subsidiary, AWG, to SourceGas LLC for $224 million plus working capital. The transaction is subject to certain closing conditions and regulatory approvals and is expected to close by mid-year 2008. The assets and liabilities associated with AWG have been reclassified as "held for sale" as of December 31, 2007 and 2006. Upon the consummation of the sale, we will cease to have any natural gas distribution operations.

Revenues and Operating Income

Gas distribution revenues fluctuate due to the effects of weather on demand for natural gas and the pass-through of gas supply cost changes. Because of the corresponding changes in purchased gas costs, the revenue effect of the pass-through of gas cost changes has not materially affected operating income. Revenues for 2007 increased 1% to $174.5 million compared to the prior year and revenues for 2006 decreased 4% to $172.2 million compared to the prior year. The increase in 2007 gas distribution revenues was due to an increase in volumes delivered and a rate increase implemented in August 2007. The decrease in 2006 gas distribution revenues was primarily due to lower sales volumes as a result of warmer weather, partially offset by a rate increase implemented in October 2005.

Operating income for our Natural Gas Distribution segment increased 123% in 2007 compared to the prior year and decreased 9% in 2006 compared to the prior year. The increase in 2007 operating income resulted primarily from the increase in revenues and decreased operating costs and expenses. The decrease in 2006 operating income resulted primarily from the decrease in revenues and increased operating costs and expenses. Weather during 2007 in the utility's service territory was 9% warmer than normal and 8% colder than the prior year. Weather during 2006 in the utility's service territory was 17% warmer than normal and 8% warmer than the prior year.

Deliveries and Rates

In 2007, AWG sold 15.0 Bcf to its customers at an average rate of $11.07 per Mcf, compared to 13.4 Bcf at $12.30 per Mcf in 2006 and 14.4 Bcf at $11.85 per Mcf in 2005. Additionally, AWG transported 8.6 Bcf in 2007, compared to 8.4 Bcf in 2006 and 8.8 Bcf in 2005 for its end-use customers. The increase in deliveries in 2007 compared to 2006 was primarily due to colder weather. The decrease in volumes sold in 2006 compared to 2005 primarily resulted from warmer than normal weather. The average sales rate per Mcf decreased in 2007 due to changes in natural gas prices and the impact of incremental volumes delivered. Deliveries in recent years have also been impacted by customer conservation brought about by higher gas prices.

Our utility segment hedged 4.0 Bcf of derivative gas purchases during 2007 which had the effect of increasing its total gas supply cost by $7.5 million. Our utility hedged 3.1 Bcf and 4.2 Bcf of its 2006 and 2005 gas purchases, respectively, which had the effect of increasing its total gas supply costs by $7.7 million and $2.4 million, respectively. Additionally, our utility segment has hedges in place on 2.0 Bcf of gas purchases at an average purchase price of $8.61 per Mcf for the 2007-2008 winter season. We refer you to "Quantitative and Qualitative Disclosures about Market Risk" and Note 9 to the consolidated financial statements for additional information.

AWG has a transportation contract with Ozark Gas Transmission System for approximately 66,900 MMBtu per day of firm capacity that expires in 2014. Deliveries are made by the pipeline to portions of AWG's distribution systems and to the interstate pipelines with which it interconnects.

Operating Costs and Expenses

The changes in purchased gas costs for the Natural Gas Distribution segment reflect volumes purchased, prices paid for supplies and the mix of purchases from various gas supply contracts (base load, swing and no-notice). Operating costs and expenses, net of purchased gas costs, decreased in 2007 to $53.2 million from $54.8 million in 2006. The decrease was primarily due to lower general and administrative expenses that resulted from a decrease in corporate expenses allocated to the Natural Gas Distribution segment. Operating costs and expenses for 2006 increased to $54.8 million from $52.7 million in 2005 primarily due to an increase in general and administrative expenses that resulted from increased salaries and incentive compensation costs.

Inflation impacts our Natural Gas Distribution segment by generally increasing our operating costs and the costs of our capital additions. Additionally, delays inherent in the rate-making process prevent us from obtaining immediate recovery of increased operating costs of our Natural Gas Distribution segment. Although general rates of inflation have been relatively low in recent years, the effects of inflation on the utility's operations may be intensified by higher inflation rates related to certain items such as steel, fuel, right-of-way acquisition costs and qualified labor.

Regulatory Matters

AWG's rates and operations are regulated by the APSC and it operates through municipal franchises that are perpetual by virtue of state law. These franchises, however, may not be exclusive within a geographic area. Although its rates for gas delivered to its retail customers are not regulated by the FERC, its transmission and gathering pipeline systems are subject to the FERC's regulations concerning open access transportation.

On January 12, 2006, the APSC initiated a notice of inquiry regarding a rulemaking for developing and implementing energy efficiency programs. Following a collaborative process, the APSC issued energy efficiency rules on January 11, 2007. These rules require all gas and electric utilities, excluding electric cooperatives, to file energy efficiency plans and programs with the APSC. AWG has filed and received approval for its initial energy efficiency plan, and is in the process of implementing Quick Start programs. Comprehensive programs are to be implemented in 2009. AWG will recover the costs of these programs from its customers. In AWG's most recent rate case, the APSC approved a Billing Determinant Adjustment Mechanism to mitigate the effects of lost revenues associated with energy efficiency programs.

On December 19, 2006, the APSC issued affiliate transactions rules. In January 2007, AWG and other utilities requested a rehearing of these rules. On February 16, 2007, the APSC issued an order granting rehearing and staying the implementation of the affiliate transaction rules pending further review. The APSC subsequently revised the rules to address concerns expressed by the parties to the rulemaking proceeding. AWG has filed Affiliate Transactions Compliance Procedures required by the rules, and we do not expect the final rules to have a material effect on its operations.

In July 2007, the APSC approved a rate increase for our utility segment totaling $5.8 million annually, exclusive of costs to be recovered through the utility's purchase gas adjustment clause. The rate increase became effective for billings rendered on or after August 1, 2007. The APSC order provided for an allowed return on equity of 9.5% and an assumed capital structure of 55% debt and 45% equity.

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 and $1.6 million in 2005. 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 2007, 2006 and 2005, other revenues included pre-tax gains of $6.4 million, $4.0 million and $3.1 million, respectively, related to the sale of gas-in-storage inventory.

Interest Expense and Interest Income

Interest costs, net of capitalization, increased to $23.9 million in 2007 due primarily to increased debt levels resulting from our increased level of capital investments. Interest expense decreased 95% to $0.7 million in 2006, as compared to the prior year, due to decreased debt levels resulting from our equity offering in September 2005 and increased capitalized interest. 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 $13.8 million in 2007, up from $11.8 million in 2006 and $6.0 million in 2005. Changes in capitalized interest are primarily due to the level of investment in unevaluated properties in our E&P segment and the capitalization of interest during the construction phase of our drilling rigs in 2006 and 2005. Costs excluded from amortization in the E&P segment increased to $372.4 million at December 31, 2007, compared to $166.8 million at December 31, 2006. Total capital investments for our E&P segment were $1.38 billion in 2007, up from $861.0 million in 2006.

During 2007, 2006 and 2005, we earned interest income of $0.1 million, $6.3 million and $3.4 million, respectively, related to our cash investments. These amounts are recorded in other income.

Income Taxes

Our provision for deferred income taxes was an effective rate of 38.1% for 2007, compared to 37.9% in 2006 and 36.9% in 2005. Any changes in the provision for deferred income taxes recorded each period result primarily from the level of income before income taxes, adjusted for permanent differences.

Pension Expense

We incurred pension costs of $5.3 million in 2007 for our pension and other postretirement benefit plans, compared to $4.0 million in 2006 and $2.7 million in 2005. The increase was primarily the result of an increase in our number of employees. The amount of pension expense recorded is determined by actuarial calculations and is also impacted by the funded status of our plans. During 2007, we contributed $6.5 million to our pension plans and $0.4 million to our other postretirement plans, compared to $3.4 million and $0.4 million, respectively, in 2006. For further discussion of our pension plans, we refer you to Note 5 to the consolidated financial statements and "Critical Accounting Policies" below.

Stock-Based Compensation Expense

We recognized expense of $5.4 million and capitalized $2.6 million to the full cost pool for stock-based compensation in 2007, compared to $5.2 million expensed and $1.7 million capitalized to the full cost pool for 2006 and $1.8 million expensed and $0.8 million capitalized to the full cost pool for 2005. We refer you to Note 10 to the consolidated financial statements for additional discussion of our equity-based compensation plans. Additionally in 2007, we recorded expense of $0.9 million and capitalized $0.6 million to the full cost pool related to the valuation of company shares held in our non-qualified deferred compensation plan.

Adoption of Accounting Principles

During the first quarter of 2007, we adopted FASB Interpretation No. 48, "Accounting for Uncertainty in Income Taxes" (FIN 48). FIN 48 provides guidance for recognizing and measuring uncertain tax positions, as defined in FAS 109. FIN 48 prescribes a threshold condition that a tax position must meet to be recognized in the financial statements. Guidance is also provided regarding de-recognition, classification and disclosure of these uncertain tax positions. FIN 48 was effective for fiscal years beginning after December 15, 2006. The adoption of FIN 48 had no material impact on our results of operations and financial condition. The income tax years 2004-2007 remain open to examination by the major taxing jurisdictions to which we are subject.

In September 2006, the Financial Accounting Standards Board issued SFAS 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. Prior to this statement, there were different definitions of fair value and limited guidance for applying those definitions in GAAP. In developing FAS 157, FASB considered the need for increased consistency and comparability in fair value measurements and for expanded disclosures about fair value measurements. This statement applies to other accounting pronouncements that require or permit fair value measurements. FAS 157 is effective for financial statements issued for fiscal years beginning after November 15, 2007. We will adopt FAS 157 in the first quarter of 2008 and will make additional required disclosures for financial instruments that are currently measured at fair value. In addition to required disclosures, FAS 157 also requires companies to evaluate current measurement techniques. We have not yet determined if any of its current fair value measurement methodology will change and, therefore, have not yet determined the impact FAS 157 may have on our results of operations or financial condition.

In February 2007, the Financial Accounting Standards Board issued SFAS 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. We have not yet determined the impact FAS 159 may have on our results of operations or financial condition.

In December 2007, the Financial Accounting Standards Board issued SFAS 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 could impact the presentation of our balance sheet line item “Minority Interest” related to our Overton partnership (see Note 1 for discussion), but is expected to have no impact on the results of operations.

In December 2007, the Financial Accounting Standards Board issued SFAS No. 141(R), “Business Combinations” (FAS 141R). FAS 141R provides greater consistency in the accounting and financial reporting of business combinations. It requires the acquiring entity in a business combination to recognize all assets acquired and liabilities assumed in the transaction, establishes the acquisition-date fair value as the measurement objective for all assets acquired and liabilities assumed, and requires the acquirer to disclose the nature and financial effect of the business combination. FAS 141R is effective for fiscal years beginning after December 15, 2008. We have not yet determined the impact FAS 141R may have on our results of operations or financial condition.

LIQUIDITY AND CAPITAL RESOURCES

We depend primarily on internally-generated funds, our unsecured revolving credit facility (discussed below under “Financing Requirements”) and funds accessed through debt and equity markets 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, 2007, we had $842.2 million outstanding under our revolving credit facility. At December 31, 2006, we had no indebtedness outstanding under our revolving credit facility. During 2008, we expect to draw on a portion of the funds available under our credit facility to fund our planned capital investments (discussed below under “Capital Investments”), which are expected to exceed the net cash generated by our operations.

On January 16, 2008, we consummated a private placement offering 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 down outstanding indebtedness under our revolving credit facility. On January 2, 2008, we entered into a $200 million short-term line of credit which was cancelled subsequent to the $600 million private placement offering. As of February 22, 2008, we had $328.2 million outstanding under our revolving credit facility.

Net cash provided by operating activities increased 45% to $622.7 million in 2007, compared to a 41% increase in 2006 to $429.9 million. The primary components of cash generated from operations are net income, depreciation, depletion and amortization, the provision for deferred income taxes and changes in operating assets and liabilities. Cash from operating activities increased in 2007 and 2006 due mainly to increased net income, adjusted for non-cash expenses. For 2007, requirements for our capital investments were met primarily by our revolving credit facility and cash provided by operating activities. Net cash from operating activities provided 41% of our cash requirements for capital investments in 2007, 46% in 2006 and 63% in 2005.

At December 31, 2007, our capital structure consisted of 37% debt and 63% equity. We believe that our operating cash flow, borrowings under our revolving credit facility and the expected proceeds from the sale of AWG and certain E&P asset divestitures will be adequate to meet our capital and operating requirements for 2008.

Our cash flow from operating activities is highly dependent upon the market prices that we receive for our gas and oil production. The price received for our production is also influenced by our commodity hedging activities, as more fully discussed in Note 9 to the consolidated financial statements included in this Form 10-K and Item 7A, "Quantitative and Qualitative Disclosures about Market Risk." Natural gas and oil prices are subject to wide fluctuations. As a result, we are unable to forecast with certainty our future level of cash flow from operations. We adjust our discretionary uses of cash dependent upon available cash flow.

Capital Investments

Our capital investments increased 59% to $1.5 billion in 2007 and increased 95% in 2006 to $942.4 million. Capital investments include a reduction of $20.6 million in 2007 and increases of $88.9 million and $28.1 million for 2006 and 2005, respectively, related to the change in accrued expenditures between years. Our E&P segment investments in 2007 were $1.38 billion, up from $861.0 million in 2006. Capital investments for 2006 and 2005 included $93.6 million and $35.1 million, respectively, for drilling rigs and related equipment which were subsequently sold and leased back in December 2006.

	2007	2006	2005
		(in thousands)	
Exploration and production			
Exploration and development	**$ 1,375,204**	$ 767,400	$ 416,161
Drilling rigs and related equipment	**4,453**	93,641	35,128
	1,379,657	861,041	451,289
Midstream services	**107,363**	48,660	15,840
Natural gas distribution	**11,375**	11,232	10,908
Other	**4,743**	21,474	5,014
	$ 1,503,138	$ 942,407	$ 483,051

Our capital investments for 2008 are planned to be $1.46 billion, consisting of $1.33 billion for E&P, $101 million for Midstream Services and $25 million for Natural Gas Distribution improvements and general purposes. We expect to allocate approximately $1.0 billion of our 2008 E&P capital to our Fayetteville Shale play, up from approximately $960 million in 2007. Our planned level of capital investments in 2008 will 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, generate new drilling prospects, and provide for improvements necessary due to normal customer growth in our Natural Gas Distribution segment through the closing date of the pending sale. As discussed above, our 2008 capital investment program is expected to be funded through cash flow from operations, borrowings under our credit facility and the expected proceeds from the sale of AWG and certain E&P assets. We may adjust the level of 2008 capital investments dependent upon our level of cash flow generated from operations and our ability to borrow under our credit facility.

Financing Requirements

Our total debt outstanding was $978.8 million at December 31, 2007, and $137.8 million at December 31, 2006. On October 12, 2007, we amended our unsecured revolving credit facility to, among other things, increase the current borrowing capacity to $1 billion. Pursuant to the amendment, the amount available under the revolving credit facility may be increased to $1.25 billion at any time upon our agreement with our existing or additional lenders. At December 31, 2007, we had $842.2 million outstanding under our revolving credit facility. 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. There were no borrowings under our revolving credit facility at December 31, 2006. 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, Southwestern Energy Production Company, SEECO, Inc. and Southwestern Energy Services Company and requires additional subsidiary guarantors if certain guaranty coverage levels are not satisfied. Our publicly traded notes were downgraded on August 1, 2006 by Standard and Poor's to BB+ with a stable outlook from BBB- with a negative outlook. We have a Corporate Family Rating of Ba2 by Moody's. Our 7.5% Senior Notes were rated BB+ by Standard and Poor's and Ba2 by Moody's. Any future 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, 2007. 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.

On January 16, 2008, we issued $600 million of 7.5% Senior Notes due 2018 in a private placement. The 7.5% notes are redeemable at our election, in whole or in part, at any time at a redemption price equal to the greater of: (i) 100% of the principal amount of the notes to be redeemed then outstanding; and (ii) the sum of the present values of the remaining scheduled payments of principal and interest on the notes to be redeemed as determined in accordance with the indenture, plus 50 basis points. Any redemption is also subject to payment of accrued and unpaid interest to the date of redemption. In addition, 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. The 7.5% Senior Notes are currently guaranteed by our subsidiaries, SEECO, Inc., Southwestern Energy Production Company and Southwestern Energy Services Company, which guarantees may be unconditionally released in certain circumstances. The indentures governing the 7.5% Senior Notes and our other existing notes contain covenants that, among other things, restrict the ability of us and/or our subsidiaries to incur liens, to engage in sale and leaseback transactions and to merge, consolidate or sell assets.

At December 31, 2007, our capital structure consisted of 37% debt and 63% equity. Stockholders' equity in the December 31, 2007 balance sheet includes an accumulated other comprehensive gain of $24.6 million 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 $11.3 million related to changes in our pension liability and the adoption 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 market values of our hedges at December 31, 2007, and does not necessarily reflect the value that we will receive or pay when the hedges ultimately are 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, 2007, would remain at 37% debt and 63% equity without consideration of the accumulated other comprehensive gains and losses related to FAS 133 and FAS 158.

As part of our strategy to ensure a certain level of cash flow to fund our operations, we have hedged approximately 70% of our expected 2008 gas production. The amount of long-term debt we incur will be dependent upon commodity prices, our capital investment plans and the actual proceeds from the sale of our utility or any E&P asset divestitures. If commodity prices remain at or near their current levels throughout 2008, assuming that we do not complete the sale of AWG or the divestitures of any E&P assets, our long-term debt would significantly increase in 2008. 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, two rigs yet to be delivered and related equipment and then leased such drilling rigs and equipment for an initial term of eight years commencing January 1, 2007, with aggregate annual rental payments of approximately $19.6 million. Subject to certain conditions, we have options to purchase the rigs and related equipment from the lessors at the end of the 84^{th} 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. We will incur additional annual rental payments of $1.4 million related to the 2007 transactions.

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, 2007, 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)		
Long-term debt[1]	$ 978,800	$ 1,200	$ 62,400	$ 844,600	$ 70,600
Interest on senior notes[2]	57,213	10,054	12,240	10,358	24,561
Operating leases[3]	62,795	10,801	19,667	16,118	16,209
Compression services[4]	47,205	13,146	21,886	12,173	—
Unconditional purchase obligations[5]	—	—	—	—	—
Operating agreements[6]	52,354	37,345	15,009	—	—
Demand charges[7]	101,251	32,146	25,983	21,960	21,162
Rig leases[8]	146,678	20,954	41,908	41,908	41,908
Other obligations[9]	29,053	28,693	360	—	—
	$ 1,475,349	$ 154,339	$ 199,453	$ 947,117	$ 174,440

(1) Debt includes $842.2 million borrowings outstanding under our revolving credit facility with a floating interest rate (5.87% at December 31, 2007) and $36.6 million of 7.15% Notes due 2018 which requires semi-annual principal payments of $0.6 million. On January 16, 2008, we issued $600 million of 7.5% Senior Notes, the proceeds of which were utilized to reduce the outstanding borrowings on our revolving credit facility.

(2) Interest on the senior notes includes interest through 2009 on the $60 million notes that are due in 2027 and putable at the holder's option in 2009.

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

(4) Our Midstream Services segment has commitments for approximately $39.3 million and our E&P segment has commitments for approximately $7.9 million for compression services associated primarily with our Fayetteville Shale play and our Overton operations.

(5) Our Natural Gas Distribution segment has volumetric commitments for the purchase of gas under non-cancelable competitive bid packages and non-cancelable wellhead contracts. Volumetric purchase commitments at December 31, 2007, totaled 0.9 Bcf, comprised of 0.8 Bcf in less than one year, 0.1 Bcf in one to three years and less than 0.1 Bcf in three to five years. Our volumetric purchase commitments are priced primarily at regional gas indices set at the first of each future month. These costs are recoverable from the utility's end-use customers. Upon the consummation of the sale of AWG, we will cease to have these volumetric commitments.

(6) Our E&P segment has commitments for up to $41.1 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 $938,000, expiring in December 2008.

(7) Our Midstream Services segment has commitments for demand transportation charges of approximately $22.9 million related to the Fayetteville Shale play and approximately $5.2 million related to Angelina. Our Natural Gas Distribution segment has commitments for approximately $71.4 million of demand charges on non-cancelable firm gas purchase and firm transportation agreements. These costs are recoverable from the utility's end-use customers. Our E&P segment has commitments for approximately $1.8 million of demand transportation charges.

(8) Our E&P segment has commitments related to the leasing of 15 drilling rigs and related equipment through 2014.

(9) Our other significant contractual obligations include approximately $14.4 million related to seismic services, approximately $7.9 million for funding of benefit plans and approximately $1.9 million for various information technology support and data subscription agreements. Additionally, our E&P segment has committed up to $3.9 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 long-term debt.

Contingent Liabilities and Commitments

We have the following commitments and contingencies that could create liabilities for us or increase or accelerate our contingent liabilities. Substantially all of our employees are covered by defined benefit and postretirement benefit plans. Our return on the assets of these plans, when combined with other factors including an increase in employees, resulted in an increase in pension expense and our required funding of the plans for 2007, 2006 and 2005. At December 31, 2007, we recognized a liability of $14.6 million as a result of the underfunded status of our pension and other postretirement benefit plans, compared to a liability of $13.8 million at December 31, 2006. As a result of actuarial data, and assuming the closing of the sale of AWG by mid-year, we expect to record expenses of $4.8 million for these plans in 2008. See Note 5 to the consolidated financial statements and "Critical Accounting Policies" below for additional information.

In 2006, our Midstream Services segment entered into a three-year firm transportation agreement with Ozark Gas Transmission System to transport volumes increasing to 220,000 MMBtu per day in the latter stage of the contract. Additionally, in January 2007, our Midstream Services segment entered into a separate two-year firm transportation agreement with Ozark Gas Transmission System to transport volumes of 50,000 MMBtu per day.

In December 2006, one of our Midstream Services subsidiaries entered into a precedent agreement pursuant to which we will contract for firm gas transportation services on two newly-proposed pipeline laterals and related facilities of Texas Gas Transmission, LLC (Texas Gas), a subsidiary of Boardwalk Pipeline Partners, LP. We will be a “Foundation Shipper” for the project and will use the proposed laterals and related facilities primarily to deliver gas volumes produced from Southwestern’s operations in its Fayetteville Shale play in central Arkansas. Depending on regulatory approvals, the expected in-service date for both laterals is January 1, 2009. The first lateral line (Fayetteville Lateral) will originate in Conway County, Arkansas, and connect to Texas Gas’ mainline system in Coahoma County, Mississippi. The Fayetteville Lateral will be a minimum of 36” in diameter and would have an estimated ultimate capacity of up to 1.1 Bcf per day. The second lateral (Greenville Lateral) will originate at the Texas Gas mainline system near Greenville, Mississippi, and extend eastward to interconnect with various interstate pipelines. The firm transportation agreements entered into by us pursuant to the precedent agreement will have an initial term of ten years and, over time, will enable us to transport up to 500,000 MMBtu per day on the Fayetteville Lateral and up to 400,000 MMBtu per day on the Greenville Lateral. We will also have the option to acquire up to 300,000 MMBtu per day of additional capacity on the Fayetteville Lateral and up to 240,000 MMBtu per day of additional capacity on the Greenville Lateral. Upon execution and delivery of the firm transportation agreements contemplated by the precedent agreement, our Midstream Services segment would have additional demand charges of $503.5 million that would be payable over the ten-year term of the agreements.

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. 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.

Working Capital

We maintain access to funds that may be needed to meet capital requirements through our revolving credit facility described above. We had negative working capital of $67.6 million at the end of 2007 and negative working capital of $55.0 million at the end of 2006. Current assets at December 31, 2007, increased $49.3 million, compared to current assets at December 31, 2006, due to increases in accounts receivable related to gas marketing sales and sales of oil and gas production, partially offset by a $42.0 million decrease in cash equivalents. Current liabilities increased $52.0 million at December 31, 2007, due primarily to an increase in accounts payable related to our level of drilling activity, partially offset by a decrease in our current hedging liability.

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, 2007, 2006 and 2005, our unamortized costs of natural gas and oil properties did not exceed this ceiling amount. 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, adjusted for market differentials. Cash flow hedges of gas production in place at December 31, 2007, increased the calculated ceiling value by approximately $163 million (net of tax). We had approximately 181.0 Bcf of future gas production hedged at December 31, 2007. 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, and at December 31, 2005, the ceiling value of our reserves was calculated based upon quoted market prices of $10.08 per Mcf for Henry Hub gas and $61.04 per barrel for West Texas Intermediate oil. Decreases in market prices from December 31, 2007 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 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.

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 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 the president of our E&P subsidiaries. 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 64% of our total reserve base at December 31, 2007. 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. Netherland, Sewell & Associates, Inc. reports the results of the reserves audit to our Board of Directors. In conducting its audit, the engineers and geologists of Netherland, Sewell & Associates 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 81% 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 the lowest value properties and are not reviewed in the audit. The fields included in approximately the top 81% present value as of December 31, 2007, accounted for approximately 85% of our total proved reserves and approximately 90% 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, 2007, Netherland, Sewell & Associates 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 96% 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, 2007, were $2,015.2 million and 1,450.3 Bcfe. An assumed decrease of $1.00 per Mcf in the December 31, 2007 gas price used to price our reserves would have resulted in an approximate $350 million decline in our future cash flows discounted at 10%, adjusted for the effects of commodity hedges, and an approximate decrease of 14 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 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 policies prohibit speculation with derivatives and limit swap agreements to counterparties with appropriate credit standings to minimize the risk of uncollectability. In recent years, we have hedged 70% 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 offset by the gain or loss recognized upon the related sale or purchase of the natural gas or sale of the oil that is hedged.

Our derivative instruments are accounted for under FAS 133, as amended by FAS 138 and FAS 149, 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 or interest rates, 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. Results of settled interest rate hedges are reflected in interest expense. 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, 2007, we recorded an unrealized gain of $6.0 million related to basis differential swaps that did not qualify for hedge accounting in addition to a $1.0 million gain 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 2007, 2006 or 2005. We refer 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.

Regulated Utility Operations

Our utility operations are subject to the rate regulation and accounting requirements of the APSC. Allocations of costs and revenues to accounting periods for ratemaking and regulatory purposes may differ from those generally applied by non-regulated operations. Such allocations to meet regulatory accounting requirements are considered generally accepted accounting principles for regulated utilities provided that there is a demonstrated ability to recover any deferred costs in future rates.

During the ratemaking process, the APSC may require a utility to defer recognition of certain costs to be recovered through rates over time as opposed to expensing such costs as incurred. This allows the utility to stabilize rates over time rather than passing such costs on to the customer for immediate recovery. This causes certain expenses to be deferred as a regulatory asset and amortized to expense as they are recovered through rates. The APSC has not required any unbundling of services, although large industrials are free to contract for their own gas supply. There are no pending regulations relating to unbundling of services; however, should such regulation be proposed and adopted, certain of these assets may no longer meet the criteria for deferred recognition and, accordingly, a write-off of regulatory assets and stranded costs could be required.

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 5 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, 2007, benefit obligation and the periodic benefit cost to be recorded in 2008, the discount rate assumed is 6.0%. For the 2008 periodic benefit cost, the expected return assumed is 7.75%. This compares to a discount rate of 6.0% and an expected return of 8.0% used in 2007.

Using the assumed rates discussed above, we recorded pension expense of $5.3 million in 2007, $4.0 million in 2006 and $2.7 million in 2005 related to our pension and other postretirement benefit plans. At December 31, 2007, we recognized a liability of $14.6 million, compared to $13.8 million at December 31, 2006, related to our pension and other postretirement benefit plans. During 2007, we also funded $6.9 million to our pension and other postretirement benefit plans. In 2008, we expect to fund $7.9 million to our pension and other postretirement benefit plans and recognize pension expense of $4.2 million and a postretirement benefit expense of $0.6 million, assuming the sale of the Natural Gas Distribution segment closes mid-year. Assuming a 1% change in the 2007 rates (lower discount rate and lower rate of return), we would have recorded pension expense of $5.9 million in 2007.

Gas in Underground Storage

We record our gas stored in inventory that is owned by the E&P segment at the lower of weighted average cost or market. Gas expected to be cycled within the next 12 months is recorded in current assets with the remaining stored gas reflected as a long-term asset. The quantity and average cost of gas in storage was 10.1 Bcf at $4.05 per Mcf at December 31, 2007, compared to 9.6 Bcf at $3.89 per Mcf at December 31, 2006.

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, which are passed through to the utility’s customers, 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,” “target” or similar expressions.

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:

- the timing and extent of changes in market conditions and prices for natural gas and oil (including regional basis differentials);
- the timing and extent of our success in discovering, developing, producing and estimating reserves;
- 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;
- our ability to fund our planned capital investments;
- our ability to determine the most effective and economic fracture stimulation for the Fayetteville Shale formation;
- the impact of federal, state and local government regulation, including any increase in severance taxes;

- 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;
- our future property acquisition or divestiture activities;
- the effects of weather;
- increased competition;
- the financial impact of accounting regulations and critical accounting policies;
- the comparative cost of alternative fuels;
- conditions in capital markets and changes in interest rates, 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, 2007, approximately 36% of our estimated proved reserves were proved undeveloped and 4% 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.

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 and interest rate risks. 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 5% of accounts receivable at December 31, 2007. In addition, please see the discussion of credit risk associated with commodities trading below.

Interest Rate Risk

The following table provides information on our financial instruments that are sensitive to changes in interest rates. The table presents the principal cash payments for our debt obligations and related weighted-average interest rates by expected maturity dates. At December 31, 2007, we had $842.2 million borrowings outstanding under our revolving credit facility with a floating interest rate (5.87% at December 31, 2007). Our policy is to manage interest rates through use of a combination of fixed and floating rate debt. Interest rate swaps may be used to adjust interest rate exposures when appropriate. We do not have any interest rate swaps in effect currently.

	Expected Maturity Date							Fair Value
	2008	2009	2010	2011	2012	Thereafter	Total	12/31/07
				($ in millions)				
Fixed Rate	$ 1.2	$ 61.2	$ 1.2	$ 1.2	$ 1.2	$ 70.6	$ 136.6	$ 134.2
Average Interest Rate	7.15%	7.62%	7.15%	7.15%	7.15%	7.18%	7.38%	—
Variable Rate	$ —	$ —	$ —	$ —	$ 842.2	$ —	$ 842.2	$ 842.2
Average Interest Rate	—	—	—	—	5.87%	—	5.87%	—

Commodities Risk

We use over-the-counter natural gas and crude oil swap agreements and options to hedge sales of our production, to hedge activity in our Midstream Services segment and to hedge the purchase of gas in our Natural Gas Distribution 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 (production hedge) or receives (gas purchase hedge) 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 (production hedge) or receive from (gas purchase hedge) 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 offset by the gain or loss recognized upon the related sale or purchase of the natural gas or sale of the oil 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 periodically reviewed to limit our credit risk exposure.

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, 2007, the fair value of our financial instruments related to natural gas production and underground storage sales was a $47.6 million asset.

	Volume	Weighted Average Price to be Swapped ($)	Weighted Average Floor Price ($)	Weighted Average Ceiling Price ($)	Weighted Average Basis Differential ($)	Fair Value at Dec 31, 2007 ($ in millions)
Natural Gas (Bcf):						
Fixed Price Swaps:						
2008(1)	55.7	8.27	-	-	-	25.6
2009	56.0	8.20	-	-	-	(10.8)
Costless Collars:						
2008	48.0	-	7.92	11.60	-	30.5
2009	23.0	-	8.09	10.91	-	2.9
Basis Swaps:						
2008	63.2	-	-	-	(0.45)	(0.5)
2009	3.6	-	-	-	(0.44)	(0.2)
Matched-Basis Swaps:						
2008	8.0	-	-	-	(0.73)	0.1

(1) Includes fixed-price swaps for 1.7 Bcf relating to future sales from our underground storage facility that have a fair value asset of $2.3 million.

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. At December 31, 2007, we also had outstanding fixed-price basis differential swaps on 63.2 Bcf of 2008 and 3.6 Bcf of 2009 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, 2007, we recorded an unrealized gain of $6.0 million related to the differential swaps that did not qualify for hedge accounting treatment and a $1.0 million gain related to the change in estimated ineffectiveness of our cash flow hedges. Typically, our 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.

At December 31, 2006, we had outstanding natural gas price swaps on total notional volumes of 32.5 Bcf in 2007 and 13.0 Bcf in 2008 for which we will receive fixed prices ranging from $6.20 to $12.06 per MMBtu. At December 31, 2006, we had outstanding fixed price basis differential swaps on 40.4 Bcf of 2007 and 2008 gas production that qualified for hedge treatment and outstanding fixed price basis differential swaps on 62.0 Bcf of 2007 and 2008 gas production that did not qualify for hedge treatment.

At December 31, 2006, we had collars in place on notional volumes of 34.0 Bcf in 2007 and 22.0 Bcf in 2008. The 34.0 Bcf in 2007 had an average floor and ceiling price of $6.93 and $12.34 per MMBtu, respectively. The 22.0 Bcf in 2008 had an average floor and ceiling price of $7.92 and $13.15 per MMBtu, respectively.

Subsequent to December 31, 2007 and prior to February 22, 2008, we hedged 16.0 Bcf of 2008, 17.0 Bcf of 2009 and 16.0 Bcf of 2010 gas production under fixed price swaps with average prices of $8.99, $8.53 and $8.55 per Mcf, respectively. In addition, we hedged 8.0 Bcf of 2009 and 2.0 Bcf of 2010 gas production using costless collars. The collars relating to 2009 production have a weighted average floor and ceiling price of $8.00 and $10.05 per Mcf, respectively; and the collars relating to 2010 production have a weighted average floor and ceiling price of $8.50 and $10.20 per Mcf, respectively. We have also basis protected an additional 2.1 Bcf of 2008 gas production with an average differential price of $0.26 below NYMEX spot rates for our respective basis locations.

Midstream Services

At December 31, 2007, our Midstream Services segment had outstanding fair value hedges in place on 1.0 Bcf of gas. 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 2008 through December 2008 and have fair value asset of $0.8 million as of December 31, 2007. A liability of $0.7 million was recognized at December 31, 2007, as an offset to these hedges for physical gas purchases and sales commitments relating specifically to the hedged transactions.

Natural Gas Distribution

At December 31, 2007, our Natural Gas Distribution segment had outstanding hedges in place on 2.0 Bcf of gas. These hedges are fixed-price swap purchases that relate to the utility's planned and discretionary hedging program for the winter heating season. These hedges have contract months from January 2008 through March 2008, and have a fair value liability of $2.4 million as of December 31, 2007. Hedging gains and losses for our Natural Gas Distribution segment are a component of the overall gas cost paid by the utility's customers.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

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, 2007. 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, 2007, 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, 2007 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, 2007 and 2006, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2007 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, 2007, 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 in 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.

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 28, 2008

STATEMENTS OF OPERATIONS

Southwestern Energy Company and Subsidiaries

	For the years ended December 31,		
	2007	2006	2005
	(in thousands, except share/per share amounts)		
Operating revenues:			
Gas sales	**$ 870,047**	$ 572,354	$ 503,111
Gas marketing	**316,912**	136,698	132,690
Oil sales	**42,434**	40,742	30,026
Gas gathering, transportation and other	**25,738**	13,318	10,502
	1,255,131	763,112	676,329
Operating costs and expenses:			
Gas purchases – midstream services	**306,336**	128,387	124,730
Gas purchases – gas distribution	**85,445**	79,363	82,689
Operating expenses	**85,826**	66,579	52,850
General and administrative expenses	**80,269**	66,112	48,650
Depreciation, depletion and amortization	**293,914**	151,290	96,211
Taxes, other than income taxes	**21,875**	25,109	25,279
	873,665	516,840	430,409
Operating income	**381,466**	246,272	245,920
Interest expense:			
Interest on long-term debt	**36,191**	11,099	19,791
Other interest charges	**1,474**	1,402	1,254
Interest capitalized	**(13,792)**	(11,822)	(6,005)
	23,873	679	15,040
Other income (expense)	**(219)**	17,079	4,784
Income before income taxes and minority interest	**357,374**	262,672	235,664
Minority interest in partnership	**(345)**	(637)	(1,473)
Income before income taxes	**357,029**	262,035	234,191
Provision for income taxes:			
Current	**—**	—	—
Deferred	**135,855**	99,399	86,431
	135,855	99,399	86,431
Net income	**$ 221,174**	$ 162,636	$ 147,760
Basic earnings per share	**$1.31**	$0.97	$0.98
Diluted earnings per share	**$1.27**	$0.95	$0.95
Weighted average common shares outstanding:			
Basic	**169,476,723**	167,303,141	150,892,602
Effect of:			
Stock options	**4,012,099**	3,476,701	4,512,564
Restricted stock awards	**232,508**	507,908	903,873
Diluted	**173,721,330**	171,287,750	156,309,039

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

BALANCE SHEETS

Southwestern Energy Company and Subsidiaries

	December 31, 2007	December 31, 2006
	(in thousands)	
ASSETS		
Current assets		
Cash and cash equivalents	**$ 727**	$ 42,867
Accounts receivable	**177,680**	100,139
Inventories, at average cost	**33,034**	25,981
Hedging asset - FAS 133	**64,472**	64,082
Current assets held for sale (see Note 2)	**58,877**	67,395
Other	**28,551**	13,620
Total current assets	**363,341**	314,084
Property, plant and equipment, at cost		
Gas and oil properties, using the full cost method, including $372.4 million in 2007 and $166.8 million in 2006 excluded from amortization	**4,020,448**	2,651,427
Gathering systems	**158,604**	51,836
Gas in underground storage	**13,349**	13,349
Other	**85,983**	75,282
	4,278,384	2,791,894
Less: Accumulated depreciation, depletion and amortization	**1,200,754**	913,233
	3,077,630	1,878,661
Assets held for sale (see Note 2)	**143,234**	139,523
Other assets	**38,511**	46,801
	$ 3,622,716	$ 2,379,069
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities		
Current portion of long-term debt	**$ 1,200**	$ 1,200
Accounts payable	**313,070**	261,177
Taxes payable	**5,087**	10,271
Advances from partners	**32,005**	25,048
Hedging liability - FAS 133	**8,598**	15,799
Current deferred income taxes	**20,909**	19,162
Current liabilities associated with assets held for sale (see Note 2)	**39,118**	37,732
Other	**10,908**	8,471
Total current liabilities	**430,895**	378,860
Long-term debt	**977,600**	136,600
Other liabilities		
Deferred income taxes	**479,196**	354,702
Long-term hedging liability	**15,186**	4,902
Pension liability	**12,268**	11,697
Liabilities associated with assets held for sale (see Note 2)	**15,417**	16,621
Other	**35,084**	30,010
	557,151	417,932
Commitments and contingencies		
Minority interest in partnership	**10,570**	11,034
Stockholders' equity		
Common stock, $0.01 par value; authorized 540,000,000 shares, issued 170,790,836 in 2007 and 168,953,893 in 2006	**1,708**	1,690
Additional paid-in capital	**754,077**	740,609
Retained earnings	**882,031**	660,857
Accumulated other comprehensive income	**13,348**	31,487
Common stock in treasury, 111,387 shares in 2007	**(4,664)**	—
	1,646,500	1,434,643
	$ 3,622,716	$ 2,379,069

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

STATEMENTS OF CASH FLOWS

Southwestern Energy Company and Subsidiaries

	For the years ended December 31,		
	2007	2006	2005
		(in thousands)	
Cash flows from operating activities			
Net income	**$ 221,174**	$ 162,636	$ 147,760
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, depletion and amortization	**295,332**	152,519	97,652
Deferred income taxes	**135,855**	99,399	86,431
Unrealized (gain) loss on derivatives	**(7,103)**	5,579	(9,666)
Stock-based compensation expense	**6,377**	5,164	1,906
Minority interest in partnership	**(465)**	(579)	(245)
Gain on sale of investment in partnership and other property	**—**	(10,285)	(445)
Equity in income of NOARK partnership	**—**	(925)	(1,635)
Change in assets and liabilities:			
Accounts receivable	**(76,136)**	(2,422)	(42,680)
Inventories	**(10,800)**	(12,975)	(17,265)
Under/over-recovered purchased gas costs	**5,709**	3,258	5,911
Accounts payable	**61,284**	20,742	32,837
Advances from partners and customer deposits	**7,615**	24,317	1,513
Other assets and liabilities	**(16,107)**	(16,491)	2,408
Net cash provided by operating activities	**622,735**	429,937	304,482
Cash flows from investing activities			
Capital investments	**(1,519,433)**	(850,910)	(453,859)
Proceeds from sale and leaseback of drilling rigs and related equipment	**3,066**	127,288	—
Proceeds from sale of investment in partnership and other property	**2,725**	92,465	1,519
Other items	**145**	1,151	(578)
Net cash used in investing activities	**(1,513,497)**	(630,006)	(452,918)
Cash flows from financing activities			
Issuance of common stock	**—**	—	579,956
Debt retirement	**(1,200)**	(1,200)	(125,000)
Payments on revolving long-term debt	**(916,550)**	(267,700)	(563,800)
Borrowings under revolving long-term debt	**1,758,750**	267,700	463,800
Debt issuance costs	**(2,000)**	—	(1,180)
Excess tax benefit for stock-based compensation	**—**	14,609	—
Change in bank drafts outstanding	**5,193**	2,009	11,860
Proceeds from exercise of common stock options	**5,474**	3,873	5,270
Net cash provided by financing activities	**849,667**	19,291	370,906
Increase (decrease) in cash and cash equivalents	**(41,095)**	(180,778)	222,470
Cash and cash equivalents at beginning of year	**42,927**	223,705	1,235
Cash and cash equivalents at end of year	**$ 1,832**	$ 42,927	$ 223,705

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

STATEMENTS OF CHANGES IN STOCKHOLDERS' EQUITY AND COMPREHENSIVE INCOME (LOSS)

Southwestern Energy Company and Subsidiaries

	Common Stock (1) Shares Issued	Common Stock (1) Amount	Additional Paid-In Capital (1)	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Common Stock in Treasury	Unamortized Restricted Stock Awards	**Total**
				(in thousands)				
Balance at December 31, 2004	148,902	$ 14,890	$ 117,586	$ 350,461	$ (19,816)	$ (9,156)	$ (6,288)	**$ 447,677**
Comprehensive income:								
Net income	—	—	—	147,760	—	—	—	**147,760**
Change in value of derivatives	—	—	—	—	(81,044)	—	—	**(81,044)**
Change in value of pension liability	—	—	—	—	(4,014)	—	—	**(4,014)**
Total comprehensive income								**62,702**
Issuance of common stock	19,550	1,955	578,001	—	—	—	—	**579,956**
Exercise of stock options	—	—	11,821	—	—	5,526	—	**17,347**
Issuance of restricted stock	—	—	3,909	—	—	368	(4,277)	**—**
Cancellation of restricted stock	—	—	(121)	—	—	(128)	249	**—**
Amortization of restricted stock	—	—	—	—	—	—	2,622	**2,622**
Balance at December 31, 2005	168,452	$ 16,845	$ 711,196	$ 498,221	$ (104,874)	$ (3,390)	$ (7,694)	**$ 1,110,304**
Comprehensive income:								
Net income	—	—	—	162,636	—	—	—	**162,636**
Change in value of derivatives	—	—	—	—	141,230	—	—	**141,230**
Change in value of pension liability	—	—	—	—	2,372	—	—	**2,372**
Total comprehensive income								**306,238**
Adoption of FAS 158	—	—	—	—	(7,241)	—	—	**(7,241)**
Adoption of FAS 123(R)	—	—	(7,694)	—	—	—	7,694	**—**
Tax benefit for stock-based compensation	—	—	14,609	—	—	—	—	**14,609**
Stock-based compensation – FAS 123(R)	—	—	6,857	—	—	3	—	**6,860**
Common stock par value adjustment	—	(15,160)	15,160	—	—	—	—	**—**
Exercise of stock options	494	5	927	—	—	2,941	—	**3,873**
Issuance of restricted stock	8	—	(513)	—	—	513	—	**—**
Cancellation of restricted stock	—	—	67	—	—	(67)	—	**—**
Balance at December 31, 2006	168,954	$ 1,690	$ 740,609	$ 660,857	$ 31,487	$ —	$ —	**$ 1,434,643**
Comprehensive income:								
Net income	—	—	—	221,174	—	—	—	**221,174**
Change in value of derivatives	—	—	—	—	(16,775)	—	—	**(16,775)**
Change in value of pension liability	—	—	—	—	(1,364)	—	—	**(1,364)**
Total comprehensive income								**203,035**
Stock-based compensation – FAS 123(R)	—	—	8,012	—	—	—	—	**8,012**
Exercise of stock options	1,707	17	5,457	—	—	—	—	**5,474**
Issuance of restricted stock	153	1	(1)	—	—	—	—	**—**
Cancellation of restricted stock	(25)	—	—	—	—	—	—	**—**
Treasury stock – non-qualified plan	—	—	—	—	—	(4,664)	—	**(4,664)**
Balance at December 31, 2007	170,789	$ 1,708	$ 754,077	$ 882,031	$ 13,348	$ (4,664)	$ —	**$ 1,646,500**

(1) 2004 restated to reflect the two-for-one stock splits effected on June 3, 2005 and November 17, 2005.

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

STATEMENTS OF CHANGES IN STOCKHOLDERS' EQUITY AND COMPREHENSIVE INCOME (LOSS)

Southwestern Energy Company and Subsidiaries

STATEMENT OF COMPREHENSIVE INCOME (LOSS)

	For the years ended December 31,		
	2007	2006	2005
		(in thousands)	
Net income	**$ 221,174**	$ 162,636	$ 147,760
Change in value of derivatives			
Current period reclassification to earnings	**(42,956)**	(2,326)	67,481
Current period ineffectiveness	**(618)**	(12,726)	5,969
Current period change in derivative instruments	**26,799**	156,282	(154,494)
Total change in value of derivatives	**(16,775)**	141,230	(81,044)
Current period change in pension and other postretirement liability	**(1,364)**	2,372	(4,014)
Comprehensive income, end of year	**$ 203,035**	$ 306,238	$ 62,702

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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Southwestern Energy Company and Subsidiaries
December 31, 2007, 2006 and 2005

(1) SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Nature of Operations and Consolidation

Southwestern Energy Company (Southwestern or the Company) is an independent energy company primarily focused on natural gas. Through its wholly-owned subsidiaries, the Company is engaged in natural gas and oil exploration and production, natural gas gathering, transmission and marketing, and natural gas distribution. Southwestern's exploration and production (E&P) activities are concentrated in Arkansas, Texas and Oklahoma. Southwestern's marketing and gas gathering business (Midstream Services) is concentrated in the core areas of its E&P operations. The Natural Gas Distribution segment operates in northern Arkansas and its customers consist of residential, commercial and industrial users of natural gas.

The consolidated financial statements include the accounts of Southwestern and its wholly-owned subsidiaries, including Southwestern Energy Production Company (SEPCO), SEECO, Inc., Arkansas Western Gas Company (AWG), Southwestern Midstream Services Company (SMS), Diamond "M" Production Company and A.W. Realty Company. The consolidated financial statements also include the results for (i) Overton Partners, L.P., of which SEPCO is the sole general partner, (ii) DeSoto Drilling Inc., (iii) Angelina Gathering Company, L.L.C., and (iv) DeSoto Gathering Company, L.L.C. All significant intercompany accounts and transactions have been eliminated. Prior to the sale of its interest in 2006, the Company accounted for its general partnership interest in the NOARK Pipeline System, Limited Partnership (NOARK) using the equity method of accounting. In accordance with Statement of Financial Accounting Standards No. 71, "Accounting for the Effects of Certain Types of Regulation," the Company recognizes profit on intercompany sales of gas delivered to storage by its utility subsidiary.

The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities, if any, at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

On November 9, 2007, the Company signed a Stock Sale and Purchase Agreement for the sale of all capital stock of AWG to SourceGas LLC for $224 million plus working capital. The transaction is subject to certain closing conditions and regulatory approvals and is expected to close approximately mid-year 2008. Pursuant to Statement of Financial Accounting Standards No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets" (FAS 144), the assets and liabilities of AWG have been reclassified as "held for sale" in the December 31, 2007 and 2006 balance sheets. The E&P segment sells natural gas to AWG and the cash flows from these sales are deemed "significant" under accounting rules. Therefore, the results of operations for AWG are consolidated in the statements of operations and are not presented as "discontinued operations."

Certain reclassifications have been made to the prior years' financial statements to conform to the 2007 presentation. The effects of the reclassifications were not material to the Company's consolidated financial statements.

Minority Interest in Partnership

In 2001, SEPCO formed a limited partnership, Overton Partners, L.P., with an investor to drill and complete 14 development wells in SEPCO's Overton Field located in Smith County, Texas. Because SEPCO is the sole general partner and owns a majority interest in the partnership, the operating and financial results are consolidated with the Company's exploration and production results and the investor's share of the partnership activity is reported as a minority interest item in the financial statements. SEPCO contributed 50% of the capital required to drill the 14 wells. Revenues and expenses are allocated 65% to SEPCO prior to payout of the investor's initial investment and 85% thereafter. Under the terms of the partnership agreement, the partnership has a maximum life of 50 years. At December 31, 2007, the estimated fair value of the minority ownership position of the partnership does not exceed the minority interest of $10.6 million reflected in the accompanying balance sheet.

Rig Sale and Leaseback

On December 29, 2006, the Company entered into a sale and leaseback transaction pursuant to which it sold 13 operating drilling rigs, two rigs yet to be delivered and related equipment and then leased such drilling rigs and equipment for an initial term of eight years commencing January 1, 2007, with aggregate annual rental payments of approximately $19.6 million. The Company received proceeds of $127.3 million. Subject to certain conditions, the Company has options to purchase the rigs and related equipment from the lessors at the end of the 84^{th} 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, the Company has 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, the Company 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. The Company will incur additional annual rental payments of $1.4 million related to this transaction. In accordance with the Company's accounting procedures, the lease payments for the drilling rigs, as well as other operating expenses for the Company's drilling operations, are capitalized to the full cost pool and are partially offset by billings to third-party working interest owners for their share of rig day-rate charges.

Inventory

Inventory recorded in current assets includes $25.0 million at December 31, 2007, and $21.4 million at December 31, 2006, for gas in underground storage owned by the Company's E&P segment, and $8.1 million at December 31, 2007, and $4.6 million at December 31, 2006, for tubulars and other equipment used in the Company's E&P segment. Additionally, the Natural Gas Distribution segment has current gas in underground storage of $21.6 million and $24.1 million at December 31, 2007 and 2006, respectively, that is classified in the balance sheets as "Current Assets Held for Sale."

Gas in underground storage owned by the Company's E&P segment is carried at the lower of cost or market. In determining the lower of cost or market for this storage gas, the Company combines the current gas in underground storage with long-term gas in underground storage (recorded in property, plant and equipment) and compares the total average weighted cost for the facility to the gas futures market. The combined quantity and average cost of gas in storage was 10.1 Bcf at $4.05 per Mcf at December 31, 2007, compared to 9.6 Bcf at $3.89 per Mcf at December 31, 2006. Current gas in underground storage owned by the Company's Natural Gas Distribution segment is recoverable from the utility's customers when it is withdrawn and used as gas supply. Gas in underground storage for both segments is accounted for by a moving weighted average cost method whereby gas withdrawn from storage is relieved at the overall weighted average cost of current gas remaining in the facility.

Other assets includes $16.7 million at December 31, 2007, and $9.8 million at December 31, 2006, for non-current inventory held by the Midstream Services segment consisting primarily of tubulars that will be used to construct gathering systems for the Fayetteville Shale play.

Tubulars and other equipment used by the Company's segments are carried at the lower of cost or market and are accounted for by a moving weighted average cost method that is applied within specific classes of inventory items. Purchases of inventory are recorded at cost and inventory is relieved at the weighted average cost of items remaining within a specified class.

Property, Depreciation, Depletion and Amortization

Gas and Oil Properties. The Company utilizes 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, 2007, 2006 and 2005, the Company's unamortized costs of natural gas and oil properties did not exceed this ceiling amount. At December 31, 2007, the ceiling value of the Company's 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, adjusted for market differentials. Cash flow hedges of gas production in place at December 31, 2007, increased the calculated ceiling value by approximately $163 million (net of tax). The Company had approximately 181.0 Bcf of future gas production hedged at December 31, 2007. At December 31, 2006, the ceiling value of the Company's 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, and at December 31, 2005, the ceiling value of the Company's reserves was calculated based upon quoted market prices of $10.08 per Mcf for Henry Hub gas and $61.04 per barrel for West Texas Intermediate oil. Decreases in market prices from December 31, 2007 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.

Gathering Systems. The Company's investment in gathering systems is primarily related to its Fayetteville Shale play in Arkansas. These assets are being depreciated on a straight-line basis over 25 years.

Gas Distribution Systems. Costs applicable to construction activities, including overhead items, are capitalized. Depreciation and amortization of the gas distribution system is provided using the straight-line method with average annual rates for plant functions ranging from 1.2% to 4.2%.

Other property, plant and equipment is depreciated using the straight-line method over estimated useful lives ranging from 7 to 24 years.

The Company charges to maintenance or operations the cost of labor, materials and other expenses incurred in maintaining the operating efficiency of its properties. Betterments are added to property accounts at cost. Retirements are credited to property, plant and equipment at cost and charged to accumulated depreciation, depletion and amortization with no gain or loss recognized, except for abnormal retirements such as the sale or disposition of a large operating unit or system.

Gas in Underground Storage. The Company has two gas storage facilities with the gas in storage stated at average cost, a portion of which is carried as current inventory as discussed above in "Inventory." The storage facility owned by the Natural Gas Distribution segment is used for supply to the utility's customers. The cost of the gas withdrawn from this storage facility is passed on to the consumer. The E&P segment primarily uses its storage facility to supplement production in meeting contractual commitments and records revenue on storage withdrawals when such gas is sold. The carrying value of this gas in storage is assessed based on current and future market prices for gas that the Company expects to realize.

Capitalized Interest. Interest is capitalized on the cost of unevaluated gas and oil properties excluded from amortization, investments in gathering systems construction until these assets are placed in service and on drilling rigs during their construction phase. In accordance with established utility regulatory practice, an allowance for funds used during construction of major projects is capitalized and amortized over the estimated lives of the related facilities.

Asset Retirement Obligations. Statement of Financial Accounting Standards No. 143 "Accounting for Asset Retirement Obligations" (FAS 143) was adopted by the Company on January 1, 2003. FAS 143 requires that the fair value of a liability for an asset retirement obligation be recognized in the period in which it is incurred if a reasonable estimate of fair value can be made, and that the associated asset retirement costs be capitalized as part of the carrying amount of the long-lived asset. The Company owns natural gas and oil properties which require expenditures to plug and abandon the wells when reserves in the wells are depleted. These expenditures under FAS 143 are recorded in the period the liability is incurred (at the time the wells are drilled or acquired). The following table summarizes the Company's 2007 and 2006 activity related to asset retirement obligations:

	2007	2006
	(in thousands)	
Asset retirement obligation at January 1	**$ 10,545**	$ 9,229
Accretion of discount	**481**	401
Obligations incurred	**2,236**	1,152
Obligations settled	**(499)**	(645)
Revisions of estimates	**(649)**	408
Asset retirement obligation at December 31	**$ 12,114**	$ 10,545
Current liability	**720**	593
Long-term liability	**11,394**	9,952
Total asset retirement obligation at December 31	**$ 12,114**	$ 10,545

Gas Production Revenue and Imbalances

The E&P subsidiaries record gas sales using the entitlement method. The entitlement method requires revenue recognition of the Company's revenue interest share of gas production from properties in which gas sales are disproportionately allocated to owners because of marketing or other contractual arrangements. At December 31, 2007, the Company had overproduction of 1.2 Bcf valued at $3.5 million and underproduction of 1.6 Bcf valued at $4.7 million. At December 31, 2006, the Company had overproduction of 1.2 Bcf valued at $3.5 million and underproduction of 1.5 Bcf valued at $4.4 million.

Gas Distribution Revenues and Receivables

Customer receivables arise from the sale or transportation of gas by the Company's gas distribution subsidiary. The Company's gas distribution customers are located in northern Arkansas and represent a diversified base of residential, commercial and industrial users. The Company records gas distribution revenues on an accrual basis, as gas volumes are used, to provide a proper matching of revenues with expenses.

The gas distribution subsidiary's rate schedules include purchased gas adjustment clauses whereby the actual cost of purchased gas above or below the projected level included in the rates is permitted to be billed or is required to be credited to customers. Each month, the difference between actual costs of purchased gas and gas costs recovered from customers is deferred. The deferred differences are billed or credited, as appropriate, to customers in subsequent months. Rate schedules include a weather normalization clause to lessen the impact of revenue increases and decreases which might result from weather variations during the winter heating season. The pass-through of gas costs to customers is not affected by this normalization clause.

In July 2007, the APSC approved a rate increase for our utility segment totaling $5.8 million annually, exclusive of costs to be recovered through the utility's purchase gas adjustment clause. The rate increase became effective for billings rendered on or after August 1, 2007. The APSC order provided for an allowed return on equity of 9.5% and an assumed capital structure of 55% debt and 45% equity.

Income Taxes

Deferred income taxes are provided to recognize the income tax effect of reporting certain transactions in different years for income tax and financial reporting purposes. The Company's net operating loss carryforward at December 31, 2007, was $717.6 million with expiration dates in 2020 through 2027. Approximately $62.6 million of the net operating loss carryforward relates to the exercise of stock options, the benefit of which will be credited to equity when realized. The net operating loss carryforward can be used to reduce tax gains that will be realized on the sales of the Natural Gas Distribution segment and any potential sales of E&P assets. See Note 4 for additional information.

Derivative Financial Instruments

The Company uses derivative financial instruments to manage defined commodity price risks and interest rate risks and does not use them for speculative trading purposes. The Company uses commodity swaps and options contracts to hedge sales and purchases of natural gas and sales of crude oil. Gains and losses resulting from the settlement of hedge contracts have been recognized in gas and oil sales in the statements of operations when the contracts expire and the related physical transactions of the commodity hedged are recognized. Changes in fair value of derivative instruments designated as cash flow hedges are reported in other comprehensive income (loss) to the extent that they are effective in offsetting the changes in the cash flows of the hedged item. In contrast, gains and losses from the ineffective portion of swaps and option contacts as well as those contracts that do not qualify for hedge accounting treatment are recognized currently in gas and oil sales. See Note 9 for a discussion of the Company's hedging activities and the effects of FAS 133.

Earnings Per Share

Basic earnings per common share is computed by dividing net income by the weighted average number of common shares outstanding during each year. The diluted earnings per share calculation adds to the weighted average number of common shares outstanding the incremental shares that would have been outstanding assuming the exercise of dilutive stock options and the vesting of unvested restricted shares of common stock. For the year ended December 31, 2007, 4,071,312 of the Company's outstanding options with an average exercise price of $7.39 were included in the calculation of diluted shares. Options for 205,125 shares were excluded from the calculation because they would have had an antidilutive effect. For the year ended December 31, 2006, 5,351,809 of the Company's outstanding options with an average exercise price of $3.57 were included in the calculation of diluted shares. Options for 440,431 shares were excluded from the calculation because they would have had an antidilutive effect. All of the Company's 7,126,465 outstanding options at December 31, 2005, with a weighted average exercise price of $4.34 were included in the calculation of diluted shares.

For the year ended December 31, 2007, the number of shares of restricted stock included in the calculation of diluted shares was 284,754. The calculation excluded 110,761 shares of restricted stock because they would have had an antidilutive effect. For the year ended December 31, 2006, the number of shares of restricted stock included in the calculation of diluted shares was 310,617. The calculation excluded 168,115 shares of restricted stock because they would have had an antidilutive effect. All of the Company's 707,142 non-vested restricted stock shares for 2005 were included in the calculation.

Accounting for Stock-Based Compensation

In December 2004, the FASB issued Statement on Financial Accounting Standards No. 123R "Share-Based Payment" (FAS 123R). FAS 123R requires that companies recognize compensation expense equal to the fair value of stock options or other share based payments. The Company adopted this standard during the year ended December 31, 2006, using the modified prospective method. See Note 10 for further discussion of the Company's stock based compensation.

Accounting for Defined Benefit Pension and Other Postretirement Plans

In September 2006, Statement of Financial Accounting Standards No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans" (FAS 158) was issued. FAS 158 requires, among other things, the recognition of the funded status of each defined pension benefit plan, retiree health care and other postretirement benefit plans and postemployment benefit plans on the balance sheet. The Company adopted FAS 158 as of December 31, 2006. See Note 5 for additional information.

(2) ASSETS HELD FOR SALE

As discussed in Note 1 above, in November 2007, the Company entered into an agreement to sell all capital stock of AWG for $224 million plus working capital. Statement of Financial Accounting Standards No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets" (FAS 144), requires that long-lived assets or disposal groups to be sold should be classified as "held for sale" in the period in which certain criteria are met. Accordingly, the assets and liabilities of AWG have been presented as "held for sale" in the December 31, 2007 and 2006 balance sheets.

The following table presents the detail of assets and liabilities of AWG as of December 31, 2007, and 2006.

	2007	2006
	(in thousands)	
Current Assets:		
Cash	**$ 1,105**	$ 60
Accounts receivable	**29,826**	31,231
Inventory	**23,737**	26,755
Hedging asset – FAS 133	**2,387**	8,065
Other current assets	**1,822**	1,284
	$ 58,877	$ 67,395
Long-term assets, including property, plant and equipment, net of accumulated depreciation and amortization	**$ 143,234**	$ 139,523
Current Liabilities:		
Accounts payable	**$ 3,700**	$ 4,846
Taxes payable	**7,547**	5,817
Deferred gas purchases	**16,289**	10,580
Customer deposits	**7,551**	6,894
Hedging liability – FAS 133	**2,387**	8,065
Other current liabilities	**1,644**	1,530
	$ 39,118	$ 37,732
Long-term Liabilities:		
Deferred income taxes	**$ 15,066**	$ 15,821
Other long-term liabilities	**351**	800
	$ 15,417	$ 16,621

(3) DEBT

Debt balances as of December 31, 2007 and 2006 consisted of the following:

	2007	2006
	(in thousands)	
Current portion of long-term debt:		
7.15% Senior Notes due 2018	**$ 1,200**	$ 1,200
Long-term:		
Variable rate (5.87% at December 31, 2007) unsecured revolving credit facility	**842,200**	—
7.625% Senior Notes due 2027, putable at the holders' option in 2009	**60,000**	60,000
7.21% Senior Notes due 2017	**40,000**	40,000
7.15% Senior Notes due 2018	**35,400**	36,600
Total long-term debt	**977,600**	136,600
Total debt	**$ 978,800**	$ 137,800

On October 12, 2007, the Company amended its unsecured revolving credit facility increasing the borrowing capacity to $1.0 billion. The amendment also provides that the amount available under the revolving credit facility may be increased to $1.25 billion at any time upon the Company's agreement with its existing or additional lenders. The interest rate on the amended credit facility is calculated based upon the Company's debt rating and is currently 87.5 basis points over the current London Interbank Offered Rate (LIBOR). The revolving credit facility is currently guaranteed by the Company's subsidiaries, Southwestern Energy Production Company, SEECO, Inc. and Southwestern Energy Services Company and requires additional subsidiary guarantors if certain guaranty coverage levels are not satisfied. The revolving credit facility also contains covenants which impose certain restrictions on the Company. Under the credit agreement, the Company may not issue total debt in excess of 60% of its total capital, must maintain a certain level of stockholders' equity, and must maintain a ratio of earnings before interest, taxes, depreciation and amortization (EBITDA) to interest expense of 3.5 or above. There are also restrictions on the ability of the Company's subsidiaries to incur debt. At December 31, 2007, the Company's capital structure consisted of 37% debt and 63% equity and it was in compliance with the covenants of its debt agreements.

The 7.15% senior notes were assumed by the Company in 2006 in connection with the sale of the Company's general partnership interest in NOARK. The Company had previously guaranteed the notes.

The 7.625% senior notes are putable at the holders' option in 2009. Other than the 7.625% senior notes, aggregate maturities of long-term debt for each of the years ending December 31, 2008 through 2012 are $1.2 million per year for the 7.15% senior notes. Total interest payments were $36.0 million in 2007, $10.8 million in 2006 and $20.3 million in 2005.

On January 16, 2008, the Company issued $600 million of 7.5% Senior Notes due 2018 in a private placement. The 7.5% notes are redeemable at the Company's election, in whole or in part, at any time at a redemption price equal to the greater of: (1) 100% of the principal amount of the notes to be redeemed then outstanding; and (2) the sum of the present values of the remaining scheduled payments of principal and interest on the notes to be redeemed (not including any portion of such payments of interest accrued to the date of redemption) discounted to the redemption date on a semiannual basis as determined in accordance with the indenture, plus 50 basis points, plus, in either of such cases, accrued and unpaid interest to the date of redemption on the notes to be redeemed. In addition, if the Company undergoes a "change of control," as defined, holders of the 7.5% notes will have the option to require the Company 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. The indentures governing the Company's notes contain covenants that, among other things, restrict the ability of the Company and/or its subsidiaries to incur liens, to engage in sale and leaseback transactions and to merge, consolidate or sell assets. The 7.5% notes are currently guaranteed by the Company's subsidiaries, SEECO, Inc., Southwestern Energy Production Company and Southwestern Energy Services, which guarantees may be unconditionally released in certain circumstances.

(4) INCOME TAXES

The provision for income taxes included the following components:

	2007	2006	2005
		(in thousands)	
Federal:			
Current	$ —	$ —	$ —
Deferred	**120,200**	90,186	79,845
State:			
Current	—	—	—
Deferred	**15,757**	9,320	6,698
Investment tax credit amortization	**(102)**	(107)	(112)
Provision for income taxes	**$ 135,855**	$ 99,399	$ 86,431

The provision for income taxes was an effective rate of 38.1% in 2007, 37.9% in 2006 and 36.9% in 2005. The following reconciles the provision for income taxes included in the consolidated statements of operations with the provision which would result from application of the statutory federal tax rate to pre-tax financial income:

	2007	2006	2005
		(in thousands)	
Expected provision at federal statutory rate of 35%	**$ 124,960**	$ 91,712	$ 81,967
Increase resulting from:			
State income taxes, net of federal income tax effect	**10,242**	6,058	4,354
Other	**653**	1,629	110
Provision for income taxes	**$ 135,855**	$ 99,399	$ 86,431

The components of the Company's net deferred tax liability as of December 31, 2007 and 2006 were as follows:

	2007	2006
	(in thousands)	
Deferred tax liabilities:		
Differences between book and tax basis of property	**$ 763,903**	$ 500,386
Stored gas	**7,448**	4,558
Cash flow hedges - FAS 133	**17,043**	24,906
Other	**7,903**	7,470
	796,297	537,320
Deferred tax assets:		
Accrued compensation	**8,691**	6,795
Alternative minimum tax credit carryforward	**3,026**	3,026
Accrued pension costs	**6,040**	3,702
Book over tax basis in partnerships	**1,247**	1,247
Asset retirement obligations - FAS 143	**3,728**	3,728
Net operating loss carryforward	**252,122**	125,438
Other	**6,792**	4,322
	281,646	148,258
Net deferred tax liability	**$ 514,651**	$ 389,062

The net deferred tax liability at December 31, 2007, consisted of a current deferred income tax liability of $20.9 million and long-term deferred income tax liabilities of $494.3 million including unamortized deferred investment tax credits of $0.5 million. There were no income tax payments made in 2007 and 2005. In 2006, the Company paid $6,000 in income taxes. The Company's net operating loss carryforward at December 31, 2007, was $717.6 million with expiration dates in 2020 through 2027. The Company also had an alternative minimum tax credit carryforward of $3.0 million and a statutory depletion carryforward of $8.2 million at December 31, 2007.

Deferred tax assets relating to tax benefits of employee stock option grants have been reduced to reflect exercises in 2007 and 2006. Some exercises resulted in tax deductions in excess of previously recorded benefits based on the option value at the time of the grant (“windfalls”). Although these additional tax benefits or “windfalls” are reflected in net operating loss carryforwards, pursuant to FAS 123R, the additional tax benefit associated with the windfall is not recognized until the deduction reduces tax payable. Accordingly, since the tax benefit does not reduce our current taxes payable in 2007 due to net operating loss carryforwards, these “windfall” tax benefits are not reflected in our net operating losses in deferred tax assets for 2007. Windfalls included in net operating loss carryforwards but not reflected in deferred tax assets for 2007 are $62.6 million. There were no windfalls excluded from deferred tax assets in 2006.

(5) PENSION PLAN AND OTHER POSTRETIREMENT BENEFITS

Prior to January 1, 1998, the Company maintained a traditional defined benefit plan with benefits payable based upon average final compensation and years of service. Effective January 1, 1998, the Company amended its pension plan to become a “cash balance” plan on a prospective basis for its non-bargaining employees. A cash balance plan provides benefits based upon a fixed percentage of an employee’s annual compensation. The Company’s funding policy is to contribute amounts which are actuarially determined to provide the plans with sufficient assets to meet future benefit payment requirements and which are tax deductible.

The postretirement benefit plans provide contributory health care and life insurance benefits. Employees become eligible for these benefits if they meet age and service requirements. Generally, the benefits paid are a stated percentage of medical expenses reduced by deductibles and other coverages. The Company has established trusts to partially fund its postretirement benefit obligations.

The Company applies Statement of Financial Accounting Standards No. 132, “Employers’ Disclosures about Pensions and Other Postretirement Benefits” (FAS 132). Substantially all employees are covered by the Company’s defined benefit pension and postretirement benefit plans. Additionally, the Company applies Statement of Financial Accounting Standards No. 158, “Employers’ Accounting for Defined Benefit Pension and Other Postretirement Plans” (FAS 158). FAS 158 requires, among other things, the recognition of the funded status of each defined pension benefit plan, retiree health care and other postretirement benefit plans and postemployment benefit plans on the balance sheet. Each overfunded plan is recognized as an asset and each underfunded plan is recognized as a liability. The initial impact of the standard due to unrecognized prior service costs or credits and net actuarial gains or losses as well as subsequent changes in the funded status was recognized as a component of accumulated comprehensive loss in stockholders’ equity. Additional minimum pension liabilities (AML) and related intangible assets were also derecognized upon adoption of the new standard. FAS 158 was adopted by the Company as of December 31, 2006.

The amounts in accumulated other comprehensive loss that are expected to be recognized as components of net periodic benefit cost (credit) during the next fiscal year are $0.5 million for prior service costs, $0.5 million net loss and $0.1 million for transition obligation costs.

The following provides a reconciliation of the changes in the plans’ benefit obligations, fair value of assets, and funded status as of December 31, 2007 and 2006:

	Pension Benefits		Other Postretirement Benefits	
	2007	2006	**2007**	2006
	(in thousands)			
Change in benefit obligations:				
Benefit obligation at January 1	**$ 70,863**	$ 71,854	**$ 3,694**	$ 4,022
Service cost	**3,983**	3,011	**418**	271
Interest cost	**4,243**	3,881	**215**	189
Participant contributions	**—**	—	**108**	116
Actuarial loss/(gain)	**4,706**	(2,588)	**129**	(578)
Benefits paid	**(4,889)**	(5,683)	**(303)**	(326)
Plan amendments	**487**	388	**—**	—
Benefit obligation at December 31	**$ 79,393**	$ 70,863	**$ 4,261**	$ 3,694

	Pension Benefits		Other Postretirement Benefits	
	2007	2006	**2007**	2006
	(in thousands)			
Change in plan assets:				
Fair value of plan assets at January 1	**$ 59,166**	$ 55,932	**$ 1,617**	$ 1,379
Actual return on plan assets	**6,334**	5,504	**84**	94
Employer contributions	**6,514**	3,413	**405**	354
Participant contributions	**—**	—	**108**	116
Benefit payments	**(4,889)**	(5,683)	**(303)**	(326)
Fair value of plan assets at December 31	**$ 67,125**	$ 59,166	**$ 1,911**	$ 1,617

The Company uses a December 31 measurement date for all of its plans. At December 31, 2007, the Company recorded liabilities of $12.3 million and $2.3 million related to its pension and other postretirement benefit plans, respectively. At December 31, 2006, the Company recorded liabilities of $11.7 million and $2.1 million related to its pension and other postretirement benefit plans, respectively. These amounts represent the difference between the fair value of the plans' assets and projected benefit obligations for the pension liability, and the difference between the fair value of the plans' assets and accumulated postretirement benefit obligations for the postretirement benefits liability.

The change in accumulated other comprehensive loss related to the pension plans was a loss of $2.5 million ($1.4 million after tax) for the year ended December 31, 2007 and a loss of $6.5 million ($4.1 million after tax) for the year ended December 31, 2006. The change in accumulated other comprehensive loss related to the other postretirement benefit plans was negligible for the year ended December 31, 2007 and a loss of $1.2 million ($0.8 million after tax) for the year ended December 31, 2006. Included in accumulated other comprehensive loss at December 31, 2007 and 2006 was an $18.2 million loss ($11.3 million net of tax) and a $15.7 million loss ($9.9 million net of tax), respectively, related to the Company's pension and other postretirement benefit plans.

The Company's pension plans have an accumulated benefit obligation in excess of plan assets as of December 31, 2007 and 2006 as follows:

	2007	2006
	(in thousands)	
Projected benefit obligation	**$79,393**	$70,863
Accumulated benefit obligation	**71,104**	63,347
Fair value of plan assets	**67,125**	59,166

Net periodic pension and other postretirement benefit costs include the following components for 2007, 2006 and 2005:

	Pension Benefits			Other Postretirement Benefits		
	2007	2006	2005	**2007**	2006	2005
	(in thousands)					
Service cost	**$ 3,983**	$ 3,011	$ 2,523	**$ 419**	$ 271	$ 172
Interest cost	**4,243**	3,881	3,764	**215**	189	201
Expected return on plan assets	**(4,559)**	(4,578)	(4,776)	**(81)**	(69)	(56)
Amortization of transition obligation	**—**	—	—	**86**	86	86
Recognized net actuarial loss	**460**	759	326	**21**	34	41
Amortization of prior service cost	**475**	436	440	**—**	—	—
	$ 4,602	$ 3,509	$ 2,277	**$ 660**	$ 511	$ 444

Amounts recognized in other comprehensive income for the year ended December 31, 2007 were as follows:

	Pension Benefits	Other Postretirement Benefits
	(in thousands)	
Net actuarial loss arising during the year	$(3,417)	$ (125)
Recognized net actuarial loss	460	21
Amortization of prior service cost	475	—
Net transition asset	—	86
Tax effect	1,117	19
	$(1,365)	$ 1

The weighted average assumptions used in the measurement of the Company's benefit obligations at December 31, 2007 and 2006 are as follows:

	Pension Benefits		Other Postretirement Benefits	
	2007	2006	**2007**	2006
Discount rate	**6.00%**	6.00%	**6.00%**	6.00%
Rate of compensation increase	**4.00%**	4.00%	**n/a**	n/a

The weighted average assumptions used in the measurement of the Company's net periodic benefit cost for 2007, 2006 and 2005 are as follows:

	Pension Benefits			Other Postretirement Benefits		
	2007	2006	2005	**2007**	2006	2005
Discount rate	**6.00%**	5.50%	6.00%	**6.00%**	5.50%	6.00%
Expected return on plan assets	**8.00%**	8.25%	9.00%	**5.00%**	5.00%	5.00%
Rate of compensation increase	**4.00%**	4.00%	4.00%	**n/a**	n/a	n/a

The expected return on plan assets for the various benefit plans is based upon a review of the historical returns experienced, combined with the future expected returns based upon the asset allocation strategy employed. The plans seek to achieve an adequate return to fund the obligations in a manner consistent with the federal standards of ERISA and with a prudent level of diversification.

For measurement purposes, the following trend rates were assumed for 2007 and 2006:

	2007	2006
Health care cost trend assumed for next year	**9%**	9%
Rate to which the cost trend is assumed to decline	**5%**	5%
Year that the rate reaches the ultimate trend rate	**2013**	2012

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

	1% Increase	1% Decrease
	(in thousands)	
Effect on the total service and interest cost components	$ 83	$ (71)
Effect on postretirement benefit obligation	$ 460	$ (401)

The Company's pension plan weighted-average asset allocations at December 31, 2007 and 2006, by asset category, are as follows:

	2007	2006
Asset category:		
Equity securities	**55%**	59%
Debt securities	**39%**	37%
Cash equivalents	**6%**	4%
Total	**100%**	100%

Assets of the postretirement benefit plans were invested 100% in debt securities for 2007 and 2006.

The investment objective of the benefit plans is to ensure, over the long-term life of the plans, an adequate pool of assets to support the benefit obligations to participants, retirees and beneficiaries. As of December 31, 2007, the defined benefit pension plan had a diversified asset allocation strategy of 55% to 75% and a target of 60% for equity securities and 35% to 45% and a target of 40% for debt (fixed income) securities. Within the equity allocation, the plan invests in small cap, international, large cap growth, large cap value and large cap core securities. Plan assets are periodically balanced whenever the allocation to any asset class falls outside of the specified range.

In 2007, the Company contributed $6.5 million to its pension plans and $0.4 million to its other postretirement benefit plans. The Company expects to contribute $7.5 million to its pension plans and $0.4 million to its other postretirement benefit plans in 2008. No plan assets are expected to be returned to the Company during the next twelve months.

The following benefit payments, which reflect expected future service, as appropriate, are expected to be paid:

	Pension Benefits	Other Benefits
	(in thousands)	
2008	$ 3,707	$ 207
2009	$ 3,630	$ 181
2010	$ 6,530	$ 202
2011	$ 6,937	$ 254
2012	$ 5,071	$ 301
Years 2013-2017	$41,238	$2,484

The Company also maintains a non-qualified defined contribution supplemental retirement savings plan for certain key employees whereby participants may elect to defer and contribute a portion of their compensation, as permitted by the plan. The Company maintains supplemental retirement savings plan assets that are held in a Rabbi Trust and are accounted for in accordance with EITF Issue No. 97-14, "Accounting for Deferred Compensation Arrangements where Accounts are Held in a Rabbi Trust and Invested." Shares of the Company's common stock purchased under a non-qualified deferred compensation arrangement are held in a Rabbi Trust and are presented as treasury stock. As of December 31, 2007, 111,387 shares were accounted for as treasury stock.

(6) NATURAL GAS AND OIL PRODUCING ACTIVITIES (UNAUDITED)

All of the Company's gas and oil properties are located in the United States. The table below sets forth the results of operations from gas and oil producing activities:

	2007	2006	2005
		(in thousands)	
Sales	**$ 795,944**	$ 491,545	$ 403,234
Production (lifting) costs	**(97,645)**	(68,479)	(50,949)
Depreciation, depletion and amortization	**(281,910)**	(143,101)	(88,902)
	416,389	279,965	263,383
Income tax expense	**(157,584)**	(105,227)	(96,651)
Results of operations	**$ 258,805**	$ 174,738	$ 166,732

The results of operations shown above exclude general and administrative expenses and interest costs. Income tax expense is calculated by applying the statutory tax rates to the revenues less costs, including depreciation, depletion and amortization, and after giving effect to permanent differences and tax credits.

The table below sets forth capitalized costs incurred in gas and oil property acquisition, exploration and development activities during 2007, 2006 and 2005:

	2007	2006	2005
		(in thousands)	
Proved property acquisition costs	**$ 1,540**	$ 18,697	$ 75
Unproved property acquisition costs	**72,292**	55,032	55,652
Exploration costs	**527,456**	231,771	44,416
Development costs	**769,588**	453,956	313,759
Capitalized costs incurred	**$ 1,370,876**	$ 759,456	$ 413,902
Full cost pool amortization per Mcf equivalent	**$ 2.41**	$ 1.90	$ 1.42

Capitalized interest is included as part of the cost of natural gas and oil properties. The Company capitalized $13.8 million, $10.3 million and $5.0 million during 2007, 2006 and 2005, respectively, based on the Company's weighted average cost of borrowings used to finance the expenditures. The increases in capitalized interest since 2005 reflect an increase in the Company's unevaluated costs primarily related to lease acquisition and drilling activities.

In addition to capitalized interest, the Company also capitalized internal costs of $58.9 million, $44.1 million and $26.4 million during 2007, 2006 and 2005, respectively. These internal costs were directly related to acquisition, exploration and development activities and are included as part of the cost of natural gas and oil properties. The increases in internal costs capitalized since 2004 have resulted from the addition of personnel and related costs in Southwestern's exploration and development segment.

The table of capitalized costs incurred above does not include amounts incurred for the acquisition of drilling rigs and related equipment, most of which has been sold and leased back.

The following table shows the capitalized costs of gas and oil properties and the related accumulated depreciation, depletion and amortization at December 31, 2007 and 2006:

	2007	2006
	(in thousands)	
Proved properties	**$ 3,648,029**	$ 2,484,600
Unproved properties	**372,419**	166,827
Total capitalized costs	**4,020,448**	2,651,427
Less: Accumulated depreciation, depletion and amortization	**1,158,387**	883,100
Net capitalized costs	**$ 2,862,061**	$ 1,768,327

The table below sets forth the composition of net unevaluated costs excluded from amortization as of December 31, 2007. Of the total at December 31, 2007, approximately $92.6 million is related to undeveloped leasehold costs in the Company's Fayetteville Shale play, approximately $89.6 million is related to unevaluated seismic costs in the Fayetteville Shale play and approximately $72.3 million represents costs of wells in progress. The remaining costs excluded from amortization are related to properties which are not individually significant and on which the evaluation process has not been completed. Costs related to wells in progress will be included in the amortization computation in 2008. The timing and amount of the Fayetteville Shale play leasehold and seismic costs included in the amortization computation will depend on the location and timing of drilling wells to further develop the play. The Company is, therefore, unable to estimate when these costs will be included in the amortization computation.

	2007	2006	2005	Prior	**Total**
			(in thousands)		
Property acquisition costs	$ 72,234	$38,111	$40,248	$24,266	**$ 174,859**
Exploration and development costs	155,530	10,130	4,142	104	**169,906**
Capitalized interest	6,526	6,513	7,857	6,758	**27,654**
	$234,290	$54,754	$52,247	$31,128	**$ 372,419**

(7) NATURAL GAS AND OIL RESERVES (UNAUDITED)

The following table summarizes the changes in the Company's proved natural gas and oil reserves for 2007, 2006 and 2005:

	2007		2006		2005	
	Gas (MMcf)	**Oil (MBbls)**	Gas (MMcf)	Oil (MBbls)	Gas (MMcf)	Oil (MBbls)
Proved reserves, beginning of year	**978,934**	**7,898**	772,339	9,079	594,483	8,508
Revisions of previous estimates	**30,489**	**81**	(75,420)	(1,870)	(29,970)	(284)
Extensions, discoveries and other additions	**498,141**	**1,585**	352,734	1,645	264,683	1,669
Production	**(109,881)**	**(614)**	(68,133)	(698)	(56,758)	(705)
Acquisition of reserves in place	**204**	—	2,760	22	28	—
Disposition of reserves in place	**(1,031)**	**(38)**	(5,346)	(280)	(127)	(109)
Proved reserves, end of year	**1,396,856**	**8,912**	978,934	7,898	772,339	9,079
Proved developed reserves:						
Beginning of year	**623,870**	**6,994**	551,456	8,309	491,697	7,767
End of year	**880,278**	**7,269**	623,870	6,994	551,456	8,309

The "Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Natural Gas and Oil Reserves" (standardized measure) is a disclosure required by Statement of Financial Accounting Standards No. 69, "Disclosures About Oil and Gas Producing Activities" (FAS 69). The standardized measure does not purport to present the fair market value of a company's proved gas and oil reserves. In addition, there are uncertainties inherent in estimating quantities of proved reserves. The gas and oil reserve quantities owned by the Company were audited by the independent petroleum engineering firm of Netherland, Sewell & Associates, Inc.

Following is the standardized measure relating to proved gas and oil reserves at December 31, 2007, 2006 and 2005:

	2007	2006 (in thousands)	2005
Future cash inflows	**$ 9,380,172**	$ 5,662,436	$ 6,699,456
Future production costs	**(2,339,465)**	(1,752,482)	(1,656,084)
Future development costs	**(1,029,501)**	(737,292)	(329,528)
Future income tax expense	**(1,699,787)**	(794,388)	(1,387,765)
Future net cash flows	**4,311,419**	2,378,274	3,326,079
10% annual discount for estimated timing of cash flows	**(2,296,263)**	(1,335,519)	(1,905,268)
Standardized measure of discounted future net cash flows	**$ 2,015,156**	$ 1,042,755	$ 1,420,811

Under the standardized measure, future cash inflows were estimated by applying year-end prices, adjusted for known contractual changes, to the estimated future production of year-end proved reserves. Year-end market prices used for the standardized measures above were $6.80 per Mcf for gas and $92.50 per barrel for oil in 2007, $5.64 per Mcf for gas and $57.25 per barrel for oil in 2006, and $10.08 per Mcf for gas and $61.04 per barrel for oil in 2005. Future cash inflows were reduced by estimated future production and development costs based on year-end costs to determine pre-tax cash inflows. Future income taxes were computed by applying the year-end statutory rate, after consideration of permanent differences, to the excess of pre-tax cash inflows over the Company's tax basis in the associated proved gas and oil properties. Future net cash inflows after income taxes were discounted using a 10% annual discount rate to arrive at the standardized measure.

Following is an analysis of changes in the standardized measure during 2007, 2006 and 2005:

	2007	2006 (in thousands)	2005
Standardized measure, beginning of year	**$ 1,042,755**	$ 1,420,811	$ 892,308
Sales and transfers of gas and oil produced, net of production costs	**(698,299)**	(423,066)	(361,815)
Net changes in prices and production costs	**431,780**	(711,234)	582,247
Extensions, discoveries, and other additions, net of future production and development costs	**1,027,946**	381,924	546,523
Acquisition of reserves in place	**565**	5,106	58
Revisions of previous quantity estimates	**59,687**	(140,257)	(91,648)
Accretion of discount	**130,872**	198,641	121,837
Net change in income taxes	**(310,500)**	299,630	(239,539)
Changes in estimated future development costs	**102,760**	(69,450)	(248,322)
Previously estimated development costs incurred during the year	**134,149**	116,601	71,729
Changes in production rates (timing) and other	**93,441**	(35,951)	147,433
Standardized measure, end of year	**$ 2,015,156**	$ 1,042,755	$ 1,420,811

(8) INVESTMENT IN UNCONSOLIDATED PARTNERSHIP

In May 2006, the Company sold its 25% partnership interest in 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). The Company's share of pre-tax income or loss from operations related to the investment in NOARK was income of $0.9 million in 2006 and $1.6 million in 2005. Income from operations and the gain on the sale in 2006 were recorded in other income in the statements of operations.

(9) FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

Fair Value of Financial Instruments

The following methods and assumptions were used to estimate the fair value of each class of financial instruments for which it is practicable to estimate the value:

C*ash and Cash Equivalents, and Customer Deposits:* The carrying amount is a reasonable estimate of fair value.

Long-Term Debt: The fair value of the Company's long-term debt is estimated based on the expected current rates which would be offered to the Company for debt of the same maturities.

Commodity Hedges: The fair value of all hedging financial instruments is the amount at which they could be settled, based on quoted market prices, best estimates obtained from counterparties and an option pricing model, when necessary, for price option contracts.

The carrying amounts and estimated fair values of the Company's financial instruments as of December 31, 2007 and 2006 were as follows:

	2007		2006	
	Carrying Amount	**Fair Value**	Carrying Amount	Fair Value
	(in thousands)			
Cash and cash equivalents	**$ 1,832**	**$ 1,832**	$ 42,927	$ 42,927
Customer deposits	**$ 7,551**	**$ 7,551**	$ 6,894	$ 6,894
Total debt	**$ 978,800**	**$ 976,432**	$ 137,800	$ 141,704
Commodity hedges	**$ 45,994**	**$ 45,994**	$ 58,102	$ 58,102

Derivatives and Risk Management

The Company enters into various types of derivative instruments for a portion of its projected gas and oil sales to reduce its exposure to market price volatility for natural gas and oil. Statement of Financial Accounting Standards No. 133, "Accounting for Derivative Instruments and Hedging Activities" (FAS 133), as amended by FAS 137, FAS 138 and FAS 149, requires that all derivatives be recognized in the balance sheet as either an asset or liability measured at its fair value. Special accounting for qualifying hedges allows a derivative's gains and losses to offset related results on the hedged item in the income statement or as a component of other comprehensive income.

As of December 31, 2007, derivative instruments utilized by the Company included swaps, basis swaps and costless collars that are defined as follows:

- For fixed-price swaps, the Company receives a fixed price for the contract and pays a floating market price to the counterparty.
- For floating-price swaps, the Company receives a floating market price from the counterparty and pays a fixed price.
- Costless-collars contain a fixed floor price (put) and ceiling price (call). If the market price exceeds the call strike price or falls below the put strike price, the Company receives the fixed price and pays the market price. If the market price is between the call and the put strike price, no payments are due from either party.
- Basis swaps are arrangements that guarantee a price differential for natural gas from a specified delivery point. For basis protection swaps, the Company receives a payment from the counterparty if the price differential is greater than the stated terms of the contract and pays the counterparty if the price differential is less than the stated terms of the contract.
- Regulatory swaps are similar to that of floating price swaps but are used exclusively by the Natural Gas Distribution segment and are subject to accounting requirements set forth by the Arkansas Public Service Commission.

Substantially all of the Company's gas and oil derivative instruments that are not basis related are settled based upon NYMEX prices. Substantially all of the Company's derivative instruments that are basis related are settled based upon "Inside FERC" published prices for the particular locational basis that is traded. The estimated fair value of these derivative instruments are based upon various market factors.

At December 31, 2007, the Company recorded hedging assets of $71.5 million, hedging liabilities of $23.8 million as well as a regulatory asset and corresponding current liability of $2.4 million related to its utility gas purchase hedges. As of December 31, 2007, a net of tax gain to other comprehensive income (loss) of $24.6 million was recorded. The amount recorded in other comprehensive income (loss) will be relieved over time and taken to the income statement as the physical transactions being hedged occur. At December 31, 2006, the Company recorded hedging assets of $87.3 million, hedging liabilities of $20.7 million, a regulatory asset and corresponding current liability of $8.1 million related to its utility gas purchase hedges, and a net of tax gain to other comprehensive income (loss) of $41.4 million. The change in accumulated other comprehensive loss related to derivatives was a loss of $26.6 million ($16.8 million after tax) for the year ended December 31, 2007, a gain of $224.2 million ($141.2 million after tax) for the year ended December 31, 2006, and a loss of $128.6 million ($81.0 million after tax) for the year ended December 31, 2005. Assuming the market prices of futures as of December 31, 2007, remain unchanged, we would expect to transfer a gain of approximately $30.3 million from accumulated other comprehensive income to earnings during the next 12 months when the transactions actually close. All transactions hedged as of December 31, 2007, are expected to mature by December 31, 2009.

Gains or losses from derivative transactions are reflected as adjustments to gas and oil sales on the consolidated statements of operations. Gas and oil sales included a realized gain from settled contracts of $70.5 million in 2007, compared to a realized gain of $14.3 in 2006 and a realized loss of $85.8 million in 2005.

Cash Flow Hedges

For cash flow hedges, all derivative instruments are reported as either a hedging asset or hedging liability on the balance sheet and are measured at fair value. The reporting of gains and losses on derivative hedging instruments depends on whether the gains or losses are effective at offsetting changes in the cash flows of the hedged item. The effective portion of the gain or loss on the derivative hedging instrument is recorded in other comprehensive income (OCI) until recognized in earnings during the period that the hedged transaction takes place. The ineffective portion of the gains and losses from hedges is recognized in earnings immediately. The Company recorded a gain on the change in ineffectiveness of $1.1 million in 2007, compared to a gain of $20.2 million and a loss $9.4 million in 2006 and 2005, respectively.

For those contracts designated as cash flow hedges, the Company formally documents all relationships between the derivative instruments and the commodity being hedged, as well as its risk management objective and strategy for the particular derivative contracts as required by FAS 133.

Other Derivative Contracts

Although the Company’s basis swaps meet the objectives to manage our commodity price exposure, some of these trades do not qualify for hedge accounting under FAS 133. The basis swaps that do qualify for hedge accounting treatment are classified as “matched-basis” swaps. These matched-basis swaps have been combined with other derivative trades (i.e., costless collars and swaps) to form a single hedge where both trades are accounted for as a unit. The basis swap trades that have not been designated as hedges are recorded on the balance sheet at their fair values under hedging assets and hedging liabilities. All realized and unrealized gains and losses related to these contracts are recognized immediately in the statement of operations as a component of gas sales. As of December 31, 2007 and 2006, the fair values of the basis swaps that do not meet the requirements of FAS 133 hedges were a $0.7 million liability and a $6.7 million liability, respectively. The unrealized gain included in gas and oil sales for non-qualifying basis swaps was $6.0 million in 2007, compared to an unrealized loss of $25.8 million in 2006 and an unrealized gain of $19.1 million in 2005.

Hedge Position

At December 31, 2007, the Company had outstanding natural gas price swaps on total notional volumes of 55.7 Bcf in 2008 and 56.0 Bcf in 2009 for which the Company will receive fixed prices ranging from $7.29 to $9.98 per MMBtu. At December 31, 2007, the Company also had outstanding natural gas price swaps on total notional volumes of 0.7 Bcf in 2008 for which the Company will pay an average fixed price of $7.37 per Mcf. At December 31, 2007, the Company had 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, the Company 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. The Company’s price risk management activities increased revenues by $70.7 million in 2007, $8.7 million in 2006 and reduced revenues by $77.2 million in 2005.

The primary market risks related to the Company's derivative contracts are the volatility in commodity prices, basis differentials and interest rates. However, these market risks are offset by the gain or loss recognized upon the related sale or purchase of the natural gas or sale of oil that is hedged, and payment of variable rate interest. Credit risk relates to the risk of loss as a result of non-performance by the Company's 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 the Company has to each counterparty are periodically reviewed to ensure limited credit risk exposure.

(10) STOCK BASED COMPENSATION

The Southwestern Energy Company 2004 Stock Incentive Plan (2004 Plan) was adopted in February 2004 and approved by stockholders in May 2004. The 2004 Plan provides for the compensation of officers, key employees and eligible non-employee directors of the Company and its subsidiaries. The 2004 Plan replaced the Southwestern Energy Company 2000 Stock Incentive Plan (2000 Plan) and the Southwestern Energy Company 2002 Employee Stock Incentive Plan (2002 Plan) but did not affect prior awards under those plans which remained valid and some of which are still outstanding. The awards under the prior plans have been adjusted for the two-for-one stock splits in 2005 as permitted under such plans. The Company also has awards outstanding under the Southwestern Energy Company 1993 Stock Incentive Plan (1993 Plan) and the Southwestern Energy Company 1993 Stock Incentive Plan for Outside Directors (1993 Director Plan).

The 2004 Plan provides for grants of options, stock appreciation rights, and shares of restricted stock and restricted stock units to employees, officers and directors that in the aggregate do not exceed 8,400,000 shares (as adjusted for the stock splits). The types of incentives that may be awarded are comprehensive and are intended to enable the Company's board of directors to structure the most appropriate incentives and to address changes in income tax laws which may be enacted over the term of the 2004 Plan.

As initially adopted, the 2000 Plan provided for the grant of options, stock appreciation rights, shares of phantom stock, and shares of restricted stock to employees, officers and directors that in the aggregate did not exceed 1,250,000 shares and an annual award to each non-employee director with respect to 8,000 shares of common stock. The 2002 Plan provided for grants of options, stock appreciation rights, shares of phantom stock and shares of restricted stock that in the aggregate did not exceed 1,200,000 shares to employees who are not officers or directors of the Company under provisions of Section 16 of the Securities Exchange Act of 1934, as amended.

The 1993 Plan, as amended, provided for the compensation of officers and key employees of the Company through grants of options, shares of restricted stock, and stock bonuses that in the aggregate did not exceed 1,700,000 shares, the grant of stand-alone stock appreciation rights (SARs), shares of phantom stock and cash awards, the shares related to which in the aggregate did not exceed 1,700,000 shares, and the grant of limited and tandem SARs (all terms as defined in the 1993 Plan). The Company has also awarded stock option grants outside the various stock incentive plans to certain non-officer employees and to certain officers at the time of their hire. As adopted, the 1993 Director Plan provided for annual stock option grants of 12,000 shares (with 12,000 limited SARs to each non-employee director up to an aggregate of 240,000 shares).

On January 1, 2006, the Company adopted FAS 123R, which requires companies to measure the cost of employee services received in exchange for an award of equity instruments based on the grant date fair value of the award. The Company has elected to use the modified prospective application method such that FAS 123R applies to new awards, the unvested portion of existing awards and to awards modified, repurchased or canceled after the effective date. The Company has equity incentive plans that provide for the issuance of stock options and restricted stock. All options are issued at fair market value at the date of grant and expire seven years from the date of grant for awards under the 2004 Plan and ten years from the date of grant for awards under all other plans. Generally, stock options granted to employees and directors vest ratably over three to four years from the grant date. The Company issues shares of restricted stock to employees and directors which generally vest over four years. The Company recognizes stock-based compensation expense on a straight-line basis over the requisite service period of the individual grants with the exception of awards granted to participants who have reached retirement age or will reach retirement age during the vesting period. In the fourth quarter of 2005, the Board of Directors prospectively revised the vesting for restricted stock and stock options granted to participants on or after December 8, 2005, under the 2004 Plan to immediately accelerate vesting upon death, disability or retirement (subject to a minimum of five years of service). This change did not affect awards issued prior to December 8, 2005.

Prior to January 1, 2006, the Company accounted for its long-term equity incentive plans under the intrinsic value method described in APB Opinion No. 25, “Accounting for Stock Issued to Employees” and related interpretations (APB 25). The Company, applying the intrinsic value method, did not record stock-based compensation cost for stock options because the exercise price of the stock options equaled the market price of the underlying stock at the date of grant.

Stock Options

For the years ended December 31, 2007 and 2006, the Company recognized compensation costs of $3.4 million and $3.6 million, respectively, related to stock options subject to FAS 123R. Of these amounts, $0.7 million for 2007 and $0.5 million for 2006 were directly related to the acquisition, exploration and development activities for the Company’s gas and oil properties and were capitalized into the full cost pool. The remaining costs were recorded in general and administrative expenses. Under the provisions of FAS 123R, the Company recorded a deferred tax benefit of $0.6 million and $1.1 million related to stock options for the years ended December 31, 2007 and 2006, respectively. Unrecognized compensation costs of $7.4 million at December 31, 2007, related to stock options not yet vested are expected to be recognized over future periods. That cost is expected to be recognized over a weighted-average period of 2.2 years.

The fair value of stock options is estimated on the date of the grant using a Black-Scholes valuation model that uses the weighted average assumptions noted in the following table. Expected volatility is based on historical volatility of the Company’s common stock and other factors. The Company uses historical data on exercise of stock options, post vesting forfeitures and other factors to estimate the expected term of the share-based payments granted. The risk free interest rate is based on the U.S. Treasury yield curve in effect at the time of grant.

Assumptions	2007	2006	2005
Risk-free interest rate	3.5%	4.5%	4.4%
Expected dividend yield	—	—	—
Expected volatility	41.3%	42.7%	40.6%
Expected term	5 years	5 years	4 years

The Company may utilize treasury shares, if available, or use authorized but unissued shares when a stock option is exercised or when restricted stock is granted.

Prior to the adoption of FAS 123R on January 1, 2006, the Company accounted for its stock-based compensation plans under the recognition and measurement principles of APB 25. The following table illustrates the effect on net income and earnings per share for 2005 as if the fair value based method under FAS 123R had been applied to all outstanding vested and unvested awards for that period.

	For the year ended December 31, 2005 (in thousands, except share/per share amounts)
Net income, as reported	$ 147,760
Add back: Stock option based compensation expense included in reported net income, net of related tax effects	1,203
Deduct: Total stock-based employee compensation expense determined under fair value based method for all awards, net of related tax effects	(2,995)
Pro forma net income	$ 145,968
Earnings per share:	
Basic-as reported	$ 0.98
Basic-pro forma	0.97
Diluted-as reported	0.95
Diluted-pro forma	0.93

The following tables summarize stock option activity for the years 2007, 2006 and 2005 and provide information for options outstanding at December 31 of such years:

	2007		2006		2005	
	Number of Shares	**Weighted Average Exercise Price**	Number of Shares	Weighted Average Exercise Price	Number of Shares	Weighted Average Exercise Price
Options outstanding at January 1	**5,792,240**	**$ 6.19**	7,126,465	$ 4.34	8,884,512	$ 3.18
Granted	**203,220**	**54.25**	221,330	40.67	223,780	35.44
Exercised	**(1,707,023)**	**3.21**	(1,549,679)	2.50	(1,981,827)	2.66
Forfeited or expired	**(12,000)**	**20.91**	(5,876)	24.41	—	—
Options outstanding at December 31	**4,276,437**	**$ 9.63**	5,792,240	$ 6.19	7,126,465	$ 4.34

	Options Outstanding				Options Exercisable		
Range of Exercise Prices	Options Outstanding at Year End	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life (Years)	Aggregate Intrinsic Value (in thousands)	Options Exercisable at Year End	Weighted Average Exercise Price	Aggregate Intrinsic Value (in thousands)
$1.50 - $1.86	1,523,654	$ 1.75	2.6		1,523,654	$ 1.75	
$1.87 - $2.85	414,707	2.53	3.5		414,707	2.53	
$2.86 - $5.00	656,396	2.89	4.9		656,396	2.89	
$5.01 - $12.00	694,534	5.49	6.0		694,534	5.49	
$12.01 - $54.50	987,146	32.16	5.2		566,336	21.62	
	4,276,437	$ 9.63	4.2	$ 197,106	3,855,627	$ 5.62	$ 193,155

There were 203,220, 221,330 and 223,780 stock options granted during 2007, 2006 and 2005, respectively. The total intrinsic value of options exercised during 2007, 2006 and 2005 was $69.9 million, $49.0 million and $39.3 million, respectively.

Associated with the exercise of stock options for 2006 and 2005, the Company recorded a tax benefit of $14.6 million and $12.0 million, respectively. The tax benefit was recorded as an increase in additional paid-in capital.

Restricted Stock

For years ended December 31, 2007 and 2006, the Company recognized compensation costs of $4.6 million and $3.3 million, respectively, related to restricted stock grants. Of these amounts, $1.9 million in 2007 and $1.2 million in 2006 were directly related to the acquisition, exploration and development activities for the Company's gas and oil properties and were capitalized into the full cost pool. The remaining costs were recorded in general and administrative expenses. Under the provisions of FAS 123R, the Company recorded a deferred tax liability of $1.1 million and $1.6 million related to restricted stock for the years ended December 31, 2007 and 2006, respectively.

The Company granted 153,215 shares of restricted stock in 2007, 192,065 shares of restricted stock in 2006 and 132,065 shares of restricted stock in 2005. The fair values of the grants were $7.8 million for 2007, $7.6 million for 2006 and $4.3 million for 2005. In 2007, 24,943 shares of restricted stock were forfeited and 24,073 and 46,132 shares were forfeited in 2006 and 2005, respectively.

The following tables summarize restricted stock activity for the years 2007, 2006 and 2005 and provide information for restricted stock outstanding at December 31, 2007:

	2007		2006		2005	
	Number of Shares	**Weighted Average Grant Date Fair Value**	Number of Shares	Weighted Average Grant Date Fair Value	Number of Shares	Weighted Average Grant Date Fair Value
Unvested shares at January 1	**478,732**	**$ 25.30**	707,142	$ 11.14	1,281,031	$ 4.49
Granted	**153,215**	**50.65**	192,065	39.81	132,065	32.39
Vested	**(211,489)**	**16.11**	(396,402)	7.51	(659,822)	2.89
Forfeited	**(24,943)**	**29.16**	(24,073)	18.08	(46,132)	5.48
Unvested shares at December 31	**395,515**	**$ 39.79**	478,732	$ 25.30	707,142	$ 11.14

As of December 31, 2007, there was $13.0 million of total unrecognized compensation cost related to unvested shares that is expected to be recognized over a weighted-average period of 2.7 years. The total fair value of shares vested during 2007 was approximately $3.4 million.

(11) COMMON STOCK PURCHASE RIGHTS

In 1999, the Company's Common Share Purchase Rights Plan was amended and extended for an additional ten years. Under the terms of the amended plan, one common share purchase right is attached to each outstanding share of the Company's common stock. Each right entitles the holder to purchase one share of common stock at an exercise price of $10.00, subject to adjustment. These rights will become exercisable in the event that a person or group acquires or commences a tender or exchange offer for 15% or more of the Company's outstanding shares or the Board determines that a holder of 10% or more of the Company's outstanding shares presents a threat to the best interests of the Company. At no time will these rights have any voting power.

If any person or entity actually acquires 15% of the common stock (10% or more if the Board determines such acquiror is adverse), rightholders (other than the 15% or 10% stockholder) will be entitled to buy, at the right's then current exercise price, the Company's common stock with a market value of twice the exercise price. Similarly, if the Company is acquired in a merger or other business combination, each right will entitle its holder to purchase, at the right's then current exercise price, a number of the surviving company's common shares having a market value at that time of twice the right's exercise price.

The rights may be redeemed by the Board for $0.0025 per right or exchanged for shares of common stock on a one-for-one basis prior to the time that they become exercisable. In the event, however, that redemption of the rights is considered in connection with a proposed acquisition of the Company, the Board may redeem the rights only on the recommendation of its independent directors (non-management directors who are not affiliated with the proposed acquiror). These rights expire in 2009.

(12) CONTINGENCIES AND COMMITMENTS

Operating Commitments

The Company's E&P and Midstream Services segments have commitments to third parties for demand transportation charges. At December 31, 2007, future payments under non-cancelable demand charges for the Company's E&P and Midstream Services segments are approximately $22,379,000 in 2008, $4,822,000 in 2009, $1,495,000 in 2010 and $1,167,000 in 2011.

Additionally, the Company's gas distribution segment has entered into various non-cancelable agreements related to demand charges for the transportation and purchase of natural gas with third parties. These costs are recoverable from the utility's end-use customers. At December 31, 2007, future payments under these non-cancelable demand contracts are $9,767,000 in 2008, $9,640,000 in 2009, $10,026,000 in 2010, $10,413,000 in 2011, $10,380,000 in 2012 and $21,162,000 thereafter.

In December 2006, the Company entered into a precedent agreement pursuant to which it will contract for firm gas transportation services on two newly-proposed pipeline laterals and related facilities of Texas Gas Transmission, LLC (Texas Gas), a subsidiary of Boardwalk Pipeline Partners, LP, that are expected to be in service on January 1, 2009. The Company is obligated under the precedent agreement to enter into firm transportation agreements for the transport of up to

500,000 MMBtu per day on the Fayetteville Lateral and up to 400,000 MMBtu per day on the Greenville Lateral, with the option to increase such capacities at the Company's election. Upon execution and delivery of the firm transportation agreements contemplated by the precedent agreement, the Company's Midstream Services segment would have additional demand charges of $503.5 million that would be payable over the ten-year term of the agreements.

Southwestern leases drilling rigs and equipment for its E&P operations under leases that expire on January 1, 2015, and require aggregate annual rental payments of approximately $21.0 million. In accordance with the Company's accounting procedures, the lease payments for the drilling rigs, as well as other operating expenses for the Company's drilling operations, are capitalized to the full cost pool and are partially offset by billings to third-party working interest owners for their share of rig day-rate charges.

The Company has commitments for compression services related to its Midstream Services and E&P operations. At December 31, 2007, future minimum payments under these non-cancelable agreements are approximately $13,146,000 in 2008, $11,543,000 in 2009, $10,343,000 in 2010, $8,829,000 in 2011 and $3,344,000 in 2012. The Company also leases compressors, aircraft, office space and equipment under non-cancelable operating leases expiring through 2018. At December 31, 2007, future minimum payments under these non-cancelable leases accounted for as operating leases are approximately $10,801,000 in 2008, $10,864,000 in 2009, $8,803,000 in 2010, $7,987,000 in 2011, $8,131,000 in 2012 and $16,209,000 thereafter.

Environmental Risk

The Company is subject to laws and regulations relating to the protection of the environment. The Company's 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 the financial position or reported results of operations of the Company.

Litigation

The Company is subject to litigation and claims that have arisen in the ordinary course of business. The Company accrues for such items when a liability is both probable and the amount can be reasonably estimated. In the opinion of management, the results of such litigation and claims will not have a material effect on the results of operations or the financial position of the Company.

(13) SEGMENT INFORMATION

The Company applies Statement of Financial Accounting Standards No. 131, "Disclosures About Segments of an Enterprise and Related Information" (FAS 131). The Company's reportable business segments have been identified based on the differences in products or services provided. Revenues for the E&P segment are derived from the production and sale of natural gas and crude oil. The Midstream Services segment generates revenue through the marketing of both Company and third-party produced gas volumes and through gathering fees associated with the transportation of natural gas to market. Gathering revenues are expected to increase in the future depending upon the level of production from the Company's Fayetteville Shale properties. Revenues for the Natural Gas Distribution segment arise from the transportation and sale of natural gas at retail.

Summarized financial information for the Company's reportable segments is shown in the following table. The accounting policies of the segments are the same as those described in Note 1. Management evaluates the performance of its segments based on operating income, defined as operating revenues less operating costs and expenses. Income before income taxes is the sum of operating income, interest expense, other income (expense) and minority interest in partnership. The "Other" column includes items not related to the Company's reportable segments including real estate, the Company's former investment in the Ozark Gas Transmission system and corporate items.

	Exploration And Production	Midstream Services	Natural Gas Distribution	Other	Total
			(in thousands)		
2007					
Revenues from external customers	**$ 752,720**	**$ 328,609**	**$ 173,802**	**$ —**	**$ 1,255,131**
Intersegment revenues	**43,224**	**633,385**	**664**	**448**	**677,721**
Operating income	**358,079**	**13,236**	**9,960**	**191**	**381,466**
Interest and other income (loss)[1]	**382**	**(3)**	**(601)**	**3**	**(219)**
Depreciation, depletion and amortization expense	**281,910**	**5,524**	**6,319**	**161**	**293,914**
Interest expense[1]	**16,926**	**2,006**	**4,941**	**—**	**23,873**
Provision for income taxes[1]	**129,315**	**4,294**	**1,672**	**574**	**135,855**
Assets	**3,088,219**	**274,305**	**202,111**	**58,081[2]**	**3,622,716**
Capital investments[3]	**1,379,657**	**107,363**	**11,375**	**4,743**	**1,503,138**
2006					
Revenues from external customers	$ 452,887	$ 138,251	$ 171,974	$ —	$ 763,112
Intersegment revenues	38,658	336,956	233	448	376,295
Operating income	237,307	4,111	4,474	380	246,272
Interest and other income (loss)[1]	6,271	(581)	(415)	11,804	17,079
Depreciation, depletion and amortization expense	143,101	1,772	6,325	92	151,290
Interest expense[1]	508	—	171	—	679
Provision for income taxes[1]	91,276	554	1,698	5,871	99,399
Assets	1,965,247	112,027	206,919	94,876[2]	2,379,069
Capital investments[3]	861,041	48,660	11,232	21,474	942,407
2005					
Revenues from external customers	$ 365,384	$ 132,690	$ 177,810	$ 445	$ 676,329
Intersegment revenues	37,850	327,200	672	448	366,170
Operating income	234,759	5,684	4,911	566	245,920
Interest and other income (loss)[1]	3,401	—	(269)	1,652	4,784
Depreciation, depletion and amortization expense	88,902	303	6,907	99	96,211
Interest expense[1]	8,416	1,054	4,429	1,141	15,040
Provision for income taxes[1]	83,921	1,668	11	831	86,431
Assets	1,315,616	53,894	212,113	286,901[2]	1,868,524
Capital investments[3]	451,289	15,840	10,908	5,014	483,051

(1) Interest income, interest expense and the provision for income taxes by segment are an allocation of corporate amounts as cash equivalents, debt and income tax expense are incurred at the corporate level.

(2) Other assets include the Company's investment in cash equivalents for 2006 and 2005, the Company's equity investment in the operations of NOARK (see Note 8) for 2005, corporate assets not allocated to segments and assets for non-reportable segments.

(3) Capital investments include a reduction of $20.6 million for 2007 and increases of $88.9 million and $28.1 million for 2006 and 2005, respectively, related to the change in accrued expenditures between years.

Included in intersegment revenues of the Midstream Services segment are $559.5 million, $284.9 million and $290.9 million for 2007, 2006 and 2005, respectively, for marketing of the Company's E&P sales. Intersegment sales by the E&P segment and Midstream Services segment to the Natural Gas Distribution segment are priced in accordance with terms of existing contracts and current market conditions. Parent company assets include furniture and fixtures and prepaid debt and other costs. Parent company general and administrative costs, depreciation expense and taxes other than income are allocated to segments. All of the Company's operations are located within the United States.

(14) QUARTERLY RESULTS (UNAUDITED)

The following is a summary of the quarterly results of operations for the years ended December 31, 2007 and 2006:

	Mar 31	June 30	Sept 30	Dec 31
	(in thousands, except per share amounts)			
	2007			
Operating revenues	**$ 284,652**	**$ 270,082**	**$ 297,622**	**$ 402,775**
Operating income	**83,759**	**82,006**	**89,453**	**126,248**
Net income	**50,988**	**47,594**	**50,960**	**71,632**
Basic earnings per share	**0.30**	**0.28**	**0.30**	**0.42**
Diluted earnings per share	**0.30**	**0.28**	**0.30**	**0.41**
	2006			
Operating revenues	$ 226,702	$ 153,999	$ 168,394	$ 214,017
Operating income	89,804	48,294	53,118	55,056
Net income	58,395	37,004	33,477	33,760
Basic earnings per share	0.35	0.22	0.20	0.20
Diluted earnings per share	0.34	0.22	0.20	0.20

(15) NEW ACCOUNTING STANDARDS

During the first quarter of fiscal 2007, the Company adopted FASB Interpretation No. 48, “Accounting for Uncertainty in Income Taxes” (FIN 48). FIN 48 provides guidance for recognizing and measuring uncertain tax positions, as defined in SFAS No. 109, “Accounting for Income Taxes.” FIN 48 prescribes a threshold condition that a tax position must meet to be recognized in the financial statements. Guidance is also provided regarding de-recognition, classification and disclosure of these uncertain tax positions. FIN 48 was effective for fiscal years beginning after December 15, 2006. The adoption of FIN 48 had no material impact on the Company’s results of operations and financial condition. The income tax years 2004-2007 remain open to examination by the major taxing jurisdictions to which the Company is subject.

In September 2006, the Financial Accounting Standards Board issued SFAS 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. Prior to this statement, there were different definitions of fair value and limited guidance for applying those definitions in GAAP. In developing FAS 157, FASB considered the need for increased consistency and comparability in fair value measurements and for expanded disclosures about fair value measurements. This statement applies to other accounting pronouncements that require or permit fair value measurements. FAS 157 is effective for financial statements issued for fiscal years beginning after November 15, 2007. The Company will adopt FAS 157 in the first quarter of 2008 and will make additional required disclosures for financial instruments that are currently measured at fair value. In addition to required disclosures, FAS 157 also requires companies to evaluate current measurement techniques. The Company has not yet determined if any of its current fair value measurement methodology will change and, therefore, has not yet determined the impact FAS 157 may have on its results of operations or financial condition.

In February 2007, the Financial Accounting Standards Board issued SFAS 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 Company has not yet determined the impact FAS 159 may have on its results of operations or financial condition.

In December 2007, the Financial Accounting Standards Board issued SFAS 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 could impact the presentation of the Company’s balance sheet line item “Minority Interest” related to its Overton partnership (see Note 1 for discussion), but is expected to have no impact on the results of operations.

In December 2007, the Financial Accounting Standards Board issued SFAS No. 141(R), “Business Combinations” (FAS 141R). FAS 141R provides greater consistency in the accounting and financial reporting of business combinations. It requires the acquiring entity in a business combination to recognize all assets acquired and liabilities assumed in the transaction, establishes the acquisition-date fair value as the measurement objective for all assets acquired and liabilities assumed, and requires the acquirer to disclose the nature and financial effect of the business combination. FAS 141R is effective for fiscal years beginning after December 15, 2008. The Company has not yet determined the impact FAS 141R may have on its results of operations or financial condition.

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

None.

ITEM 9A. CONTROLS AND PROCEDURES

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 disclosure controls and procedures, as defined in Rule 13a-15(e) under the Securities Exchange Act of 1934 (the Exchange Act). Our disclosure controls and procedures are the controls and other procedures that we have designed to ensure that we record, process, accumulate and communicate information to our management, including our Chief Executive Officer and Chief Financial Officer, to allow timely decisions regarding required disclosures and submission within the time periods specified in the SEC's rules and forms. All internal control systems, no matter how well designed, have inherent limitations. Therefore, even those determined to be effective can provide only a level of reasonable assurance with respect to financial statement preparation and presentation. Based on the evaluation, our management, including our Chief Executive Officer and Chief Financial Officer, concluded that our disclosure controls and procedures were effective as of December 31, 2007, and provided a level of reasonable assurance with respect to financial statement preparation and presentation. There were no changes in our internal control over financial reporting during the three months ended December 31, 2007, that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Management's Report on Internal Control Over Financial Reporting is included on page 58 of this Form 10-K.

ITEM 9B. OTHER INFORMATION

There was no information required to be disclosed in a current report on Form 8-K during the fourth quarter of the fiscal year ended December 31, 2007, that was not reported on such form.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

The definitive Proxy Statement to holders of our common stock in connection with the solicitation of proxies to be used in voting at the Annual Meeting of Stockholders to be held on or about May 6, 2008, or the 2008 Proxy Statement, is hereby incorporated by reference for the purpose of providing information about the identification of our directors, and for discussion of our audit committee and our audit committee financial expert. We refer you to the sections "Proposal No. 1: Election of Directors" and "Share Ownership of Management, Directors and Nominees" in the 2008 Proxy Statement for information concerning our directors. We refer you to the section "Corporate Governance – Committees of the Board of Directors" for discussion of our audit committee and our audit committee financial expert. Information concerning our executive officers is presented in Part I of this Form 10-K. We refer you to the section "Section 16(a) Beneficial Ownership Reporting Compliance" for information relating to compliance with Section 16(a) of the Exchange Act.

The Company has adopted a code of ethics that applies to the Company's Chief Executive Officer, Chief Financial Officer and Chief Accounting Officer. The full text of such code of ethics has been posted on the Company's website at www.swn.com, and is available free of charge in print to any stockholder who requests it. Requests for copies should be addressed to the Secretary at 2350 N. Sam Houston Parkway East, Suite 125, Houston TX, 77032.

ITEM 11. EXECUTIVE COMPENSATION

The 2008 Proxy Statement is hereby incorporated by reference for the purpose of providing information about executive compensation, compensation committee interlocks and insider participation as well as the Compensation Committee Report. We refer you to the sections "Compensation Discussion & Analysis," "Executive Compensation," "Outside Director Compensation," "Compensation Committee Interlocks and Insider Participation" and "Compensation Committee Report" in the 2008 Proxy Statement.

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

The 2008 Proxy Statement is hereby incorporated by reference for the purpose of providing information about securities authorized for issuance under our equity compensation plans and security ownership of certain beneficial owners and our management. For information about our equity compensation plans, refer to "Equity Compensation Plans" in our 2008 Proxy Statement. Refer to the sections "Security Ownership of Certain Beneficial Owners" and "Share Ownership of Management, Directors and Nominees" in our 2008 Proxy Statement for information about security ownership of certain beneficial owners and our management and directors.

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

The 2008 Proxy Statement is hereby incorporated by reference for the purpose of providing information about certain relationships, related transactions and board independence. Refer to the sections "Transactions with Related Persons," "Share Ownership of Management, Directors and Nominees," and "Compensation Discussion and Analysis" for information about transactions with our executive officers, directors or management and to "Corporate Governance – Director Independence" and " – Committees of the Board of Directors" for information about director independence.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

The 2008 Proxy Statement is hereby incorporated by reference for the purpose of providing information about fees paid to the principal accountant and the audit committee's pre-approval policies and procedures. We refer you to the section "Relationship with Independent Registered Public Accounting Firm" in the 2008 Proxy Statement and to Exhibit A thereto for information concerning fees paid to our principal accountant and the audit committee's pre-approval policies and procedures and other required information.

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES

(a) (1) The consolidated financial statements of Southwestern Energy Company and its subsidiaries and the report of independent registered public accounting firm are included in Item 8 of this Form 10-K.

(2) The consolidated financial statement schedules have been omitted because they are not required under the related instructions, or are not applicable.

(3) The exhibits listed on the accompanying Exhibit Index are filed as part of, or incorporated by reference into, this Form 10-K.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused the report to be signed on its behalf by the undersigned, thereunto duly authorized.

SOUTHWESTERN ENERGY COMPANY

Dated: February 28, 2008

BY: /s/ Greg D. Kerley
Greg D. Kerley
Executive Vice President
and Chief Financial Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Registrant and in the capacities indicated on February 28, 2008.

/s/ Harold M. Korell Harold M. Korell	Director, Chairman, President and Chief Executive Officer
/s/ Greg D. Kerley Greg D. Kerley	Executive Vice President and Chief Financial Officer
/s/ Stanley T. Wilson Stanley T. Wilson	Controller and Chief Accounting Officer
/s/ Lewis E. Epley, Jr Lewis E. Epley, Jr	Director
/s/ Robert L. Howard Robert L. Howard	Director
/s/ Vello A. Kuuskraa Vello A. Kuuskraa	Director
/s/ Kenneth R. Mourton Kenneth R. Mourton	Director
/s/ Charles E. Scharlau Charles E. Scharlau	Director

EXHIBIT INDEX

Exhibit Number	Description
3.1	Certificate of Incorporation of Southwestern Energy Company. (Incorporated by reference to Exhibit 3.1 to the Registrant's Current Report on Form 8-K/A filed August 3, 2006)
3.2	Bylaws of Southwestern Energy Company. (Incorporated by reference to Exhibit 3.2 to the Registrant's Current Report on Form 8-K/A filed August 3, 2006)
4.1	Form of Common Stock Certificate. (Incorporated by reference to Exhibit 4.4 to the Registrant's Current Report on Form 8-K/A filed August 3, 2006)
4.2	Indenture, dated as of December 1, 1995 between Southwestern Energy Company and The First National Bank of Chicago (now J.P. Morgan Chase Bank). (Incorporated by reference to Exhibit 4 to Amendment No. 1 to the Registrant's Registration Statement on Form S-3 (File No. 33-63895) filed on November 17, 1995)
4.3	First Supplemental Indenture between Southwestern Energy Company and J.P. Morgan Trust Company, N.A. as successor to the First National Bank of Chicago dated June 30, 2006. (Incorporated by reference to Exhibit 4.2 to the Registrant's Current Report on Form 8-K/A filed August 3, 2006)
4.4	Indenture dated June 1, 1998 by and among NOARK Pipeline Finance, L.L.C. and The Bank of New York. (Incorporated by reference to Exhibit 4.1 to the Registrant's Current Report on Form 8-K filed May 4, 2006)
4.5	First Supplemental Indenture dated May 2, 2006 by and among Southwestern Energy Company, NOARK Pipeline Finance, L.L.C., and UMB Bank, N.A. as successor to the Bank of New York (Incorporated by reference to Exhibit 4.2 to the Registrant's Current Report on Form 8-K filed May 4, 2006)
4.6	Second Supplemental Indenture between Southwestern Energy Company and UMB Bank, N.A. as successor to the Bank of New York dated June 30, 2006. (Incorporated by reference to Exhibit 4.3 to the Registrant's Current Report on Form 8-K/A filed August 3, 2006)
4.7	Amended and Restated Rights Agreement between Southwestern Energy Company and the First Chicago Trust Company of New York dated April 12, 1999. (Incorporated by reference to Exhibit 4.1 to the Registrant's Annual Report on Form 10-K (Commission File No. 1-08246) for the year ended December 31, 1999)
4.8	Amendment No. 1 to the Amended and Restated Rights Agreement between Southwestern Energy Company and Equiserve Trust Company as successor to the First Chicago Trust Company of New York dated March 15, 2002. (Incorporated by reference to Exhibit 4.1 to the Registrant's Annual Report on Form 10-K (Commission File No. 1-08246) for the year ended December 31, 2001)
4.9	Amendment No. 2 to the Amended and Restated Rights Agreement between Southwestern Energy Company and Computershare Trust Company, N.A. as successor to the First National Bank of Chicago dated June 30, 2006. (Incorporated by reference to Exhibit 4.5 to the Registrant's Current Report on Form 8-K/A filed August 3, 2006)
4.10	Guaranty dated June 1, 1998 by Southwestern Energy Company in favor of The Bank of New York, as trustee (the "Trustee"), under the Indenture dated as of June 1, 1998 between NOARK Pipeline Finance L.L.C. and the Trustee. (Incorporated by reference to Exhibit 4.6 to the Registrant's Annual Report filed on Form 10-K (Commission file No. 1-08246) for the year ended December 31, 2005)
4.11	Second Amended and Restated Credit Agreement dated February 9, 2007 among Southwestern Energy Company, JPMorgan Chase Bank, NA, SunTrust Bank, The Royal Bank of Scotland PLC, Royal Bank of Canada, Bank of America, N.A., and the other lenders named therein, JPMorgan Chase Bank, NA, as administrative agent, SunTrust Bank as syndication agent. (Incorporated by reference to Exhibit 4.11 to the Registrant's Annual Report on Form 10-K filed on March 1, 2007)

4.12	First Amendment dated October 12, 2007 to Second Amended and Restated Credit Agreement with JPMorgan Chase Bank, N.A., as Administrative Agent, and a lender under the facility, SunTrust Bank as Syndication Agent, Bank of America, N.A., Royal Bank of Canada and Royal Bank of Scotland plc dated February 9, 2007. (Incorporated by reference to Exhibit 4.1 to the Registrant’s Quarterly Report on Form 10-Q (Commission File No. 1-08246) for the period ended September 30, 2007)
4.13	Indenture dated January 16, 2008 among Southwestern Energy Company, the Guarantors named therein and The Bank of New York Trust Company, N.A., as trustee. (Incorporated by reference to Exhibit 4.1 to the Registrant’s Current Report on Form 8-K filed January 16, 2008)
4.14	Registration Rights Agreement by and between Southwestern Energy Company and J.P. Morgan Securities Inc., acting as representative of the initial purchasers dated January 16, 2008. (Incorporated by reference to Exhibit 4.3 to the Registrant’s Current Report on Form 8-K filed January 16, 2008)
4.15	Policy on Confidential Voting of Southwestern Energy Company. (Incorporated by reference to the Appendix of the Registrant's Definitive Proxy Statement (Commission File No. 1-08246) for the 2006 Annual Meeting of Stockholders)
10.1	Form of Second Amended and Restated Indemnity Agreement between Southwestern Energy Company and each Executive Officer and Director of the Registrant. (Incorporated by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K/A filed August 3, 2006)
10.2	Form of Executive Severance Agreement between Southwestern Energy Company and each of the Executive Officers of Southwestern Energy Company, effective February 17, 1999. (Incorporated by reference to Exhibit 10.12 of the Registrant's Annual Report on Form 10-K (Commission File No. 1-08246) for the year ended December 31, 1998)
10.3	Southwestern Energy Company Incentive Compensation Plan. (Incorporated by reference to Exhibit 10.2(b) to the Registrant's Annual Report on Form 10-K (Commission File No. 1-08246) for the year ended December 31, 1998)
10.4	Southwestern Energy Company Supplemental Retirement Plan as amended. (Incorporated by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed on February 19, 2008)
10.5	Southwestern Energy Company Non-Qualified Retirement Plan as amended. (Incorporated by reference to Exhibit 10.2 to the Registrant's Current Report on Form 8-K filed on February 19, 2008)
10.6	Southwestern Energy Company 1993 Stock Incentive Plan, dated April 7, 1993. (Incorporated by reference to Exhibit 10.4(e) to the Registrant's Annual Report on Form 10-K (Commission File No. 1-08246) for the year ended December 31, 1993)
10.7	Southwestern Energy Company 1993 Stock Incentive Plan for Outside Directors, dated April 7, 1993. (Incorporated by reference to Exhibit 10.4(f) to the Registrant's Annual Report on Form 10-K (Commission File No. 1-08246) for the year ended December 31, 1993)
10.8	Southwestern Energy Company 2000 Stock Incentive Plan dated February 18, 2000. (Incorporated by reference to the Appendix of the Registrant's Definitive Proxy Statement (Commission File No. 1-08246) for the 2000 Annual Meeting of Stockholders)
10.9	Southwestern Energy Company 2002 Employee Stock Incentive Plan, effective October 23, 2002. (Incorporated by reference to Exhibit 10.1 to the Registrant’s Current Report on Form 8-K filed on December 13, 2005)
10.10	Southwestern Energy Company 2002 Performance Unit Plan, as amended, effective December 8, 2005. (Incorporated by reference to Exhibit 10.1 to Registrant’s Current Report on Form 8-K filed on December 13, 2005)
10.11	Southwestern Energy Company 2004 Stock Incentive Plan. (Incorporated by reference to Appendix A to the Registrant’s Proxy Statement dated March 29, 2004)

10.12	Form of Incentive Stock Option Agreement for awards prior to December 8, 2005. (Incorporated by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed on December 20, 2004)
10.13	Form of Restricted Stock Agreement for awards prior to December 8, 2005. (Incorporated by reference to Exhibit 10.3 to the Registrant's Current Report on Form 8-K filed on December 20, 2004)
10.14	Form of Non-Qualified Stock Option Agreement for non-employee directors for awards prior to December 8, 2005. (Incorporated by reference to Exhibit 10.2 to the Registrant's Current Report on Form 8-K filed on December 20, 2004)
10.15	Form of Incentive Stock Option for awards granted on or after December 8, 2005 (Incorporated by reference to Exhibit 10.4 to the Registrant's Current Report on Form 8-K filed on December 13, 2005)
10.16	Form of Restricted Stock Agreement for awards granted on or after December 8, 2005 (Incorporated by reference to Exhibit 10.4 to the Registrant's Current Report on Form 8-K filed on December 13, 2005)
10.17	Form of Non-Qualified Stock Option Agreement for awards granted on or after December 8, 2005 (Incorporated by reference to Exhibit 10.4 to the Registrant's Current Report on Form 8-K filed on December 13, 2005)
10.18	Form of Restricted Stock Agreement for Special Incentives. (Incorporated by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed on December 14, 2006)
10.19	Project Services Agreement by and between SEECO, Inc., a wholly-owned subsidiary of Southwestern Energy Company, and Schlumberger Technology Corporation dated August 17, 2006. (Incorporated by reference to Exhibit 10.1 to the Registrant's Quarterly Report on Form 10-Q (Commission File No. 1-08246) for the period ended September 30, 2006)
10.20	Master Lease Agreement by and between Southwestern Energy Company and SunTrust Leasing Corporation dated December 29, 2006. (Incorporated by reference to Exhibit 10.22 to the Registrant's Annual Report on Form 10-K (Commission File No. 1-08246) for the year ended December 31, 2006)
10.21*	Stock Sale and Purchase Agreement by and between Southwestern Energy Company and SourceGas LLC dated November 9, 2007.
21.1*	List of Subsidiaries.
23.1*	Consent of PricewaterhouseCoopers LLP.
23.2*	Consent of Netherland, Sewell & Associates, Inc.
31.1*	Certification of CEO filed pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	Certification of CFO filed pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32*	Certification of CEO and CFO furnished pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

*Filed herewith